

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Electric Company 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

Volume No. 6

PUBLIC RECORD

CROSS-EXAMINATION - PART 1

Proceedings held via Microsoft Teams in the
above-entitled matter before Sally L. Wallace, J.D.,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Tuesday, September 10, 2024, at 9:00 a.m.

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DAO-3	Brian Allnutt, The battle against Michigan power outages yields little accountability, PLANET DETROIT (Mar. 1, 2024), https://planetdetroit.org/2024/03/dte-power-outages/ .	4367	4368
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DAO-9	Amy Lange & Jack Nissen, Affordability Connectivity Programs at Risk in Detroit and Abroad without Congressional Help, FOX 2 DETROIT (Apr. 3, 2024), https://www.fox2detroit.com/news/affordability-connectivity-program-at-risk-in-detroit-and-abroad-without-congressional-approval	4367	4368
DAO-10	WE THE PEOPLE MICHIGAN, GENTRIFICATION, POPULATION CHANGE, AND ELECTRIC GRID INVESTMENT (July 2023) (available at https://wethepeoplemi.org/wp-content/uploads/2023/08/DTE-Gentrification-Brief.pdf).	4367	4368
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DAO-22	Kim Riley, EEI takes targeted strike at EPA's power plant emissions rule, Daily Energy Insider (May 22, 2024), https://dailyenergyinsider.com/featured/43843-eei-takes-targeted-strike-at-epas-power-plant-emissions-rule/	4367	4368
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DAO-24	Matt Kasper, Coal and utility interests ask for, receive, bailouts to help failing power plants, Energy and Policy Institute (Oct. 2, 2017), https://energyandpolicy.org/bailouts-for-coal-and-nuclear-plants/ .	4367	4368
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DAO-118	Adam Zuvanich, Hurricane Beryl caused at least 20 Houston-area deaths, with half power outage-related, Houston Public Media (Jul. 18, 2024)	4447	4447
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DAO-148	Excerpt from Ill. Com. Comm'n No. 23-0067, Order (Nov. 16, 2023)	4447	4447
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DAO-202	Introduction, HOME ENERGY AFFORDABILITY GAP.	4527	4527
DAO-203	Michigan Public Service Commission, Energy Affordability and Accessibility Collaborative, Assistance Programs and Credits Diagram FY20	4527	4527

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DAO-205	Christopher Jones & Daniel M. Kammen, Spatial Distribution of US Household Carbon Footprints Reveals Suburbanization Undermines Greenhouse Gas Benefits of Urban Population Density, 48 ENVTL. SCI. & TECH. 895 (2014).	4527	4527
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DAO-208	ADM Associates, Evaluation of the Percentage of Income Payment Plans.	4527	4527
DAO-209	California Public Utilities Commission, Low-Income Oversight Board 3rd Quarterly Meeting (Sept. 29, 2021).	4527	4527
DAO-210	Michigan Department of Environment, Great Lakes, and Energy, Energy Efficiency in Michigan Homes.	4527	4527
DAO-211	U.S. Department of Energy, Energy Saver: Furnaces and Boilers	4527	4527
DAO-212	Eric D. Lebel et al., Methane and NO x Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes, 56 ENVTL. SCI. & TECH. 2529 (2022).	4527	4527
DAO-213	Brett C. Singer et al., Pollutant Concentrations and Emission Rates from Natural Gas Cooking Burners Without and With Range Hood Exhaust in Nine California Homes, 122 BUILDING & ENV'T 215 (2017).	4527	4527

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DAO-215	Taylor Gruenwald et al., Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States, 20 INT'l J. ENVTL. RES. & PUB. HEALTH 1 (2023).	4527	4527
DAO-216	Boris R. Lukanov & Elena M. Krieger, Distributed Solar and Environmental Justice: Exploring the Demographic and Socio-Economic Trends of Residential PV Adoption in California, 134 ENERGY POL'Y 110935 (2019).	4527	4527
DAO-217	Galen Barbose, et al., Income Trends of Residential PV Adopters: An Analysis of Household-Level Income Estimates (Apr. 2018).	4527	4527
DAO-218	Arjun Makhijani, Yunus Kinkhabwala, et al., Energy Affordability in Maryland (Feb. 2023).	4527	4527
DAO-219	DTE Energy, Demand Response to Lower Your Energy Costs (last accessed July 11, 2024).	4527	4527
DAO-220	Kari Lydersen, DOE Looks to Illinois to Lead on Low-Income Community Solar, ENERGY NEWS NETWORK (Aug. 18, 2022).	4527	4527
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DAO-224	Benjamin K. Sovacool et al., Energy Decisions Reframed as Justice and Ethical Concerns, 1 NATURE ENERGY 1 (2016).	4527	4527
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DAO-254	HR Lineup, Absenteeism in the Workplace: Impact, Causes, Policies & Solutions (Dec. 19, 2023)	4568	4568
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DAO-256	APPRISE, 2018 NATIONAL ENERGY ASSISTANCE SURVEY, FINAL REPORT (Dec. 2018)	4568	4568
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DAO-265	Princeton Eviction Lab, Michigan and Wayne County 2018 reports	4568	4568
DAO-266	Bruce D. Meyer, et al., Homelessness and the Persistence of Deprivation: Income, Employment, and Safety Net Participation (Feb. 2, 2024)	4568	4568
DAO-267	U.S. DEPT. OF HOUSING AND URBAN DEVEL., GLOSSARY OF TERMS TO AFFORDABLE HOUSING	4568	4568
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DAO-269	Yannai Kashtan et al., Nitrogen Dioxide Exposure, Health Outcomes, and Associated Demographic Disparities Due to Gas and Propane Combustion by U.S. Stoves, 10 Science Advances (May 3, 2024)	4568	4568

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DAO-273	FOOD AND DRUG ADMINISTRATION, FOOD AND WATER SAFETY DURING OUTAGES AND FLOODS (last accessed on July 12, 2024)	4568	4568
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DAO-278	Tucker Oddleifson et al., Prefeasibility Analysis of Behind-the-Meter Distributed Energy Resources in Highland Park, MI: Highland Park Pathways to Power, NAT. RENEW. ENERGY LAB. (Mar. 2024)	4568	4568
DAO-279	Patrick Gibbs, Housing Characteristics and Energy Burden Analysis for Highland Park, Michigan, NAT. RENEW. ENERGY LAB. (Mar. 2024)	4568	4568

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DAO-280	Erik Pohl et al., Distribution Grid Impact Study in Highland Park, Michigan: Understanding Rooftop Solar, Behind-the-Meter Energy Storage, Electric Vehicle Charging, and Building Electrification, NAT. RENEW. ENERGY LAB. (Mar. 2024)	4568	4568
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DAO-284	EPA, REPORT ON THE SOCIAL COST OF GREENHOUSE GASES: ESTIMATES INCORPORATING RECENT SCIENTIFIC ADVANCES (Nov. 2023)	4568	4568
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Toyia Watts Exhibits			
DAO-311	Mike Wilkinson, Michigan Near Tops in Nation for Outages. Utilities Want to Raise Rates., BRIDGE MICH. (May 28, 2024), https://www.bridgemi.com/quality-life/michigan-near-tops-nation-outages-utilities-want-raise-rates .	4664	4664
DAO-312	Brian Allnutt, Michigan Ranks #2 for Power Outages, PLANET DETROIT (Jan. 19, 2024), https://planetdetroit.org/2024/01/michigan-ranks-2-among-states-for-power-outages/ .	4664	4664
DAO-313	CITIZENS UTIL. BD., UTILITY PERFORMANCE REPORT: RANKING MICHIGAN AMONG THE STATES (2023).	4664	4664
DAO-314	Christopher Flavelle, A New, Deadly Risk for Cities in Summer: Power Failures During Heat Waves, N.Y. TIMES (July 2, 2021), https://www.nytimes.com/2021/05/03/climate/heat-climate-health-risks.html .	4664	4664
DAO-315	Brian Allnutt, The Battle Against Michigan Power Outages Yields Little Accountability, PLANET DETROIT (Mar. 1, 2024), https://planetdetroit.org/2024/03/dte-power-outages .	4664	4664
DAO-316	Juan Pablo Cavallo & Joan Casey, Weather-Related Power Outages Rising, CLIMATE CENT. (Apr. 23, 2024), https://www.climatecentral.org/climate-matters/weather-related-power-outages-rising .	4664	4664
DAO-317	Letter from DTE to Toyia Watts (April 22, 2024).	4664	4664

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEC-127	Revised MNSCST-1.1a-d	3577	3580
MEC-128	2023-04-18 AAA Meeting Presentation	3577	3580
MEC-129	Commission Orders relating to EAAC 2021-2022	3577	3580
	- - -		
<u>MEIU</u>			
MEIU-1	(LSS-1) Resume of Dr. Laura S. Sherman	4044	4044
MEIU-2	(LSS-2) California Public Utilities Commission, Docket No. A.14-04-014, "Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement," January 28, 2016	4044	4044
MEIU-3	(LSS-3) California Public Utilities Commission, Decision 22-11-040, "Decision on Transportation Electrification Policy and Investment," November 21, 2022	4044	4044
MEIU-4	(LSS-4) Connecticut Public Utilities Regulatory Authority Final Decision, Docket No. 21-08-06, "Annual Review of the Electric Vehicle Charging Program - Year 1," December 15, 2021	4044	4044
MEIU-5	(LSS-5) Georgia Public Service Commission, Docket No. 44280, "Order Adopting Settlement Agreement as Modified," December 30, 2022	4044	4044
MEIU-6	(LSS-6) Illinois Commerce Commission Order, 22-0432/22-0442 (Cons.), "Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX and Investigation into Commonwealth Edison Company Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45," March 23, 2023 Penn Reporting, LLC - lori.penn@yahoo.com	4044	4044

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEIU-7	(LSS-7) Massachusetts Department of Public Utilities, Docket 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017	4044	4044
MEIU-8	(LSS-8) Massachusetts Department of Public Utilities, Docket 21-90, "Order on Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022	4044	4044
MEIU-9	(LSS-9) Massachusetts Department of Public Utilities, Docket 17-13, "Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of its Electric Vehicle Market Development Program, and of its Electric Vehicle Market Development Program Provision, pursuant to G.L. c. 164, §§ 76, 94, and Acts of 2016, c. 448," September 10, 2018	4044	4044
MEIU-10	(LSS-10) Massachusetts Department of Public Utilities, Docket 21-91, "Order on Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022	4044	4044
MEIU-11	(LSS-11) Minnesota Public Utilities Commission, Docket 18-643, "Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting reporting Requirements," July 17, 2019	4044	4044

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEIU-12	(LSS-12) Missouri Public Service Commission, Docket 2018-0132, "Order Approving Second Stipulation and Agreement," February 6, 2019	4044	4044
MEIU-13	(LSS-13) New Mexico Public Regulation Commission Final Order Adopting Recommended Decision, Case No. 20-00237-UT, "I/M/O Public Service Company of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program," November 12, 2021	4044	4044
MEIU-14	(LSS-14) New York Public Service Commission, Case 18-E- 0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 16, 2020	4044	4044
MEIU-15	(LSS-15) Pennsylvania Public Utilities Commission, Docket No. R-2018-3000124, "Opinion and Order," December 20, 2018	4044	4044
MEIU-16	(LSS-16) Rhode Island Public Utilities Commission, Docket No. 4780, "Re: the Narragansett Electric Company d/b/a National Grid Proposed Power Sector Transformation Vision and Implementation Plan," August 16, 2018	4044	4044
MEIU-17	(LSS-17) Virginia Division of Public Utility Regulation, Case No. PUR-2019-00154, "Final Order. Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service," March 26, 2020	4044	4044
MEIU-18	(LSS-18) PUBLIC Attachment "U-21534 MEIUDE-1.4 EV Sales Forecast"	4044	4044

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEIU-19	(LSS-19) CONFIDENTIAL Attachment "NDA U-21534_MEIUDE-1.4_DTE EV Charging market model v.40"	4044	4044
MEIU-20	(LSS-20) Discovery Response MEIUDE-2.1a	4044	4044
MEIU-21	(LSS-21) Discovery Response MEIUDE-2.4a	4044	4044
MEIU-22	(JRB-1) Curriculum Vitae of Justin R. Barnes	4120	4129
MEIU-23	(JRB-2) Discovery Response MEIUDE-1.20(a)	4120	4129
MEIU-24	(JRB-3) Discovery Response MEIUDE-1.19(a)	4120	4129
MEIU-25	(JRB-4) Discovery Responses MEIUDE-1.18 (a), (e) & (f)	4120	4129
MEIU-26	(JRB-5) Discovery Response MEIUDE-1.18(b)	4120	4129
MEIU-27	(JRB-6) Discovery Response MEIUDE-1.18(d)	4120	4129
MEIU-28	(JRB-7) Discovery Response MEIUDE-1.27(a)	4120	4129
MEIU-29	(JRB-8) Discovery Response MEIUDE-3.3(b)	4120	4129
MEIU-30	(JRB-9) Discovery Response MEIUDE-3.3(a)	4120	4129
MEIU-31	(JRB-10) Illustrative Rate Comparison Report Format	4120	4129
MEIU-32	(LSS-22) Discovery Response EVgo-AG-1 4854-1714-0704, v. 2	4044	4044
MEIU-33	Company Responses to MEIU's Fourth Set of Discovery Requests 4.1a through 4.6b	4161	4161
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<u>NRD</u>			
NRD-1	Resume of Roger Colton	3855	3855
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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
<u>WALMART</u>			
WAL-1	Witness Qualifications Statement	4716	4717
WAL-2	Impact of DTE's Proposed Increase in ROE vs. DTE's Currently Approved ROE	4716	4717
WAL-3	Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2021 to Present	4716	4717
WAL-4	Impact of DTE's Proposed Increase in ROE vs. National Average ROE for Vertically Integrated Utilities (9.62%)	4716	4717
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<u>STAFF</u>			
S-1	Sch. A-1, A-1.2 (NICHOLS)	4929	4929
S-2	Sch. B1, B4 (HECHT)	4880	4881
S-3	Sch. C-1, C-1.1, C-14, C-15 (NICHOLS) Sch. C-5 (SCHREUR)	4920 4997	4929
S-4	Sch. D-1, D-2, D-3, D-4, D-5 (UFOLLA)	5004	5004
S-6	Sch. F2, F3, F4, F5, F8 (ISAKSON) Sch. F1.1, F1.2, F1.4, F1.5, P3, P4, X5, X6 (PUNG)	4891 4938	4891
Theresa McMillan-Sepkoski			
S-7.0	Co. Response TMS-1.1a Incentive Compensation	4916	4916
S-7.1	Incentive Compensation Company Witness Cooper Table 3	4916	4916
S-7.2	DTE Energy Co Long-Term Incentive Plan Booklet	4916	4916
S-7.3	Co. Response TMS-2.1a Restricted Stock	4916	4916

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
S-7.4	Regulated Marketing O&M Expense Updated with 2023 Actuals	4916	4916
S-7.5	Merchant Fees O&M Expense Updated with 2023 Actuals	4916	4916
Cody Matthews			
S-8.0	Discovery Response STDE-3.11h	5159	5159
S-8.1	Discovery Response STDE-3.11g	5159	5159
S-8.2	Discovery Response STDE-3.11i	5159	5159
Lauren Fromm			
S-9.0	Supporting Audit Response LF-1.1a	--	--
Jon DeCooman			
S-10.0	Blackstart Project redacted scoping documents	5043	5043
S-10.1	Comparison of requested, approved, and actual non-routine capital expenditures from Case No. U-21297	5043	5043
S-10.2	Monthly 2023 capital expenditures for select non-routine projects	5043	5043
S-10.3	Company discovery responses on Slocum cost increases	5043	5043
S-10.4	Slocum Pilot scoping document	5043	5043
S-10.5	Identification of contract work for Trenton Channel Battery	5043	5043
S-10.6	Breakout of 'Other Costs' category for Trenton Channel Battery	5043	5043
S-10.7	Company discovery responses on ANM pilot	5043	5043
S-10.8	Comparison of DGP and rate case project requests	5043	5043

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
Justin Hecht			
S-11.0	Company Response to MPSC Staff Audit Request JJH-1	4880	4881
Shannon Rueckert			
A-11	A-1.1 Tree Trim Regulatory Asset - Return On	4985	4985
Ryan Boutet			
S-12.1	DTE Response to Staff Discovery Questions Topic: Fleet Capital Purchases	5127	5127
S-12.2	DTE Response to Staff Discovery Questions Topic: Fleet Repair Expenses	5127	5127
S-12.3	DTE Response to Staff Discovery Questions Topic: Fleet Service Providers	5127	5127
S-12.4	DTE Response to Staff Discovery Questions Topic: Base Capitals Program - Actual 2023 Expenses	5127	5127
S-12.5	DTE Response to Staff Discovery Questions Topic: Summary of Relocations Projects	5127	5127
S-12.6	DTE Response to Staff Discovery Questions Topic: Fleet Capital - Actual 2023 Expenses	5127	5127
S-12.7	DTE Response to Staff Discovery Questions Topic: Fleet Capital - Actual 2024 Expenses	5127	5127
Joseph Ufolla			
S-13	Audit/Discovery Responses and Credit Opinion	50-4	50-4
S-14.0	REVISED N/A Projected Accounts 904, 925, and 926 Expenses for the Projected Test Period Ending December 31, 2025	4985	4985

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
S-14.1	REVISED N/A Uncollectible Accounts Expense for the Projected Test-Period Ending December 31, 2025	4985	4985
S-14.2	REVISED N/A Injuries & Damages Expense Normalization	4985	4985
S-14.3	REVISED N/A Employee Savings Plan, Active Healthcare, and Other Benefits Expense Projections for the Projected Test-Period Ending December 31, 2025	4985	4985
S-14.4	REVISED N/A Employee Savings Plan, Active Healthcare Expense, and Other Benefits Average Annual Growth Rates (AAGR)	4985	4985
Danielle Rogers			
S-15.1	Staff's Recommended IT Adjustments	5105	5105
S-15.2	Projects with Level 2 Cost Estimates	5105	5105
S-15.3	DTE Electric Audit Responses	5105	5105
S-15.4	Comparison of Level 2 and Level 3 cost estimates	5105	5105
S-15.5	Projects with Level 3 Cost Estimates	5105	5105
S-15.6	Comparison of Level 3 Cost Estimates and Actual Costs	5105	5105
S-15.7	Digital Worker Experience EOL Recommended Adjustment	5105	5105
Lisa Kindschy			
S-16.0	Actual capital expenditures through April 2024 for Non-Routine Steam Generation additions from discovery response STDE-2.1a and STDE-2.1b	5171	5171

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
S-16.1	Calculation of the reduction for the Monroe Bottom Ash Conversion project and updated project sheets from discovery response STDE-2.1d	5171	5171
S-16.2	Actual capital expenditures through April 2024 for Routine Maintenance over \$1 million from discovery response STDE-2.1a and STDE-2.1b	5171	5171
S-16.3	AACE Cost Estimate Classification System: Cost Estimating and Budgeting	5171	517
S-16.4	Reductions for PAT0 and PAT1 Routine Maintenance capital projects over \$1 million in 2024 and 2025	5171	5701
S-16.5	Actual capital expenditures through April 2024 for MERC & Fuel Supply from discovery response STDE-2.21a and STDE-2.21b	5171	5171
S-16.6	Actual capital expenditures through April 2024 for Nuclear Generation from STDE2.15a and STDE-2.15b and Reductions for Nuclear capital projects in 2024 and 2025	5171	5171
S-16.7	Updated O&M Exhibits for Steam, M 1 ERC & Fuel Supply, Nuclear and Other Power Generation using a 2023 Historic Year	5171	5171
Elaina Braunschweig			
S-17.0	DTE's Audit Response	3518	3518
S-17.1	Residential Income Assistance and Residential Senior Citizen Credit Projection Support	3518	3518
S-17.2	"Affordability, Alignment, and Assistance Subcommittee 12/4/2023"	3518	3518

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
Brittney Klocke			
S-18.1	Audit Response BMK-1.2	5097	5097
S-18.2	Audit Response BMK-1.3	5097	5097
S-18.3	Audit Response BMK-1.4	5097	5097
Mark Pung			
S-19	Response to Staff Audit Request MJP-1 (U-21260, Exhibit A-22, 2023 Energy Sales Revenue Net of Fuel Cost)	--	--
Tayler Becker			
S-20.0	(TJB-1) Company Discovery Response	5028	5028

- - -

1 Tuesday, September 10, 2024

2 At 9:00 a.m.

3 - - -

4 (Hearing resumes following adjournment of Monday,
5 September 9, 2024.)

6 JUDGE WALLACE: All right. We are back
7 on the record in Case No. U-21534, In the matter of the
8 application of DTE Electric for authority to increase its
9 rates, amend its rate schedules and rules governing the
10 distribution and supply of electric energy, and for
11 miscellaneous accounting authority. I am Sally Wallace,
12 I've been assigned to preside over the evidentiary
13 hearing in this matter. I'll note again for the record
14 that the Commission will be reading the record.

15 I'm going to go ahead and take
16 appearances of people who are here so far, beginning with
17 you, Mr. Christinidis.

18 MR. CHRISTINIDIS: Thank you, your Honor.
19 Jon Christinidis on behalf of DTE Electric. Also with me
20 today will being John Janiszewski and Breanne Reitzel to
21 bind in the Company's testimony.

22 JUDGE WALLACE: Good morning,
23 Mr. Christinidis. Commission Staff.

24 MS. DURIAN: Good morning, your Honor.
25 Heather Durian on behalf of Michigan Public Service
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1 Commission Staff. Also entering the appearances of Amit
2 Singh, Michael Orris, and Monica Stephens, and Mr. Orris
3 will be handling the binding in today.

4 JUDGE WALLACE: All right. Good morning,
5 Ms. Durian. Mr. King or Mr. Moody.

6 MR. KING: Good morning, your Honor.
7 Joel King appearing this morning on behalf of Attorney
8 General Dana Nessel.

9 JUDGE WALLACE: Good morning, Mr. King.
10 Mr. Bzdok or Ms. Andrews.

11 MS. ANDREWS: Good morning, your Honor.
12 T.J. Andrews and Christopher Bzdok on behalf of the
13 Michigan Environmental Council, Natural Resources Defense
14 Counsel, Sierra Club, and Citizens Utility Board of
15 Michigan.

16 JUDGE WALLACE: Good morning,
17 Ms. Andrews. Mr. Abrams.

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

23 JUDGE WALLACE: Good morning, Mr. Abrams.
24 MEIU, Foundry Association, Energy Michigan. (No
25 response.)

1 Mr. Boehm.

2 MR. BOEHM: Good morning, your Honor.

3 Kurt Boehm appearing on behalf of The Kroger Company.

4 JUDGE WALLACE: Good morning, Mr. Boehm.

5 Mr. Ben King, Utility Workers Union. (No response.)

6 Ann Arbor and MAUI, and/or.

7 MS. BRADER: Hi. Valerie Brader
8 appearing on behalf of both Ann Arbor and MI-MAUI, and
9 also entering an appearance for the City of Ann Arbor by
10 Valerie Jackson. Depending on when you do bind in, I
11 will most likely bind in for both, but Ms. Jackson will
12 cover one hour of the hearing this morning for a previous
13 commitment.

14 JUDGE WALLACE: O.K. Good morning,
15 Ms. Brader. Mr. Templeton.

16 MR. TEMPLETON: Good morning, your Honor.
17 Mark Templeton entering an appearance on behalf of
18 Soulardarity and We Want Green, Too, collectively known
19 as the Detroit Area Advocacy Organizations in this
20 proceeding. Also entering an appearance on behalf of my
21 colleague Jacob Schuhardt. And either Mr. Schuhardt or I
22 will do the bind-in, depending upon the exact timing.

23 JUDGE WALLACE: O.K., great. Good
24 morning, Mr. Templeton. Ms. Horne.

25 MS. HORNE: Good morning, your Honor.

1 Melissa Horne on behalf of Walmart, Inc.

2 JUDGE WALLACE: Good morning, Ms. Horne.
3 Mr. Campbell.

4 MR. CAMPBELL: Good morning, your Honor.
5 Steve Campbell of Clark Hill, PLC, on behalf of the
6 Association of Businesses Advocating Tariff Equity.

7 JUDGE WALLACE: Good morning,
8 Mr. Campbell. Mr. Vijaykar.

9 MR. VIJAYKAR: Good morning, your Honor.
10 Nikhil Vijaykar on behalf of EVgo Services, LLC.

11 JUDGE WALLACE: Good morning.
12 Ms. Flower.

13 MS. FLOWER: Good morning, your Honor.
14 Olivia Flower on behalf of ITC Transmission, and entering
15 appearances this morning for my colleagues Richard Aaron,
16 Hannah Buzolits, and Courtney Kissel.

17 JUDGE WALLACE: Good morning. Anybody
18 here from Michigan Telecommunications Association? (No
19 response.)

20 O.K. Mr. Bright.

21 MR. BRIGHT: Good morning, your Honor.
22 Stephen Bright on behalf of Electrify America, LLC.

23 JUDGE WALLACE: Good morning, Mr. Bright.
24 Mr. Keskey or Mr. Coyer. (No response.)

25 All right. I'll run them up later.

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1 All right. Everybody's gotten their
2 testimony and exhibit lists to Ms. Penn, correct? I'll
3 take that as a yes.

4 COURT REPORTER: I'm still waiting on a
5 couple things.

6 JUDGE WALLACE: O.K. If you're one of
7 the ones who has a thing that she's waiting on, please
8 get that to Ms. Penn ASAP.

9 All right. As we discussed before we
10 went on the record, the Company's last witness has been
11 waived, so it's time to move on to bind in the remainder
12 of DTE Electric's case. Mr. Christinidis, could you
13 proceed, please.

14 MR. CHRISTINIDIS: Yes, your Honor.
15 Pursuant to stipulation of the parties, and there are a
16 number of discovery responses that will be coming in
17 through other parties as a consequence of the
18 stipulation, and the remainder of the Company's
19 parties -- excuse me -- Company's witnesses have been
20 waived for cross-examination, we'll bind them in.

21 And so the first one that, first witness
22 for the Company being bound in would be Theresa M.
23 Uzenski. I can proceed when the court reporter is ready.

24 COURT REPORTER: I'm ready.

25 MR. CHRISTINIDIS: All right.

1 Ms. Uzenski sponsored Qualifications and Revised Direct
2 Testimony of Theresa M. Uzenski that is comprised of 98
3 pages. Ms. Uzenski also sponsored Rebuttal Testimony,
4 consisting of a cover sheet and 20 pages of questions and
5 answers. She has large number of exhibits and schedules
6 here, I will go through them, and if you hear or you hear
7 something you need to share, let me know. So the first
8 direct exhibit sponsored by Ms. Uzenski is Exhibit A-2,
9 which also includes Schedule B2, Schedule B3, Schedule
10 B4, Exhibit -- excuse me again -- Exhibit A-2 Schedule
11 B5, Schedule B5.1, Schedule B6, Schedule B6.1, Schedule
12 B6.2, and Schedule B7, those are all again associated
13 with Exhibit A-2. Ms. Uzenski's next exhibit and series
14 of schedules are as follows: Exhibit A-3 Schedule C1,
15 Schedule C1.1, Schedule C3, Schedule C4, Schedule C5,
16 Schedule C6, Schedule C11, Schedule C14, Schedule C15,
17 Schedule C16, C17, C18, C19, C20, and C-21, again, all
18 associated with Exhibit A-3. Ms. Uzenski also sponsors
19 Exhibit A-12, and the associated schedules for Exhibit
20 A-12 supported by Ms. Uzenski are Schedule B2, Schedule
21 B3, Schedule B4, Schedule B4.1, Schedule B4.2, Schedule
22 B4.3, B4.4, B4.5, B5, and B5.8. Moving on to
23 Ms. Uzenski's next direct exhibit, it's Exhibit A-13 and
24 the following schedules associated with Exhibit A-13.
25 Those schedules are Schedule C1, Schedule C1.1, Schedule

1 C3, Schedule C5, C5.6.2, Schedule C5.9.1, Schedule
2 C5.9.3, Schedule C5.10, Schedule C5.10.1, Schedule C5.15,
3 Schedule C5.17, Schedule C6, Schedule C11, Schedule
4 C11.1, Schedule C12, and finally for her direct exhibits
5 and schedules, Schedule C13. Again, all those associated
6 with Exhibit A-13. She also sponsors some rebuttal
7 exhibits, which are designated as Exhibit A-37 Schedules
8 B1 -- excuse me -- Schedules BB1, so that's 2Bs 1, and
9 BB2, and BB3. So with that, your Honor, the Company
10 would move the, that Ms. Uzenski's Qualifications,
11 Revised Direct Testimony, and Rebuttal Testimony be
12 admitted into the record, and move the admission of the
13 aforementioned exhibits and schedules.

14 JUDGE WALLACE: Thank you,
15 Mr. Christinidis. We'll go ahead and admit all of the
16 exhibits after everybody because there's so many people
17 on some of these exhibits.

18 Is there any objection to binding in the
19 revised direct testimony of Ms. Uzenski?

20 Hearing none, the testimony is bound in.

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

23 Hearing none, the testimony is bound in.

24 And does anybody have any objection to
25 any of the exhibits or schedules identified by

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1 Mr. Christinidis?

2 Again, we'll admit those, all of the
3 Company's exhibits and schedules once we've got all the
4 testimony in.

5 (Testimony Bound In.)

6 - - -

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 ; 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) allows for a payout within a range of zero
11 to 200% of the target, depending on actual results achieved. Short-term incentive
12 expense in 2022 includes \$1.4 million for amounts paid above the 100% target,
13 offset by \$0.6 million of prior period adjustments. Since payments above the target
14 and prior period adjustments may not recur, I have removed those amounts.

15

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

18 A49. The instant rate case assumes that for electric sales, historical normal weather will
19 occur for the forecast period. Thus, for comparison purposes the historical test year
20 must be adjusted to a normal weather basis. Weather was warmer than normal in
21 2022, increasing DTE Electric's pretax margin by \$32.8 million, and NOI by \$24.3
22 million, as shown on Schedule C21. Underlying the \$32.8 million pretax margin
23 increase was sales revenue of \$42.5 million offset in part by an increase in power
24 supply cost of \$9.7 million. Company Witness Leuker discusses the weather
25 impacts in more detail.

Line
No.

1

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

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

13

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

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

20

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

22 A52. Line 38 adds \$37.5 million of AFUDC income to offset the impacts of including
23 construction work in progress (CWIP) in rate base. The federal, state, and local
24 income tax expense related to AFUDC and interest income is already included in

Line
No.

1 the income tax expense displayed on line 1, columns (i) and (j) of Exhibit A-3,
2 Schedule C1.1.

3

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

12

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

16

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

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

24

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

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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 support the O&M
16 expenses and describe them in their direct testimony. These witnesses also support
17 the changes from the historic to the projected period within their respective areas.
18 I support the inflation rates used in their projections. I support the Corporate Staff
19 Group forecast and will explain the details later in my testimony. I also developed
20 Injuries and Damages expense and Environmental Remediation costs based on an
21 historical average. I have summarized the development of the forecasted O&M
22 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. I assumed the same rate for contract
4 labor since a portion of our contract workforce comes from the same unions as the
5 DTE union employees. The inflation rate for non-labor costs is based on a
6 consumer price index (CPI)-Urban published by S&P/IHS Markit. I used the labor
7 and non-labor rates to calculate a composite rate of inflation for 2023, 2024, and
8 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, 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 Hooper, be
5 continued in this case, and support the amortization of previously deferred balances.
6 I am also sponsoring the amortization of the PERC regulatory asset reflected on
7 Witness Davis's O&M exhibit, the amortization of deferred Advanced Distribution
8 Management System (ADMS) program costs on Witness Kryscynski's O&M
9 exhibit, the amortization of the Advanced Customer Pricing Pilot (ACPP) and Time
10 of Day (TOD) regulatory assets on Witness Hastios's O&M Exhibit, and the
11 amortization of deferred program costs for Charging Forward on Witness Bennett's
12 O&M exhibit.

13

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

16 A65. Yes. Witness Hooper 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 Hooper'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 s forecast for pension costs?**

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

10

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

13 A67. Exhibit A-13, Schedules C5.12.1 and C5.12.2, sponsored by Witnesses Fix and
14 Hooper, detail the components of Pension and OPEB costs. Each schedule has a
15 reconciliation of total cost to expense. A portion of the service cost component is
16 capitalized to CWIP/Plant based on the related labor capitalized. Effective in 2018,
17 the non-service cost components cannot be charged to capital under GAAP.
18 Instead, the non-service costs that would have been capitalized under the traditional
19 accounting treatment (but expensed under GAAP) are being recorded to a
20 regulatory asset (or liability if cost is negative) instead of plant. The regulatory
21 asset or liability is depreciated using the prior year's composite depreciation rate
22 for plant in service, with the expense recorded to a unique account within
23 Depreciation and Amortization expense. This treatment, approved in Case No. U-
24 18255, results in recognizing the same expense and rate base that would have
25 occurred under the historical accounting and ratemaking method.

Line
No.

1 **Q68. How does this impact Witnesses Fix and Hooper's exhibits?**

2 A68. The regulatory treatment is reflected on line 18 and line 16 of Witnesses Fix and
3 Hooper's Exhibit A-13, Schedules C5.12.1 and C5.12.2, respectively. The amount
4 previously shown as capitalized to plant has been bifurcated into two lines. Line
5 17 of C5.12.1 and line 15 of C5.12.2 represents the capitalized service costs
6 recorded to CWIP/Plant, and line 18 of C5.12.1 and line 16 of C5.12.2 represents
7 the capitalized non-service costs which are now recorded to a regulatory asset or
8 liability.

9

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

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

16

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

19 A70. The calculation of the deferral and related amortization expense is shown on my
20 Exhibit A-13, Schedule C5.17. Lines 2 through 4 show the difference between
21 PERC actual and forecasted expenses and the \$15 million base amount. The PERC
22 deferral amounts on line 4 are amortized over the subsequent five years. Lines 7
23 through 14 show the annual expense for each vintage year and the total amortization
24 that will occur in the projected period on line 15. The projected period amount of
25 \$4.9 million is carried to Witness Davis's Exhibit A-13, Schedule C5.3, line 22,

Line
No.

1 column (n). The projection adjustment of \$11.4 million in column (l) is simply the
2 difference between the forecasted amortization expense and the actual historical
3 expense.

4

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

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

18

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

20 A72. A forecast adjustment of \$5.0 million related to a change in the Company's
21 capitalization policy related to pole inspection costs is included within Witness
22 Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 20, column (j). (See exhibit
23 footnote number 6.) As explained in Case No. U-21297, the Company has
24 reviewed and updated its policy related to pole inspection and testing costs.
25 Effective January 1, 2023, the Company no longer capitalizes pole inspection and

Line
No.

1 testing costs. As a result, Witness Kryscynski has included a projection adjustment
2 to Account 593 Maintenance of Overhead Lines in the amount of \$5.0 million on
3 Exhibit A-13, Schedule C5.6, line 20, column (j) to reflect inspection costs in
4 O&M. This amount is supported by Witness Elliott Andahazy on Exhibit A-12,
5 Schedule B5.4.8

6

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

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

19

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

21 A74. Yes. In Case No. U-20162, the Commission approved the Company’s original
22 Charging Forward program intended to develop infrastructure related to electric
23 powered vehicles and the costs for the program are to be deferred to a regulatory
24 asset. In Case Nos. U-20935, U-20836, and U-21297 the Commission approved
25 additional components to the Charging Forward program. Per the Order in Case

Line
No.

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

9

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

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

24

Line
No.

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

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

9

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

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

24

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

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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
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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

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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

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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
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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.

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 Fix.

13

14 **Q152. Why is there an item called “Monroe Regulatory Asset” on line 41 of Exhibit**
15 **A-12, Schedule B4.2?**

16 A152. As previously discussed, the July 26, 2023 Order in the Company’s IRP in Case
17 No. U-21193 requires (among other things) the Company to securitize
18 approximately \$845 million after the retirement of the Monroe Power Plant,
19 expected in 2032. The portion of the plant to be securitized will remain classified
20 within plant in service until it is retired. The balance of the plant not being
21 securitized is to be recovered as a regulatory asset over fifteen years.

22

23 **Q153. Why does the Monroe Regulatory Asset have a zero balance on line 41?**

24 A153. The Order in Case No. U-21193 requires the overall return on the regulatory asset
25 to reflect a return on equity of 9%. To accomplish this, I have excluded the

Line
No.

1 regulatory asset from the balances underlying the base rate revenue deficiency
2 calculations. A separate rate of return for the Monroe regulatory asset is supported
3 by Witness Vangilder on Exhibit A11, Schedule A1.2.

4

5 **Q154. How was the Monroe Regulatory Asset balance calculated?**

6 A154. Refer to Exhibit A-12, Schedule B4.5. The total Monroe plant balance forecasted
7 for December 31, 2024 is \$3.2 billion as shown in column (a), line 9. To determine
8 how much of this should be reclassified to the regulatory asset, I had to subtract the
9 2024 amount that will remain in plant and eventually be securitized after the plant
10 is retired in 2032. Lines 13 through 16 calculate the 2024 amount that will result
11 in the agreed upon securitization value of \$845 million in 2032. That amount is
12 \$1.1 billion as shown on line 16. The \$1.1 billion will remain in plant and be
13 depreciated at 2.82% based on authorized depreciation rates. This results in a net
14 plant balance of \$845 million on December 31, 2032, as proven out in columns (c)
15 through (k). Subtracting the \$1.1 billion to be securitized from the \$3.2 billion total
16 plant balance, results in the \$2.1 billion net plant amount to be reclassified to the
17 regulatory asset, as shown in column (b). This amount is carried to Exhibit A-12,
18 Schedule B4.4, line 3.

19

20 **Q155. How is the Monroe regulatory asset calculated on Exhibit A-12, Schedule**
21 **B4.4?**

22 A155. The beginning balance on line 3 is carried from Exhibit A-12, Schedule B4.5. In
23 column (d), capital additions and amortization for 2025 are shown on lines 5 and 6.
24 Per the Case No. U-21193 July 26, 2023 IRP Order, capital additions approved in
25 rate cases will be added to the regulatory asset. Witness Guillaumin supports the

Line
No.

1 capital expenditures which are shown on Exhibit A-12, Schedule B5.1, page 2. The
2 amortization is calculated based on a fifteen-year period per the Case No. U-21193
3 July 26, 2023 IRP Order. After reflecting the additions and amortization, the
4 projected ending balance for 2025 is shown on column (d), line 7. The simple and
5 thirteen-month averages are shown in column (f). The thirteen-month average from
6 column (f) line 8 is used by Witness Vangilder on his Exhibit A-11, Schedule A1.2
7 to calculate the return.

8

9 **Q156. What is the Ludington Regulatory Asset on line 42?**

10 A156. On May 18, 2023 the Commission approved a joint application by DTE Electric
11 and Consumers Energy in Case No. U-21310 to defer certain costs at the Ludington
12 Pumped Storage Plant resulting from defective work by a third party. The balance
13 represents costs deferred during 2023 after receipt of the Order.

14

15 **Q157. How was the Customer 360 Regulatory Asset on line 44 developed?**

16 A157. The Company implemented a new Customer Relationship and Billing system in
17 April 2017 called Customer 360. Pursuant to the September 26, 2016 Order in Case
18 No. U-17666, the Company deferred \$47 million for certain project expenses in
19 Account 182.3, Other Regulatory Assets. The Company also incurred \$16.6
20 million of post implementation costs during 2017. The Commission approved
21 recovery of the 2017 amount in Case No. U-20162. The deferred costs are being
22 amortized over a 15-year period, and the balance reflects annual amortization of
23 about \$4.2 million.

24

25 **Q158. What is the Residential Income Assistance regulatory asset on line 46?**

Line
No.

1 A158. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential
2 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base
3 amount. The balance reflects that in 2022, the Company issued more RIA credits
4 to customers than were reflected in the base. In Case No. U-20836, the Commission
5 ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective
6 with the Order in U-20836, any underspent amounts will be netted against any
7 regulatory assets recorded for overspent amounts. The projected balances were
8 based on a 13-month historical average.

9

10 **Q159. What is the Program Evaluation & Review Committee (PERC) regulatory**
11 **asset on line 47?**

12 A159. This balance represents deferred costs for certain nuclear O&M projects. As further
13 explained by Witness Davis, the Company executes PERC operations and
14 maintenance projects. The change in balance is projected based on the addition of
15 deferred costs less the amortization of deferred amounts over five years, as shown
16 on my Exhibit A-13, Schedule C5.17. As previously discussed, the Order in Case
17 No. U-18014 provided deferral treatment for any expenses over or under a \$4.9
18 million base amount, and the base was increased to \$15 million in Case No. U-
19 20561.

20

21 **Q160. What is the Advanced Distribution Management System (ADMS) regulatory**
22 **asset on line 48?**

23 A160. As previously discussed, the Company is installing an ADMS. The Commission
24 approved deferral of certain O&M costs as a regulatory asset with amortization over
25 fifteen years in Case No. U-20162. As shown on Exhibit A-12, Schedule B5.4,

Line
No.

1 page 1 of 26, line 25, these expenses were deferred in the amount of \$4.7 million
2 in the 2022 historical year and are projected to be \$3.6 million in the bridge period.
3 The regulatory asset balance is reduced by annual amortization of approximately
4 \$1.2 million in 2024 and 2025.

5

6 **Q161. What is the Charging Forward Regulatory Asset on line 49?**

7 A161. As previously discussed, in Case Nos. U-20162 and U-20935 the Commission
8 approved a program called Charging Forward to incentivize third parties to build
9 charging stations for electric vehicles by providing rebates. Per the Order, the
10 regulatory asset will be expensed over five years, concurrent with its inclusion in
11 base rates. Additionally, the Company requested, and received approval for, an
12 expansion of the Charging Forward program in Case Nos. U-20836 and U-21297.
13 The Orders provide for the same regulatory asset treatment for rebates paid to
14 schools, municipalities, gas stations, and similar customers. The projected balance
15 of \$47.1 million at December 2025 reflects deferred expense through the projected
16 period, supported by Witness Bennett, less cumulative amortization.

17

18 **Q162. What is the Advanced Customer Pricing Pilot Regulatory Asset on line 51?**

19 A162. Regulatory Asset treatment for certain implementation costs for the ACPP was
20 approved in the Commission's November 14, 2019 Order in Case No. U-20602.
21 The Commission approved deferral of up to \$7.3 million of costs. Actual costs
22 deferred totaling \$6.6 million are supported by Witnesses Bennett and Hatsios on
23 Exhibit A-13, Schedule C5.9.2, less cumulative amortization.

24

25 **Q163. What is the Time of Day (TOD) Regulatory Asset on line 52?**

Line
No.

1 A163. Regulatory Asset treatment for certain implementation costs for the Company's
2 Time of Day rate offering was approved in the Commission's November 18, 2022
3 Order in Case No. U-20836. The Company proposed a full implementation of TOD
4 rates, and the project incurred both capital and O&M expenses. The balance as of
5 December 2025 on line 52 of \$4.9 million reflects \$8.5 million of one-time
6 implementation costs offset by \$3.5 million of cumulative amortization expense
7 through the projected period. Witnesses Bennett and Hatsios support one-time
8 implementation costs on Exhibit A-13, Schedule C5.9.2.

9

10 My Exhibit A-13, Schedule C5.9.3 supports the calculation of annual amortization
11 expense of \$3.0 million for both the ACPP and TOD regulatory assets, which is
12 included in Customer Service O&M expense supported by Witness Hatsios.

13

14 **Q164. What is the Pension Capitalized on line 54?**

15 A164. As previously described regarding pension expense, this balance represents the
16 capitalized non-service cost components of pension expense. Because the non-
17 service costs became negative, the deferred balance is projected to become a
18 regulatory liability during 2023 and is shown on line 110.

19

20 **Q165. What is the Demand Response Regulatory Asset on line 55?**

21 A165. Witness Farrell describes the Company's Demand Response programs and the
22 reconciliation process. The Commission's February 18, 2021 Order in Case No.
23 U-20793 approved a \$3.0 million regulatory asset for under recovered 2019
24 Demand Response costs, and recovery via inclusion of amortization expense in
25 base rates. The Commission also issued an Order on February 10, 2022 approving

Line
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1 a settlement in the DR 2020 Reconciliation, Case No. U-21044, reflecting an under
2 recovery of \$1.4 million and \$202,000 of incentives. The balance also reflects a
3 settlement in the DR 2021 Reconciliation, Case No. U-21242, of \$4.3 million,
4 approved by Order on January 19, 2023. The \$1.8 million balance on December
5 31, 2025 reflects \$8.9 million of deferrals in 2021 through 2023 offset by
6 accumulated amortization of \$7.1 million.

7

8 **Q166. What is the Incentive Compensation Regulatory Asset on line 56?**

9 A166. In Case No. U-20836, the Commission approved recovery of \$12.7 million for
10 incentive compensation related to operating metrics. The approved base amount
11 assumed the Company achieved 60% of its targeted metrics. The Commission's
12 Order also provided for deferral treatment above or below the base amount, up to a
13 maximum 100% target level, to be refunded or recovered in DTE Electric's next
14 rate case. In Case No. U-21297, the Commission reduced the approved base amount
15 to \$10.1 million assuming the Company achieves approximately 52% of its targeted
16 metrics. The projected balance assumes that DTE Electric will not achieve 100%
17 of its target levels in 2023 based on projected performance. The amount below base
18 will be deferred to a regulatory liability. However, the Company expects to achieve
19 100% of its target levels in 2024 and will defer the difference between the actual
20 results and the annual base amount of \$10.1 million. Please refer to Exhibit A-13,
21 Schedule C5.10.1. Line 4 shows the amounts to be deferred by calendar year. The
22 calculation assumes the full amount of incentive expense will be approved for
23 recovery starting with the projected test period (January 1, 2025 to December 31,
24 2025) with no deferral required.

Line
No.

1

2 **Q167. Do you recommend that the incentive compensation deferral mechanism be**
3 **continued?**

4 A167. If the Commission approves the Company's forecasted incentive compensation
5 costs for the projected test period, the mechanism is unnecessary. However, if a
6 lesser amount is approved, I request the deferral be continued, but with some
7 modifications.

8

9 **Q168. What modifications to the incentive compensation mechanism are you**
10 **proposing?**

11 A168. I propose three modifications. First, the base amount should be reset equal to the
12 amount of incentive compensation approved for recovery in base rates in this case.
13 Second, the mechanism should apply to the totality of the Company's incentive
14 compensation program including the portion related to financial metrics. Witness
15 Fix supports the reasonableness and prudence of the Company's compensation
16 practices, including incentives tied to financial metrics. Third, the deferral should
17 cover the total actual payout, including amounts above 100% of the target. As
18 described in more detail by Witness Fix, the incentive program allows for a range
19 of payouts from zero to 200% of target. The incentive plan is designed to motivate
20 employees to achieve results beyond the target, further improving organizational
21 performance and benefitting customers. Since the Company must provide a refund
22 to customers if results fall below the baseline, it is reasonable to include the cost of
23 achieving exceptional results.

24

25 **Q169. What is the Low-Income Assistance Tracker on line 57?**

Line
No.

1 A169. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential
2 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base
3 amount. The balance reflects that in 2022, the Company issued more LIA credits
4 to customers than were reflected in the base. In Case No. U-20836, the Commission
5 ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective
6 with the Order in U-20836, any underspent amounts will be netted against any
7 regulatory assets recorded for overspent amounts. The projected balances were
8 based on a 13-month historical average.

9

10 **Q170. What is the Low-Income Payment Stability Plan regulatory asset on line 58?**

11 A170. In Case No. U-20929, the Commission authorized DTE Electric to defer costs
12 associated with its low-income customer assistance pilot (the Payment Stability
13 Plan or “PSP”). The PSP pilot creates a fixed maximum bill for participating
14 customers based on their income, rather than providing a fixed credit amount on a
15 variable bill like those provided by the residential income assistance or low-income
16 assistance programs. The balance consists of supplemental payments, arrears
17 forgiveness, benefit awards, and certain O&M implementation costs associated
18 with the pilot.

19

20 **Q171. What is causing the increase in Prepaid OPEB on line 62?**

21 A171. The Prepaid Post-Retirement Benefit asset increases from \$129.1 million on
22 December 2022 to \$194.3 million by December 2025. The year-to-year changes
23 are primarily the result of negative OPEB expense as explained by Witness Hooper.

24

Line
No.

1 **Q172. Can you explain the tax items on lines 59, 65 and 66 of Exhibit A-12, Schedule**
2 **B4.2?**

3 A172. Witness Wisniewski supports these tax-related assets. Line 59 represents the
4 excess deferred taxes that were remeasured related to reduction of the federal
5 corporate income tax rate change resulting from the 2017 Tax Cuts and Jobs Act
6 (TCJA). Line 65, Miscellaneous Tax Related, represents regulatory assets resulting
7 from changes in tax law such as Medicare Part D and the Michigan Corporate
8 Income Tax, reduced each year by amortization of approximately \$22.2 million.
9 Line 66, Recoverable Income Taxes, reflects a regulatory asset recorded in
10 conjunction with an offsetting ADFIT liability when ASC 740 (formerly FAS 109)
11 was adopted in 1993. It has scheduled reductions of \$2.4 million per year supported
12 by Witness Wisniewski. The ASC 740 balance sheet accounts do not affect the
13 revenue requirement. This accounting and rate treatment were approved by the
14 Commission in Case No. U-10083.

15

16 **Q173. How was Other Deferred Debits on line 68 of Exhibit A-12, Schedule B4.2**
17 **developed?**

18 A173. The Other Deferred Debits balance consists of pre-paid software, refundable spent
19 nuclear fuel storage costs, and short-term credit facility costs which were held
20 constant at the 13-month historical period. It also includes a pre-paid long-term
21 maintenance service agreement (LTSA) for the Blue Water Energy Center.
22 Changes in the LTSA balance reflect payments to the service provider, reduced by
23 transfers to capital and O&M as the services are rendered.

24

Line
No.

1 **Q174. What components make up the Liabilities and Other Credits reflected in**
2 **Exhibit A-12, Schedule B4.2, page 2 of 2?**

3 A174. Exhibit A-12, Schedule B4.2, page 2 of 2 has four major components:

- 4 1) Capitalization
- 5 2) Non-Current Liabilities
- 6 3) Current Liabilities
- 7 4) Deferred Credits

8

9 **Capitalization**

10 **Q175. How were the projected capitalization amounts determined in this case?**

11 A175. Capitalization (lines 73 through 83) reflects DTE Electric's permanent capital in
12 the form of long-term debt and common equity. Key long-term debt drivers
13 include new capital requirements, scheduled debt retirements, refinancing, level of
14 equity, and the amount of short-term debt. As previously discussed, the regulatory
15 liability related to the REP is a source of short-term debt. Schedule B4.2, line 76,
16 shows that long-term debt balances will increase during the forecast periods to
17 support DTE Electric's increasing asset base, as supported by Company Witness
18 Lepczyk.

19

20 Common equity balances on line 82 will also increase to finance the growing asset
21 base and to meet targeted capitalization percentages. Since projected earnings are
22 insufficient to meet the targeted equity capital percentages, common equity will
23 need to be funded from additional equity infusions as discussed and supported by
24 Witness Lepczyk. Projected common equity also reflects dividends required to
25 sustain and attract equity investors.

Line
No.

1 **Q176. What is the projected change in Capitalization?**

2 A176. Exhibit A-12, Schedule B4.2, line 76, reflects a long-term debt increase from
3 January 2023 to December 2024 of \$1,014.2 million primarily due to \$1,875.0
4 million of new debt issues, less redemptions of \$861.0 million. The \$144.3 million
5 long-term debt increase from January 2025 to December 2025 is primarily due to
6 new debt of \$1,300.0 million, less \$1,156.9 million of debt redemptions. Line 79
7 reflects Common Stock increases of approximately \$2.2 billion through December
8 2025 due to planned equity infusions as addressed by Witness Lepczyk, offset by
9 the removal of \$806.9 million of equity supporting the Monroe regulatory asset. A
10 portion of the Common Stock increases may be reduced from additional equity
11 based on the Commission Order in this case granting the rate relief requested.
12 Retained Earnings (line 80) decreases by \$62.6 million from January 2023 to
13 December 2024, resulting from net income of \$1,416.8 million, less common
14 dividend payments of \$1,479.4 million. Retained Earnings decreases from January
15 2025 to December 2025 by \$157.5 million resulting from twelve months ending
16 December 2025 net income of \$690.0 million less common dividend payments of
17 \$847.5 million. The changes in common equity are reconciled on Exhibit A-12,
18 Schedule B4.3.

19

20 **Non-Current Liabilities**

21 **Q177. What is included in Non-Current Liabilities on lines 85 through 91 of Exhibit**
22 **A-12, Schedule B4.2?**

23 A177. This section includes the liability for capital leases and injuries and damages.
24 Capital leases on line 85 is being held constant and represents the long-term portion
25 of the liability to offset the Net Capital Lease Property on line 10. The accumulated

Line
No.

1 provision for injuries and damages on line 87 is being held constant to the 13-month
2 historical average during the forecast period as new claims and settlements cannot
3 be predicted.

4

5 **Current Liabilities**

6 **Q178. What is included in Current Liabilities on lines 94 through 103 of Exhibit A-**
7 **12, Schedule B4.2?**

8 A178. This section includes short-term debt and payables. DTE Electric's short-term debt
9 balances on line 94 include the balances available from the REP regulatory liability.
10 The REP regulatory liability represents the temporary over-collection of DTE
11 Electric's REP surcharge. This liability is used by DTE Electric as an additional
12 source of financing in base rates. Interest on this liability is paid to our customers
13 via a credit in the Renewables Plan, lowering the revenue requirement for that
14 program.

15

16 **Q179. How did you forecast the balance for Accounts Payable on lines 96 and 97?**

17 A179. Accounts payable was forecasted based on a 13-month historical average as of
18 December 31, 2022.

19

20 **Q180. How did you forecast the remaining current liabilities?**

21 A180. Taxes Payable on line 98 reflects the timing of accruals and payments, as supported
22 by Witness Wisniewski. The changes in Interest Payable on line 99 also reflect the
23 timing of accruals and payments. Capital Leases Current on line 100 reflects the
24 current portion of the liability to offset the Net Capital Lease Property on line 10.
25 The fluctuations in line 102, Fermi 2 Outage accrual, result from forecasted

Line
No.

1 accruals and expenditures for the Fermi 2 planned outages supported by Witness
2 Davis on line 102. Other Current Liabilities on line 103 include vacation and
3 payroll accruals, customer deposits, and refundable contributions in aid of
4 construction, and are held constant at the historical 13-month average balance.

5

6 **Deferred Credits**

7 **Q181. What is included in Deferred Credits on lines 106 through 116 of Exhibit A-**
8 **12, Schedule B4.2?**

9 A181. The December 2022 balance related to line 106 Regulatory Liability - Renewable
10 Energy Program, was re-classified to short-term debt on my historical Exhibit A-2,
11 Schedule B6.2. Other Deferred Credits on line 116 includes refundable customer
12 advances, environmental reserves, and other accrued liabilities held constant at 13-
13 month average historic levels.

14

15 **Q182. What is the Regulatory Liability – OPEB on line 108?**

16 A182. The OPEB liability was established pursuant to the Commission's Order in Case
17 No. U-17767. Consistent with the treatment of pension expense, negative OPEB
18 expense, less amounts capitalized and transferred, are offset by a regulatory
19 liability. In Case No. U-21297, the Commission ordered that the Company must
20 amortize the OPEB regulatory liability of \$128.4 million as of the historical test
21 year (December 2022) over a seven-year period. The projected balance includes
22 additional deferrals due to projected negative OPEB expense offset by annual
23 amortization of \$18.3 million.

24

25 **Q183. What is the OPEB Capitalized on line 109?**

Line
No.

1 A183. As previously described regarding OPEB expense, this balance represents the
2 capitalized non-service cost components of OPEB expense.

3

4 **Q184. What is the Pension Capitalized on line 110?**

5 A184. As previously described regarding the pension capitalized asset, the non-service
6 costs became negative, and the balance is projected to become a regulatory liability
7 during 2023.

8

9 **Q185. What are the tax items on lines 113 through 115?**

10 A185. Witness Wisniewski supports lines 113 through 115. Accumulated Deferred
11 Income Taxes represents timing differences in the recognition of tax expenses for
12 the financial statements compared to the tax return. Both the federal and state
13 deferred tax balances reflect the netting of Deferred Tax Assets (Account 190)
14 against Deferred Tax Liabilities (Accounts 281, 282, and 283), consistent with the
15 presentation in the cost of capital calculation.

16

17 Deferred taxes on line 113 includes the outstanding tax liability balance to account
18 for tax benefits previously flowed through to ratepayers stemming from the 1993
19 enactment of ASC 740 as previously discussed. It is offset by the Regulatory Asset
20 (Recoverable Income Taxes) shown on Schedule B4.2, line 66. This accounting
21 and rate treatment were approved by the Commission in Case No. U-10083.

22

23 Accumulated Deferred Investment Tax Credits on line 114, supported by Witness
24 Wisniewski, are deferred tax credits generated and utilized by the Company with

Line
No.

1 the tax benefits flowing back to customers on the same basis as customers pay for
2 the assets that generated these tax credits.

3

4 The Tax Reform Regulatory Liability on line 115 results from the Tax Cuts and
5 Jobs Act of 2017, which among other things, lowered the corporate Federal tax rate
6 from 35% to 21%. The reduction in the tax rate required that all existing deferred
7 tax balances be re-measured using the 21% rate. The reduction in deferred taxes
8 was recorded to a regulatory liability to be refunded, generally, over the life of the
9 items causing the deferred tax, primarily plant. However, it also reflects accelerated
10 amortization of the liability per the Commission's April 8, 2021 Order in Case No.
11 U-20835. Witness Wisniewski explains the calculation of the regulatory liability
12 and the Company's refund schedule.

13

14 **MERC Closure Impacts**

15 **Q186. What impact does the anticipated closure of MERC have on the projections in**
16 **this case?**

17 A186. None. As described by Witness Milo, MERC will continue to operate until
18 generation using coal is discontinued at the Belle River Power Plant in mid-2026,
19 beyond the projected test period. Witness Milo supports the O&M and capital
20 expenditures required to safely operate MERC until it ceases operations.

21

22 **Q187. How does the Company plan to address the recovery of the plant assets**
23 **remaining after MERC ceases operations?**

24 A187. The Company proposes to include the remaining net book value of MERC's assets
25 in the securitization transaction for the Belle River coal assets. Securitization of

Line
No.

1 the coal handling assets for Belle River was approved in the Company's IRP Case
2 No. U-21193 by Commission Order issued on July 26, 2023. The Company
3 estimates that the net book value will be in the range of \$20 million.

4

5 **IRM Impacts**

6 **Q188. How does the Infrastructure Recovery Mechanism impact the projected**
7 **financials?**

8 A188. An overview of the mechanism is provided by Company Witness Foley. The
9 Commission Order in Case No. U-21297 approved an IRM for December 2023
10 through December 2025. The IRM capital expenditures and plant balances, the
11 related costs and revenues, and the related debt and equity are excluded from my
12 projected financial statements. This exclusion ensures that the revenue requirement
13 for the IRM is separate and distinct from the revenue requirement for base rates.
14 Company Witness Foley describes and supports the Company's proposal to extend
15 the IRM through 2027.

16

17 **Q189. Will the IRM expenditures be permanently excluded from base?**

18 A189. No. IRM investments will be transferred into the Company's overall rate base after
19 the investments have been made and put into service. The Company will reflect
20 this in the first general rate case after the investments have been reviewed through
21 an IRM reconciliation proceeding consistent with the Commission's Order in Case
22 No. U-21297. Until transferred to the Company's overall rate base rates, IRM
23 investments will be recovered through the IRM surcharge. Once the Commission

Line
No.

1 approves the transfer of assets from the IRM mechanism to the Company's overall
2 rate base, these assets be removed from the IRM surcharge.

3

4 **Q190. Is the Company proposing to reduce its future recovery by the amount of plant**
5 **that is being retired in this IRM program?**

6 A190. No. When plant is retired, the original recorded cost of the plant is both credited to
7 the plant in service accounts and charged to accumulated depreciation reserve; thus,
8 there is no change in the net plant balance related to the retirement. With no change
9 in net plant, there is no adjustment to the largest portion of the return-on-investment
10 portion of the revenue requirement calculation. As depreciation rates are
11 periodically adjusted in subsequent depreciation cases, the impact of any abnormal
12 retirements will be incorporated.

13

14 **Q191. What is the impact to customers if the IRM is approved but the Company does**
15 **not spend the full amount of projected capital expenditures?**

16 A191. As explained by Witness Foley, the Company will record a regulatory liability for
17 any over-recovery related to the IRM. The recording of any Regulatory Liability
18 will be reviewed through an IRM reconciliation proceeding, consistent with the
19 Commission's Order in Case No. U-21297. The Company will use account 254,
20 Other Regulatory Liabilities, for that purpose.

21

22 **Other Accounting Requests**

23 **Q192. What accounting treatment are you proposing for customer bill credits?**

Line
No.

1 A192. As discussed in detail by Witness Foley , the Company is proposing that bill credits
2 related to outages beyond the Company's control be deferred for future recovery.
3 Consistent with the proposal in Case No. U-20836, the Company will use account
4 182.3, Other Regulatory Assets, for that purpose. The Company proposes to
5 amortize the deferred amounts concurrent with their recovery in base rates.

6

7 **Q193. What accounting treatment are you proposing for storm costs?**

8 A193. As described by Witness Foley, the Company is requesting a storm restoration cost
9 sharing mechanism. I am requesting the use of account 182.3, Other Regulatory
10 Assets, and 254, Other Regulatory Liabilities, to record the refundable or
11 recoverable portion of any difference between actual storm costs and the base
12 amount approved in this case.

13

14 **Summary**

15 **Q194. Can you summarize what Commission approvals the Company is requesting?**

16 A194. In addition to the forecasted costs and revenues included herein, the Company is
17 requesting a continuation of the previously approved deferral treatment for Pension
18 expense, OPEB expense, LIA/RIA credits, TOD implementation costs, PERC
19 projects, and certain Charging Forward programs. I am also requesting approval to
20 use accounts 182.3 and 254 to record any under/over recovery from the storm cost
21 sharing mechanism.

22

23 **Q195. Does this complete your direct testimony?**

24 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

REBUTTAL TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF THERESA M. UZENSKI

Line
No.

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

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

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

9 A2. Yes.
10

11 **Purpose of Testimony**

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

13 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
14 other parties as follows. The absence of a discussion of other matters in my
15 testimony should not be taken as an indication that I agree with all other aspects of
16 intervenor testimony. More specifically, I provide rebuttal on the following topics:

17 • Michigan Public Service Commission (MPSC or Commission) Staff's (Staff)
18 adjustment to remove IT O&M costs associated with disallowed Level 2
19 programs in the amount of \$2.4 million is too high because it represents 100% of
20 the cost instead of DTE Electric's portion of a shared expense between DTE
21 Electric and other DTE affiliates.

22 • If shared asset capital projects (i.e., projects that are to be utilized by more than
23 one DTE Energy company) are disallowed by the Commission, then the related
24 shared asset revenue included in projected net operating income must be
25 reduced for the amounts that will not be billed to affiliated entities.

Line
No.

- 1 • Staff's disallowance of fleet vehicle capital expenditures should be rejected
- 2 because it was based on a misunderstanding of the total amount of expense and
- 3 utilization of only a portion of that total expense.
- 4 • The Attorney General's (AG) proposed disallowance of the vehicle fleet capital
- 5 expenditures should be rejected because the Company's forecast method is
- 6 more accurate than the use of a historical average proposed by the AG.
- 7 • The AG's proposed disallowance of office space updates and equipment should
- 8 be rejected because it disregards the Company's reasonable explanation and
- 9 support for the expenditures provided in discovery.
- 10 • Any disallowances of capital projects going in-service beyond the projected test
- 11 period should not have an impact on the revenue requirement because the cost
- 12 is offset by an AFUDC credit in projected net operating income and that alone
- 13 is not a reasonable basis to disallow capital project expense.
- 14 • The AG's proposed exclusion of the Ludington regulatory asset should be
- 15 rejected because the regulatory asset has been approved by the Commission to
- 16 address circumstances at an important generation asset.
- 17 • The AG's proposal to remove the \$3.9 million regulatory asset for Deferred
- 18 Incentive Compensation and replace it with a regulatory liability of \$6.8 million
- 19 should be rejected because the calculation is inaccurate and inconsistent with
- 20 the design of the approved mechanism. My testimony supports the correct
- 21 calculations based on actual 2022 and 2023 costs.
- 22 • Staff's proposed adjustments to certain benefits expenses based on the net
- 23 expense recorded in 2023 is incorrect. I support that the 2023 expenses should
- 24 be increased to reflect a normalized allocation of costs.

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- 1 • The proposal by AG-MNSC (Michigan Environmental Council, Natural
2 Resource Defense Council, Sierra Club, and Citizens Utility Board of
3 Michigan) to require DTE Electric to continue to explain its decision to
4 capitalize tree trimming expenses in its next rate case should be rejected. The
5 Company has previously explained its policy, and my rebuttal testimony
6 confirms that the Company complies with the accounting prescribed by the
7 Uniform System of Accounts (USoA).

8

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

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

11	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
12	A-37	BB1	Shared Asset Adjustment and O&M for Proposed
13			Disallowances
14	A-37	BB2	Projected Fleet Vehicle Purchases 2025
15	A-37	BB3	Incentive Plan Metrics

16

17 **Q5. Were these exhibits prepared by you or under your direction?**

18 A5. In general, yes, they were. However, Exhibit A-37 Schedule BB3 is copy of the
19 Company's 2021 Case No. U-20836 incentive compensation performance
20 gradients sponsored by Witness Cooper in that case.

21

22 **IT O&M**

23 **Q6. What O&M disallowance did Staff propose related to IT capital projects that**
24 **they propose be disallowed?**

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1 A6. Staff has reduced O&M by \$2.4 million related to IT capital projects that it proposes
2 be disallowed. Staff Witness Rogers explains this on page 6 of her direct testimony,
3 starting at line 6.
4

5 **Q7. Do you agree with these adjustments?**

6 A7. Company Witnesses Sharma and Hatsios address the prudence of the specific
7 projects. However, should the Commission decide to disallow the projects and
8 related O&M, then the O&M impact must be reduced by the amount not applicable
9 to DTE Electric. The \$2.4 million O&M cited by Staff is the amount supporting
10 all DTE Energy users of the assets. The actual IT O&M costs recorded at DTE
11 Electric are based on the bill down of costs from the DTE Energy Corporate
12 Services LLC, approximately 74% of the total, or \$1.8 million of the total \$2.4
13 million. Therefore, the portion of the O&M costs not related to DTE Electric is
14 \$0.6 million as shown on Rebuttal Exhibit A-37, Schedule BB1, line 18 column
15 (g).

16 **Revenue**

17 **Q8. What did the Company forecast for Shared Asset revenue?**

18 A8. As shown on my Exhibit A-13, Schedule C3, line 14, the Company forecasted \$63.5
19 million of revenue from shared assets such as building and information technology
20 with its affiliates. The assets are reflected in rate base for DTE Electric, but the
21 revenue requirement is reduced by the amount billed to DTE Energy affiliates for
22 their usage of the assets.
23

24 **Q9. What is the impact to Shared Asset revenue if the Commission disallows the**
25 **underlying assets?**

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1 A9. Since the projected revenue assumes the capital projects supported in the instant
2 case are approved, the revenue projection needs to be reduced for the impact of any
3 capital disallowances of shared assets. The reduction to shared asset revenue for
4 each project proposed for disallowance is shown in my Rebuttal Exhibit A-37,
5 Schedule BB1, column (f), for a total of \$1.8 million on line 18. If the Commission
6 disallows a capital project that is for a shared asset, then it must also remove the
7 revenue related to that asset from projected net operating income.

8

9 **Capital Expenditures**

10 **Q10. What disallowances related to vehicle fleet capital expenditures have been**
11 **proposed by the AG?**

12 A10. AG Witness Coppola, at lines 7 to 12 on page 54 of his direct testimony, proposes
13 disallowances of \$4.564 million and \$8.187 million for 2024 and 2025 capital
14 expenditures, respectively. This is based on comparing the Company's filed
15 request to an average of expenditures during 2021 to 2023.

16

17 **Q11. How do you respond to the AG's methodology to estimate projected costs?**

18 A11. I disagree with the AG's methodology. AG Witness Coppola asserts on page 53,
19 starting at line 17, through page 54 line 3, that the Company did not provide data
20 on the types of vehicles expected to be purchased in 2025. This is not accurate.
21 The Company provided a list of vehicle and equipment purchases planned for 2025
22 in response to Staff discovery question 4.3d. A copy is provided in my Rebuttal
23 Exhibit A-37, Schedule BB2. This exhibit confirms that the Company has specific
24 vehicle purchases planned for 2025. As described in my direct testimony, the
25 Company uses a life-cycle model to optimize the total cost of ownership and

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1 develop a replacement strategy. This is a more reasonable forecast methodology
2 than the simplistic historical average used by Witness Coppola. Therefore, the
3 Commission should reject his proposed disallowances and approve the Company's
4 projected capital expenditures for vehicle fleet.

5

6 **Q12. Did Staff propose a disallowance of fleet capital expenditures?**

7 A12. Yes. Staff Witness Boutet proposed a disallowance of \$2.84 million for the bridge
8 period and \$3.83 million for the test year on page 7, starting at line 3 of his direct
9 testimony. He explains that the adjustment is "based on the historical
10 underspending in 2023 in this category as well as evidence that the Company is
11 again on track to underspend in 2024." Witness Boutet comes to this conclusion
12 based on the list of vehicles purchased by the Company in 2023 shown on his
13 Exhibit S-12.6, which is what the Company understood was being requested. Page
14 8 of his exhibit shows the direct cost of the vehicle purchases as \$29.3 million.
15 Witness Boutet compared this to the Company's 2023 projection of \$32.8 million
16 for Vehicle Fleet and Maintenance on my Exhibit A-12, Schedule B5.8, line 1,
17 column (c) and logically, but incorrectly, assumed that the Company underspent its
18 forecast.

19

20 However, the Company's discovery response to STDE-4.3a, shown on his Exhibit
21 A-12.6, reflected only the direct purchase cost of vehicles (which is what the
22 Company understood was being requested) and did not include capital maintenance
23 costs or the internal labor costs allocated and capitalized as part of the cost of the
24 Company's vehicle fleet. The total actual capital expenditure for 2023 for vehicle
25 fleet was \$33.2 million and was provided in response to AG discovery question

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1 AGDE-3.130a. (See AG Witness Coppola's Exhibit AG-17, page 2.) Thus, there
2 was no underspending in 2023. The Company's projection for 2024 provided in
3 STDE 4.3b, and shown on Witness Boutet's Exhibit S-12.7, reflects the same
4 circumstance. It did not include capital maintenance, or the internal labor related
5 to the capitalized fleet vehicles. The complete forecast for 2024 is \$38.2 million
6 and is also shown in AGDE-3.130a (Exhibit AG-17, page 2). I am requesting that
7 the Commission reject Witness Boutet's proposed disallowances which were
8 triggered solely by the incorrect exclusion of capital maintenance and labor cost
9 components in the Company's response to Staff discovery STDE-4.3.

10

11 **Q13. What is the Attorney General's proposed disallowance for floor renovation**
12 **capital projects?**

13 A13. Starting at line 13 on page 50 of his direct testimony, AG Witness Coppola proposes
14 disallowances of capital expenditures totaling \$14.3 million for office space
15 updates and office equipment. On page 51, at line 3, he asserts the Company did
16 not provide clear answers as to why the expenditures were needed.

17

18 **Q14. How do you respond to Witness Coppola's proposed disallowance?**

19 A14. I disagree – both with the disallowance as well as the conclusion that the Company
20 did not provide clear answers. Witness Coppola is disregarding the information the
21 Company provided, which is included in his Exhibit AG-16. As can be seen on
22 pages 2 through 5 of his exhibit, the Company explained the rationale for the costs.
23 The Company had reduced its total office space by selling buildings and
24 terminating leases and then had to increase the number of workstations within that
25 smaller space to accommodate employees returning to the office after the

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1 pandemic. We moved from 2,000 reservable workstations to 4,100 workstations
2 assigned to each employee. Additional technology was required to enable more
3 video conferencing for employees in the office with employees working remotely.
4 Equipment was added as needed and meeting space was optimized. The conversion
5 of the open space in the downtown Detroit headquarters lobby was to accommodate
6 large groups that previously used leased space or facilities the Company no longer
7 owns. Regardless of whether he agrees with the Company's decisions, Witness
8 Coppola's assertion that the Company did not explain the expenditures is not
9 accurate. The Company maintains that its decisions regarding floor renovation
10 capital projects were reasonable, prudent, and justified. Thus, the Commission
11 should reject the AG's proposed disallowances of \$6.3 million for 2023 and \$8.0
12 million for 2024 (page 52, line 6).

13

14 **Q15. Did any of the parties to this case propose a reduction in rate base for projects**
15 **not going in service during the projected test period?**

16 A15. Yes. The AG and Association of Businesses Advocating Tariff Equity (ABATE)
17 have proposed disallowances of projects that are not in service during the projected
18 test period.

19

20 **Q16. What impact should a disallowance of projects that do not go into service**
21 **during the projected test period have on the Company's requested rate relief?**

22 A16. Such disallowances should not have any impact. As discussed in my direct
23 testimony, AFUDC is added to the asset being constructed with a corresponding
24 credit to the income statement. Including the credit to income from AFUDC offsets
25 the impact of including CWIP in rate base and therefore, projects that do not go

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1 into service during the projected test period have no impact on the Company's
2 revenue requirement and deficiency. To ensure that is the result, either the
3 proposed disallowances for projects not going into service should be excluded from
4 any reductions to rate base approved by the Commission, or a corresponding
5 adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of
6 the projects from approved rate base.

7

8 **Ludington Regulatory Asset**

9 **Q17. What is the Attorney General's recommended adjustment to working capital**
10 **related to deferred costs for the Ludington power generating facility?**

11 A17. On page 58, starting at line 7, AG Witness Coppola proposes that this regulatory
12 asset of \$9.9 million be removed from working capital until "the Commission
13 decides the appropriate amount of deferred costs that the Company should be
14 allowed to recover" because the dispute causing the costs is unsettled. He suggests
15 a return can then be "included with the deferred amount for the period of time the
16 recoverable portions of the net costs were outstanding."

17

18 **Q18. How do you respond to this proposed adjustment?**

19 A18. As will be detailed below, AG Witness Coppola has made a proposal that would
20 unreasonably take away the ability for the Company to cover, in a timely manner,
21 the financing costs related to costs incurred by the Company and recorded to a
22 regulatory asset that was approved for use by the Commission in Case No. U-21310
23 for costs necessary for the ongoing operation of a generation asset that is important
24 to the State of Michigan and a fundamental piece of clean energy advancement.

Line
No.

1 **Q19. How does AG Witness Coppola support the removal of the Ludington Plant**
2 **regulatory asset from working capital?**

3 A19. AG Witness Coppola indicates that there are still related replacement power issues
4 in Power Supply Cost Recovery (PSCR) cases that have not been resolved and the
5 litigation with Toshiba is also not resolved. Based on these unresolved issues, AG
6 Witness Coppola indicates that it is imperative that the Company not earn a return
7 on the deferred amounts until the Commission rules on the appropriate amount to
8 be recovered in rates.

9

10 **Q20. Do you agree that the reasons provided by AG Witness Coppola provide**
11 **sufficient justification to remove the Ludington Plant regulatory asset from**
12 **working capital?**

13 A20. I do not. AG Witness Coppola's proposal will require the Company to support the
14 financing of all costs incurred until final resolution in the Toshiba litigation. This
15 is not a reasonable proposition. Therefore, the Commission should reject the
16 recommendation to remove the balance from working capital.

17

18 **Q21. Is the Witness Coppola's position consistent with established practice for**
19 **regulatory assets?**

20 A21. No. It is not. Earning a return on a regulatory asset by including it in working
21 capital is an accepted regulatory practice and is consistent with the treatment of
22 other working capital financed by the Company. Regulatory assets are generally
23 included in working capital unless they have a separate recovery mechanism. None
24 of the costs recorded to the Ludington regulatory asset are being recovered in the
25 PSCR or other mechanism.

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1 **Q22. Does including costs associated with the Ludington repairs in the regulatory**
2 **asset and as working capital harm customers?**

3 A22. No, it does not. Requiring the utility to bear the financing costs during the pendency
4 of the litigation against Toshiba would be unfair and would hinder its ability to
5 accomplish the projects needed to remedy Toshiba's defects. The regulatory asset
6 ensures that the utility can accomplish the necessary work at the same time it is
7 prosecuting the lawsuit against Toshiba for the benefit of customers. Any costs
8 which are not ultimately recovered from Toshiba will be fully reviewed by the
9 Commission after the conclusion of the lawsuit. The regulatory asset, and the
10 accounting treatment used by the Company in this case is appropriate.

11

12 **Incentive Compensation Regulatory Asset**

13 **Q23. What is the Attorney General's recommended adjustment to working capital**
14 **related to deferred incentive compensation?**

15 A23. AG Witness Coppola discusses this starting at line15 on page 58 of his direct
16 testimony. The Company projected a balance of \$3.9 million in a regulatory asset,
17 representing the difference between the amount of incentive compensation related
18 to operating metrics approved in Case No. U-20836, and the forecasted expense
19 based on achieving the targeted results. Witness Coppola argues (1) there is no
20 recoverable balance for 2022, (2) the balance for 2023 is a regulatory liability of
21 \$6.8 million, and (3) it is premature to establish a regulatory asset for anticipated
22 results in 2024. He also argues, on page 61, line 15, that the liability balance should
23 be amortized over five years. As stated in Witness Coppola's testimony at the top
24 of page 62, the difference in his proposed regulatory liability and the Company's
25 proposed regulatory asset is a reduction in working capital of \$10 million.

Line
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1 **Q24. What does the AG propose the balance should be for deferred incentive**
2 **compensation?**

3 A24. AG Witness Coppola suggests the balance should be a liability and explains his
4 calculation of the incentive compensation regulatory liability on page 61 of his
5 direct testimony, starting at line 1. The calculations for 2023 are shown on his
6 Exhibit AG-20. In column (b) of Exhibit AG-20, Witness Coppola starts with the
7 incentive compensation forecasted in DTE Electric's rate case, Case No. U-20836.
8 He then applies a percentage of 2023 measures achieved in column (c) to determine
9 the expense he claims as the amount eligible for recovery, which is shown in
10 column (d) and totals \$5.943 million on line 6. He further compares that amount
11 to the base shown on line 5, resulting in a difference of \$6.792 million on line 7.
12 Witness Coppola suggests that this is the appropriate amount for a regulatory
13 liability. He further suggests that the liability be amortized over five years with a
14 credit to O&M of \$1.358 million as shown on line 8. This results in a 2025 ending
15 liability balance of \$5.434 million on line 9. The average balance of \$6.113 million
16 is shown on line 10.

17

18 **Q25. Do you have any concerns with the AG's calculations?**

19 A25. Witness Coppola's calculation contains two flaws. The first problem is the amount
20 he uses on Exhibit AG-20 in column (b). He used a forecast based on the estimated
21 expense in the (then projected) twelve-months ending October 2023 from a prior
22 Electric rate case (Case No. U-20836, filed January 21, 2022) instead of the actual
23 expense incurred during 2023. The mechanism design (like other similar tracker
24 mechanisms) compares actual expense incurred to a pre-determined base amount.
25 The Order in Case No. U-20836, page 301 states: "In addition, the Commission

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1 authorizes DTE Electric to implement a two-way tracker mechanism, which will
2 require refunds to customers if the 60% target level is not achieved or will allow
3 the company to recover additional funds if it exceeds the 60% target level, up to a
4 maximum of 100% target level. DTE Electric shall record the over- or under-
5 recovery, compared to the 60% base, in a regulatory asset or regulatory liability to
6 be included in the company's next general electric rate case." The correct starting
7 point for the calculation is actual 2023 incentive compensation expense related to
8 operating metrics, capped at 100% of the target.

9

10 **Q26. What is the second flaw in Witness Coppola's calculation?**

11 A26. As shown on his Exhibit AG-20, Witness Coppola is assuming performance results
12 in column (c) of 28.0%. These figures come from his Exhibit AG-21, page 2 and
13 are based on the number of metrics at Target or better. This calculation is flawed
14 because it assumes all the operating metrics underlying the incentive compensation
15 plan are based on whether performance Targets were met or not met (i.e., binary).
16 In fact, a performance weighted average is the basis for the actual incentive
17 compensation plan payouts that recognizes there are gradients between the
18 Threshold and Maximum performance levels, as more fully explained by Company
19 Witness Fix, rather than Witness Coppola's simplistic binary method. The
20 recognition of the gradients in performance can be seen on Company Witness
21 Cooper's Exhibit A-21, Schedule K4 in Case No. U-20836 (copy provided in
22 Rebuttal Exhibit A-37, Schedule BB3) and on Witness Fix's Exhibit A-21,
23 Schedule K2 in the instant case. Applying the weighting used in the plan design
24 results in the actual 2023 outcome ranging from 33.6% to 52.7% as shown on
25 Witness Fix's Rebuttal Exhibit A-35, Schedule Z1, line 47. This equates to expense

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1 of \$5.987 million. This amount is shown on my Exhibit A-13, Schedule C5.10.1,
2 line 2, column (c). Comparing this to the base amount of \$12.735 million results
3 in a regulatory liability for 2023 of \$6.748 million shown on Exhibit A-13,
4 Schedule C5.10.1, line 4, column (c).

5

6 **Q27. What is your response to AG Witness Coppola's conclusion that there is no**
7 **recoverable balance related to deferred incentive compensation in 2022?**

8 A27. I disagree. The Commission's Order authorizing the deferral of certain incentive
9 compensation in Case No. U-20836 was issued on November 18, 2022 and the
10 Company recorded a deferral related to December 2022 costs. On page 60, starting
11 at line 11, Witness Coppola argues that based on his calculation of results achieved
12 compared to the target, the Company should have accrued a regulatory liability
13 instead of an asset and effectively disregards the accrual because the amount "was
14 de minimis." However, for the same reasons I explained related to the 2023
15 balance, Witness Coppola's assumptions for the 2022 balance are also flawed. He
16 states on page 60, at line 11 that the Company achieved only 52% of its target in
17 2022 (below the 60% base). Again, this assumed the targets are equally weighted.
18 On a weighted basis, the Company achieved over 80% of its operational target in
19 2022, as shown on his Exhibit A-21, row 47. Since this was above the baseline of
20 60%, the Company recorded a regulatory asset of \$856,000, shown on my Exhibit
21 A-13, Schedule C5.10.1 line 4, column (b). In response to discovery question
22 AGDE-3.128a, this amount was reduced by \$106,000 for a revised balance of
23 \$750,000.

Line
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1 **Q28. What is the appropriate amount of the deferral of incentive compensation for**
2 **2022 and 2023?**

3 A28. Adding the 2022 regulatory asset of \$750,000 to the 2023 regulatory liability of
4 \$6.748 million results in a net regulatory liability of \$5.998 million as of December
5 31, 2023.

6
7 **Q29. What is the resulting annual amortization expense?**

8 A29. If the Commission agrees with the AG's proposal to amortize the regulatory
9 liability over five years, the annual credit to O&M should be \$1.200 million (instead
10 of the \$1.358 million proposed by Witness Coppola). This would result in a 2025
11 ending balance of \$4.799 million and an average liability in working capital of
12 \$5.398 million. This is a \$9.282 million reduction in working capital compared to
13 the Company's filed position.

14

15 **Benefits Expense Rates**

16 **Q30. Did Staff propose adjustments to projected benefits costs?**

17 A30. Yes. Staff Witness Rueckert proposed a reduction to benefits. I will address the
18 impact of his expense assumptions on employee savings plan expense, general
19 benefits, and benefit administration fees. Witness Rueckert's proposed benefits
20 expenses are calculated on his Exhibit S-15.3. He calculated his projections for the
21 Employee Saving Plan, General Benefits and Benefits Administration Fees by
22 applying an assumed rate of change to 2023 actual costs. The 2023 figures are the
23 amount of expense recorded in O&M, net of amounts capitalized. The expense
24 portion for 2023 was 54.6% for the Employee Savings Plan, 58.7% for General
25 Benefits, and 54.8% for Benefits Administration Fees.

Line
No.

1 **Q31. Should the 2023 expense portion assumptions used by Staff Witness Rueckert**
2 **be applied to projected benefit costs in 2024 and 2025?**

3 A31. No. Given the financial challenges experienced by the Company in 2023, non-
4 recurring reductions to O&M were made during 2023. This resulted in a higher
5 proportion of related benefits to be capitalized than in a normal year. The Company
6 is returning to a more standard level of O&M in 2024 and beyond. Therefore, a
7 better forecast of benefits expense net of amounts capitalized would be based on
8 the expense percentages from 2022. Company Witness Fix supports Employee
9 Savings Plan expenses on his Rebuttal Exhibit A-35, Schedule Z2, and Company
10 Witness Hooper supports General Benefits and Benefit Administration Fees
11 expenses on his Rebuttal Exhibit A-36, Schedules AA3 and AA4. Applying an
12 expense rate based on 2022 data normalizes (increases) the three benefits expense
13 items by approximately \$3.6 million.

14

15 **Tree Trim Capitalization**

16 **Q32. What do the AG and MNSC (AG-MNSC) propose regarding the capitalization**
17 **of vegetation management (tree trimming) costs?**

18 A32. AG-MNSC Witness Alvarez discusses the accounting for vegetation management
19 starting on page 34 of his direct testimony. On page 37, line 1, Witness Alvarez
20 states, “I conclude that the only permitted capitalization of vegetation management
21 spending is in the initial construction of brand-new overhead distribution line. Any
22 other capitalization of tree trimming expense is an unequivocal violation of the
23 Michigan USOA.” At line 19 on page 38 he proposes that the Commission should
24 require DTE Electric to “explain the legitimacy of its decision to capitalize tree
25 trimming expenses for distribution capital programs” in its next rate case.

Line
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1 **Q33. How do you respond to Witness Alvarez's proposal?**

2 A33. I disagree. In Case No. U-21297, the Company explained that its accounting
3 policies for tree trimming comply with the requirements of the USoA. Another
4 review in a future rate case is unnecessary. Furthermore, Witness Alvarez's
5 interpretation of the USoA is flawed. At the top of page 37 he concludes, without
6 any basis, that vegetation management can only be capitalized for the initial
7 construction of brand-new overhead distribution line. This suggests that any
8 succeeding clearing is maintenance expense, even if the clearing is done to enable
9 construction work, which is incorrect.

10

11 **Q34. How is Witness Alvarez's interpretation of the USoA flawed?**

12 A34. Witness Alvarez ignores the USoA's definition of Maintenance included within the
13 Operating Expense Instructions. That definition states that maintenance expense
14 includes "Work performed specifically for the purpose of preventing failure,
15 restoring serviceability or maintaining life of plant." It also states that expense
16 includes "Replacing or adding minor items of plant which do not constitute a
17 retirement unit." Maintenance expense, by definition, is related to sustaining
18 existing assets. The tree trimming activities capitalized by the Company relate to
19 the installation of new assets (which *do* constitute a retirement unit), not to
20 maintaining existing assets.

21

22 **Q35. Which items from the USoA does Witness Alvarez cite?**

23 A35. Starting at line 4 on page 35 of his direct testimony, Witness Alvarez discusses that
24 the USoA description of account 365, Overhead Conductors and Devices, allows
25 for the capitalization of the initial cost of tree trimming. His conclusion assumes

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1 that the capitalization of trimming is only applicable to the first installation of
2 electric lines, but not to the poles to which those lines are attached, or any other
3 adjacent assets. However, it cannot be expected that every possible type of cost be
4 listed in the description of each account. The USoA General Instruction No. 6,
5 Item Lists, says the following: “Lists of *items* appearing in the texts of the accounts
6 or elsewhere herein are for the purpose of more clearly indicating the application
7 of the prescribed accounting. The lists are intended to be representative, but not
8 exhaustive.” Also, Witness Alvarez refers to USoA Plant Instruction No. 9.

9

10 **Q36. What is Plant Instruction No. 9?**

11 A36. Plant Instruction No. 9 in the Electric USoA discusses the capitalization of
12 equipment which says, in part, “Also include those costs incurred with the first
13 clearing and grading of land and rights-of-way.” Starting at line 6 on page 35,
14 Witness Alvarez cites this sentence, asserting that this instruction defines “initial
15 cost” as used within the description of Account 365. However, the term “initial
16 cost” is not mentioned in the USoA discussion of equipment.

17

18 Regardless, the USoA does say that the cost of equipment shall include “expenses
19 incurred by the utility in unloading and placing the equipment in readiness to
20 operate.” Tree trimming required to install capital assets is clearly an expense
21 incurred to place equipment in readiness to operate. Thus, Witness Alvarez’s
22 conclusion that capitalization of tree trimming is restricted to the initial installation
23 of brand-new overhead distribution line is not supported by a full reading of the
24 USoA and should be rejected by the Commission.

Line
No.

1 **Q37. How does the Commission's Order in Case No. U-17767 inform the accounting**
2 **for tree trimming costs?**

3 A37. Witness Alvarez references Case No. U-17767 starting at the top of page 36 of his
4 direct testimony. In that case, the Company requested capital treatment for its
5 Enhanced Vegetation Management Program (EVMP) which expanded the
6 clearance area when trees are trimmed. The Commission concluded the expansion
7 of the clearance area should be accounted for as maintenance expense as it was not
8 a first clearing. Witness Alvarez suggests this should inform the accounting for
9 tree trim activities completed in conjunction with capital projects. Once again, he
10 has disregarded the full context of the issue.

11

12 **Q38. Can you provide more detail regarding the Company's EVMP?**

13 A38. As supported by Company Witness Pogats in Case No. U-17767, the EVMP was
14 initiated to help prevent outages and improve reliability. He stated in his direct
15 testimony: "With this enhanced practice, all vegetation that has the ability to grow
16 into or overhang the power line within five years is removed. Critical portions of
17 circuits, such as the area between the substation and the first recloser, will be
18 targeted for this method of clearance to maximize the impact of the investment¹."
19 The EVMP investment costs at issue were related to an improvement in
20 maintenance trimming that was not incurred to enable the installation of capital
21 assets. Rather, the program was intended to reduce the need to replace assets by
22 avoiding damage resulting from trees.

¹ MPSC Case No. U-17767 at 4T 365

Line
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1 **Q39. What did the Commission's Order in Case No. U-17767 say regarding tree**
2 **trim costs incurred in conjunction with capital work?**

3 A39. The Commission did not opine on the capitalization policy of tree trim as it relates
4 to the installation or replacement of capital assets in Case No. U-17767. Its Order
5 addressed only the accounting for the EVMP, a maintenance program. Therefore,
6 Witness Alvarez's argument that tree trimming costs related to capital work were
7 deemed to be maintenance expense by the Commission is inaccurate and should be
8 rejected.

9

10 **Q40. What would be the impact to the revenue requirement if the Commission**
11 **required all tree trimming costs to be expensed as O&M?**

12 A40. The issue raised by AG-MNSC is one of accounting classification, not prudence.
13 Therefore, if the Commission orders that all tree trimming costs associated with
14 capital work must be expensed as incurred, then the Commission should provide an
15 increase to O&M to reflect the change.

16

17 **Q41. Does this conclude your rebuttal testimony?**

18 A41. Yes, it does.

1 JUDGE WALLACE: All right. Moving on,
2 Mr. Christinidis.

3 MR. CHRISTINIDIS: Yes, your Honor. The
4 Company's next witness is Margaret E. Guillaumin.
5 Ms. Guillaumin sponsored Qualifications and Revised
6 Direct Testimony of Margaret E. Guillaumin, consisting of
7 a cover sheet and 134 pages of questions and answers.
8 Ms. Guillaumin also sponsored rebuttal testimony,
9 consisting of a cover sheet and 29 pages of questions and
10 answers. Ms. Guillaumin sponsored direct Exhibits A-6
11 Schedule F1, Exhibit A-6 Schedule F2, Exhibit A-12
12 Schedule B5.1, Exhibit A-12 Schedule B5.1.1, Exhibit A-13
13 Schedule C5.1, Exhibit A-13 Schedule C5.4, and Exhibit
14 A-13 Schedule C5.5. She also sponsors associated with
15 her rebuttal testimony Exhibit A-34 Schedules Y1 and Y2.
16 So with that, the Company would move to bind in the
17 Qualifications, Revised Direct Testimony, and Rebuttal
18 Testimony of Margaret E. Guillaumin, and move the
19 admission of the aforementioned exhibits and schedules.

20 JUDGE WALLACE: Thank you,
21 Mr. Christinidis. Is there any objection to binding in
22 the revised direct testimony of Ms. Guillaumin?

23 Hearing none, the testimony is bound in.
24 Is there any objection binding in the
25 rebuttal testimony of Ms. Guillaumin?

1 Hearing none, the rebuttal testimony is
2 bound in.

3 Any objection to the exhibits or
4 schedules associated with those exhibits identified by
5 Mr. Christinidis?

6 Hearing none, we will admit those
7 exhibits at the close of binding in the Company's case.

8 (Testimony bound in.)

9 - - -

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25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
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
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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
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- 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
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- 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
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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
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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

13

Factor (POF), and Random Outage Factor (ROF) to monitor overall unit

14

performance. EAF is equal to 100 minus the POF minus ROF. Equivalent

15

availability is equal to total possible megawatt-weeks minus planned outage

16

megawatt-weeks minus random outage megawatt-weeks (including full and partial

17

derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks

18

are calculated by multiplying the net demonstrated capacity of the unit by the weeks

19

in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to

20

the equivalent number of weeks in the time-period that the unit is not available due

21

to scheduled maintenance multiplied by the capacity that is out of service. Random

22

outage megawatt-weeks is the number of weeks of unit unavailability caused by an

23

outage or derate that is not planned or scheduled, multiplied by the capacity that is

24

out of service.

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
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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

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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
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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
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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
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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
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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
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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

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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

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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

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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
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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

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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

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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
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- 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
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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
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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
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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
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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

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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

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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

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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

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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

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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

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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
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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

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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

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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

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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

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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,

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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

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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

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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

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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

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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
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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

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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

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- 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
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- 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
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- 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
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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
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- 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
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- 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
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- 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

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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 NOx 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
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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
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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
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- 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

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- 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

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- 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

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- 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

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- 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.

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- 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

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- 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

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- 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,

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- 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

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- 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

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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

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- 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

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- 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

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- 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.

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- 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

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- 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

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- 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
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- 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

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- 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.

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- 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

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- 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

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- 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

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- 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.

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- 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

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- 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

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- 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.

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- 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

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- 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.

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- 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 NOx 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

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- 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

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- 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.

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- 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
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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

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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

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- 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

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- 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).

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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

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- 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

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- 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

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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

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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

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- 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

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- 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

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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

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- 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.

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- 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

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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,

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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

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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

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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?**

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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

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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"

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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

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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 Foley, memberships in industry associations provide
17 the Company access to benchmarking/best practices, research, and networking
18 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

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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

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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

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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.

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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

REBUTTAL TESTIMONY

OF

MARGARET E. GUILLAUMIN

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MARGARET E. GUILLAUMIN

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

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

6

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

9 A2. Yes.
 10

11 **Purpose of Testimony**

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

13 A3. The purpose of my rebuttal testimony is to correct errors and rebut unjustified
 14 recommendations for disallowances of capital projects as recommended by
 15 multiple witnesses that provided direct testimony in the instant case. These
 16 witnesses include:

- 17 • Attorney General (AG) Witness Coppola;
- 18 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
- 19 York;
- 20 • Michigan Public Service Commission (MPSC) Staff (Staff) Witnesses
- 21 Kindschy and DeCooman.

22

23 I will also address Great Lakes Renewable Energy Association (GLREA) Witness
 24 Richter's request for a battery energy storage system (BESS) siting analysis.

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1 The absence of a discussion of other matters in my rebuttal testimony should not
2 be taken as an indication that I agree with all other aspects of any intervenor's
3 testimony.

4

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

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

7 Exhibit Schedule Description

8 A-34 Y1 BWEC Conference Room Building Discovery Responses

9 STDE-2.5, STDE-3.6b-d, STDE-10.1a-c

10 A-34 Y2 Power Generation 2023-2024 Non-Routine Capital

11 Expenditure Projections and Actuals from Discovery

12 Responses STDE-2.1a and STDE-2.1b

13

14 **Q5. Were these exhibits prepared by you, under your direction, or are you**
15 **otherwise familiar with their contents as part of your job responsibilities?**

16 A5. Yes.

17

18 **Q6. How is your rebuttal testimony organized?**

19 A6. My rebuttal testimony consists of the following ten (10) parts:

20 Part I The Company's routine capital maintenance projections for Belle River
21 and Greenwood Power Plant are based on specific approved and justified
22 projects. This is in contrast to the AG witness's use of multi-year
23 historical averages of total project spending levels to support his
24 generalized disallowance recommendations

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- 1 Part II The Blue Water Energy Center (BWEC) Conference Room Building
2 project is cost-effective and adequately supported
- 3 Part III The Company's newly-available actual capital expenditure data for
4 November 2023 through April 2024 does not warrant a disallowance as
5 proposed by Staff
- 6 Part IV Staff's assignment of cost estimate class accuracy range factors to the
7 Company's routine capital projects is inappropriate in its application and
8 is driving flawed disallowance recommendations
- 9 Part V The Company's black start projects are justified, and the Company took
10 balanced, reasonable, and necessary steps to be transparent while
11 protecting security sensitive information in this instant case
- 12 Part VI Staff's recommended reductions on Trenton Channel BESS non-contract
13 spend projections are not well-supported
- 14 Part VII ABATE's proposed disallowance related to River Rouge
15 Decommissioning based on minor paperwork differences is unwarranted
- 16 Part XIII The Company appropriately calculated overheads on the Slocum Battery
17 Pilot
- 18 Part IX The Trenton Channel Seawall project is worthy of recovery in the instant
19 case
- 20 Part X GLREA's request for an electrical distribution system-connected BESS
21 analysis is unnecessary

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1 **Part I – The Company’s routine capital maintenance projections for Belle River and**
 2 **Greenwood Power Plant are based on specific approved and justified projects. This**
 3 **is in contrast to the AG witness’s use of multi-year historical averages of total**
 4 **project spending levels to support his generalized disallowance recommendations**

5

6 **Q7. What does AG Witness Coppola recommend with respect to the Company’s**
 7 **projected routine capital expenditures for its Belle River and Greenwood**
 8 **Power Plants?**

9 A7. Witness Coppola recommends removal of \$30.1 million¹ of projected 2024-2025
 10 routine capital expenditures. His \$30.1 million recommended adjustment is
 11 comprised of \$13.3 million of 2024 capital expenditures at Belle River Power Plant
 12 and \$16.8 million total in 2024-2025 capital expenditures at Greenwood Power
 13 Plant.

14

15 **Q8. What is the basis of Witness Coppola’s proposed removal adjustment of Belle**
 16 **River Power Plant and Greenwood Power Plant routine capital expenditures?**

17 A8. Witness Coppola compares the Company’s 2024 and 2025 total projected routine
 18 capital expenditures for the Belle River and Greenwood Power Plants against an
 19 average of the last three years of actual project expenditures for these plants. He
 20 then applies inflation to his historic average and indicates project funding levels
 21 above the inflated historic averages should be removed from the forecasted capital
 22 expenditures². Witness Coppola makes these disallowance recommendations
 23 without any evaluation of the Company’s justified and internally approved projects

¹ Witness Coppola DT, page 36, lines 13-14 (\$8.585m in 2024; \$8.223m in 2025) and page 37, lines 1-2 (\$13.270m in 2024).

² Witness Coppola DT, page 36, lines 9-14 and page 36, line 15 through page 37, line 2.

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1 for these two power plants. He apparently determines that historical plant project
2 funding levels should set a limit for future funding levels despite equipment
3 condition, changing circumstances, and continuing electrical system reliance on
4 these power plants.

5

6 **Q9. How do you respond to Witness Coppola's use of historical spending averages**
7 **to establish the next two years of routine capital maintenance at the Belle River**
8 **and Greenwood Power Plants?**

9 A9. The Company disagrees with Witness Coppola's approach. DTE Electric does not
10 use historical spending averages to establish the next two years of routine capital
11 maintenance at its power plants. The level of capital project work needed, justified,
12 planned, and approved is required to maintain safe, reliable, and environmentally
13 compliant future plant operations. Using historical averages ignores the specific
14 work necessary, including increased project work expected due to planned outage
15 schedules. These projects include the 2024 and 2025 capital projects listed on
16 Exhibit A-12, Schedule B5.1, pages 6 and 7 for Belle River and Greenwood Power
17 Plant that exceed \$1 million.

18

19 **Q10. What is requiring the Belle River and Greenwood Power Plants' planned**
20 **routine capital maintenance expenditures to exceed the 2021-2023 average**
21 **amount?**

22 A10. In the 2021-2023 timeframe utilized by Witness Coppola to establish his average
23 historical spending levels, Belle River Power Plant only had one major maintenance
24 outage and Greenwood Power Plant had a partial maintenance outage. For 2024
25 and 2025 in the instant case, two major maintenance outages are planned for Belle

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1 River Power Plant and one full major maintenance outage for Greenwood Energy
2 Center. The historical spending level identified by Witness Coppola does not
3 support execution of the identified, justified, and approved capital projects planned
4 for completion during these outages in 2024 and 2025.

5

6 **Q11. Why are planned outage schedules an important consideration for projected**
7 **routine capital maintenance?**

8 A11. The Company's steam generation units are typically taken offline at least once
9 every 3-5 years for several months in order to perform major maintenance. During
10 these planned major maintenance outages, large capital projects are completed to
11 keep the units running safely, reliably, efficiently, and environmentally compliant
12 until the next major maintenance. This results in variability in annual spend levels,
13 with some years being much higher than others, based on the amount and
14 complexity of required power plant work, not by calendar year or funding utilized
15 in past years.

16

17 **Q12. Are there other reasons that can cause routine capital expenditures to be**
18 **higher in one year compared to an average historical annual value?**

19 A12. Every major maintenance outage includes differing work activities and supportive
20 capital projects. Project scope and required funding levels can increase greatly
21 when major work on the turbine-generator and/or boiler key components is
22 required. For example, the Company is replacing the low pressure (LP) turbines
23 on Belle River Unit 2 in 2024 and Greenwood Unit 1 in 2025 due to industry-wide
24 concerns with stress corrosion cracking as further discussed in my revised direct
25 testimony, pages 88-89 and 102. This turbine maintenance is routine in nature but

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1 infrequent as evidenced by this being the first time the LP turbines have been
2 replaced in the history of these plants. The LP turbine rotors were original
3 equipment and installed approximately 40 years ago. In total, each turbine
4 replacement project exceeds \$20 million. Infrequent but routine in nature, large
5 capital maintenance projects, such as the replacement of the LP turbines, lead to
6 lumpy annual capital expenditure levels. Witness Coppola fails to acknowledge
7 this expected variability when he recommends limiting future capital project
8 funding approvals based on the funding required during the 2021-2023 period.

9

10 **Q13. What should the Commission find with respect to Witness Coppola's**
11 **recommendation to remove portions of the planned capital routine**
12 **maintenance at the Belle River and Greenwood Power Plants simply based on**
13 **historical average spend?**

14 A13. The Commission should find the Company's use of specific project plans is
15 appropriate and required. Witness Coppola's use of historical averages to limit
16 projected routine capital expenditures for 2024 and 2025 is not prudent or logical
17 and his recommended \$30.1 million disallowance, which includes no engineering
18 analysis, should carry no weight.

19

20 **Part II – The Blue Water Energy Center (BWEC) Conference Room Building**
21 **project is cost-effective and adequately supported**

22

23 **Q14. What does ABATE Witness York recommend with respect to the Company's**
24 **projected capital expenditures for the BWEC Conference Room Building**
25 **project?**

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1 A14. Witness York recommends removal of \$3.3 million of projected 2024 capital
2 expenditures for the BWEC Conference Room Building project³.

3

4 **Q15. What is the basis of Witness York's proposed disallowance of BWEC**
5 **Conference Room Building project capital expenditures?**

6 A15. Witness York argues the Company has not adequately justified the cost or necessity
7 of the new conference room building and questions why adequate office space to
8 support site workforce during routine and major maintenance activities was not
9 included in the original design of the site⁴.

10

11 **Q16. Has the Company provided additional justification for the necessity of the**
12 **BWEC conference room building after its need was previously questioned?**

13 A16. Yes. In response to the December 1, 2023, Commission Order from the last rate
14 case, Case No. U-21297, further explanation was provided for the project in my
15 revised direct testimony, pages 117-118 in the instant case. This explanation
16 describes the need for additional workspaces during routine and major maintenance
17 activities because a high number of support personnel are onsite during this time.
18 All Company power plants have either constructed or repurposed available space
19 over the years to create large meeting spaces to accommodate workforce surges
20 during routine and major outages or construction activities. In addition, it was
21 explained that this building was not required during initial construction of the plant
22 because short-term rental trailers were utilized by the project construction firm,
23 Kiewit, for the purpose of hosting and onboarding the large workforce during
24 project construction.

³ Witness York DT, page 25, line 18 through page 26, line 3.

⁴ Witness York DT, page 25, line 20 through page 26 line 3.

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1

2 **Q17. Has the Company provided justification supporting the cost-effectiveness of**
3 **adding the BWEC conference room building?**

4 A17. Yes. Exhibit A-34, Schedule Y1 includes several discovery responses related to
5 the BWEC Conference Room building. Included in the responses is an analysis of
6 the BWEC Conference Room Building project versus other options including
7 purchasing and renting trailers. This analysis indicates that the new conference
8 room project will save the Company \$10+ million over the life of the plant as
9 compared to purchasing and renting trailers to support plant needs.

10

11 **Q18. What should the Commission find with respect to Witness York's**
12 **recommendation to remove projected 2024 capital expenditures for the**
13 **BWEC Conference Room Building project?**

14 A18. The Commission should find the Company properly supported the cost
15 effectiveness and necessity of the BWEC Conference Room Building project in
16 revised direct testimony and discovery responses in the instant case. Witness
17 York's recommendation to disallow \$3.3 million of project expenditures associated
18 with the BWEC Conference Room Building should be rejected.

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1 **Part III – The Company’s newly-available actual capital expenditure data for**
2 **November 2023 through April 2024 does not warrant a disallowance as proposed by**
3 **Staff**

4
5 **Q19. Based on monthly actual capital expenditures that post-date the data relied**
6 **upon to develop the instant case, what do Staff Witnesses Kindschy and**
7 **DeCooman recommend?**

8 A19. For routine capital projects, Staff Witness Kindschy recommends a \$21.3 million
9 reduction in capital project expenditures based on the difference between
10 November 2023 through April 2024 actual expenditures and the projected amounts
11 included in my exhibits⁵.

12
13 Similarly, for non-routine capital projects, Staff Witnesses Kindschy and
14 DeCooman collectively recommend a \$5.1 million reduction to capital
15 expenditures. The \$5.1 million reduction includes Witness Kindschy’s review of
16 lines 1-18 of Exhibit A-12, Schedule B5.1, page 2, in which she identifies \$0.6
17 million of reduction for 2023 expenditures and \$3.1 million of reduction for 2024
18 expenditures⁶. Also included in the \$5.1 million is Witness DeCooman’s
19 recommended \$1.4 million reduction to 2023 expenditures on the Company’s
20 blackstart projects lines 37-39 of Exhibit A-12, Schedule B5.1, page 2⁷.

21
22 **Q20. Does the fact that there is a difference between the *monthly* forecast for capital**
23 **spend levels in exhibits compared to the actual spending levels for November**

⁵ Witness Kindschy DT, page 7, line 14 through page 8, line 2.

⁶ Witness Kindschy DT, page 6, lines 16-19.

⁷ Witness DeCooman DT, page 8, lines 19-21.

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1 **2023 through April 2024 justify Witness Kindschy's and Witness DeCooman's**
2 **disallowance recommendations?**

3 A20. No. The variance between exhibit and actual project spends for these short few
4 months is not a proper metric for measuring the performance of project execution,
5 nor an adequate projection of final project results. Those referenced differences
6 evidence nothing with regard to reasonableness and prudence of the projects.
7 Capital projects are managed on a total beginning-to-end basis with monthly
8 estimates developed to track general project evolution and annual total budget
9 targets. Monthly work scope plans and associated spend are developed at the start
10 of the project and updated periodically throughout the project timeline. There can
11 be monthly timing variances within the project execution that shift spend between
12 months across the duration of the project. Timing variances mean work has
13 completed or will be completed sooner or later than initially forecasted. The
14 Company expects the portfolio of projects to meet the overall projected spend as
15 represented in this instant case.

16

17 **Q21. How are capital projects measured?**

18 A21. Capital projects are measured against the total project scope, the planned schedule,
19 and the total funding level requested in the project approval documents. The end
20 result of scope and cost are important, not the day-by-day or month-by-month
21 journey taken to reach project completion.

22

23 **Q22. Following Witness Kindschy's and Witness DeCooman's analyses of monthly**
24 **expenditure variance, what would one find if all the non-routine capital**
25 **project forecasts included in Exhibit A-12, Schedule B5.1, page 2 were**

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1 **compared to the actual expenditures for the period November 2023 through**
2 **April 2024, instead of the partial subset of line items Witness Kindschy and**
3 **Witness DeCooman chose?**

4 A22. The Company's non-routine Power Generation expenditures for all the non-routine
5 projects for November 2023 through April 2024 are \$123.6 million, which exceeds
6 the \$109.3 million projected in Exhibit A-12, Schedule B5.1, page 2 for those
7 months in the instant case. Please refer to the rebuttal Exhibit A-34, Schedule Y2
8 for additional details. Based on following Witness Kindschy's and Witness
9 DeCooman's approach, those monthly expenditure variances alone would justify a
10 positive adjustment, with the Company's non-routine capital expenditures needing
11 to be increased by \$14.4 million in the instant case.

12

13 **Q23. What should the Commission find with respect to Witness Kindschy's and**
14 **Witness DeCooman's use of monthly capital spend variances to justify \$26.4**
15 **million⁸ of reductions to the Company's projects?**

16 A23. The recommendations to disallow project funding based on recent actual monthly
17 project spends should be disregarded. Just because a variance between forecast and
18 actual data can be found on a recent and short-term basis does not mean that the
19 projects are over-funded or are not being executed properly. The total result of a
20 project is the proper basis for scrutiny, not the day-by-day or month-by-month
21 journey of project planning and execution. Additionally, selection of only a subset
22 of projects in which the total actual spend is lower than the forecast is not a balanced
23 approach and should therefore be rejected.

⁸ The \$26.4 million of reductions is comprised of \$21.3 million of routine capital expenditures and \$5.1 million of non-routine capital expenditures.

Line
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1 **Part IV – Staff’s assignment of cost estimate class accuracy range factors to the**
2 **Company’s routine capital projects is inappropriate in its application and is driving**
3 **flawed disallowance recommendations**

4

5 **Q24. What is the Association for the Advancement of Cost Engineering (AACE)**
6 **International Cost Estimate Classification System and how has Staff Witness**
7 **Kindschy utilized it in the instant case?**

8 A24. The International Cost Estimate Classification System focuses primarily on the
9 level of project definition with secondary consideration on the purpose of the
10 estimate, typical estimating method, expected accuracy range, and the expended
11 effort of the estimate compared to the final project estimate. The AACE Cost
12 Estimate Classification System is referenced by Staff Witness Kindschy and
13 utilized as her stated source for recommending a 15% capital project funding
14 disallowance for 2024 Power Generation projects and a 20% capital project funding
15 disallowance for 2025 Power Generation projects⁹.

16

17 **Q25. Why does Witness Kindschy recommend disallowances for routine**
18 **maintenance projects, including the use of different funding disallowance rates**
19 **for 2024 work versus 2025 work on the same project?**

20 A25. Witness Kindschy indicates the later year (2025) work is mostly at an earlier stage
21 of development, is further in the future, and should therefore carry a higher
22 disallowance factor when compared to nearer term (2024) work¹⁰.

⁹ Witness Kindschy DT, pages 8-9. Witness Kindschy reduces the Company’s routine maintenance capital projects greater than \$1 million that are in a PAT-0 or PAT-1 state.

¹⁰ Witness Kindschy DT, page 9, lines 1-3.

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1 **Q26. How does AACE address the typical variation in actual costs as compared to**
2 **what Witness Kindschy has done?**

3 A26. The AACE guidelines clearly state, as can be found on Staff Exhibit S-16.3, page
4 3 of 10, Note A: “The state of process technology and availability of applicable
5 reference cost data affect the range markedly. The +/- value represents typical
6 variation of actual costs from the cost estimate *after application of contingency ...*
7 *for the given scope* (emphasis added).” Witness Kindschy has applied her
8 disallowance factors to funding requests made by the Company that have already
9 been “de-risked” because all contingency funding has been excluded from the
10 amounts being requested in the instant case.

11

12 **Q27. Do you have any concerns regarding the application of the AACE cost estimate**
13 **classification system by Witness Kindschy?**

14 A27. Witness Kindschy’s application of the AACE cost estimate classification is flawed
15 because it applies her 15% and 20% reduction factors without recognizing or
16 acknowledging that the Company’s projects do not include requests for project
17 contingency funding. She utilizes the 15% and 20% factors, indicates she has
18 followed the AACE guidelines, then incorrectly applies the adjustments to the
19 Company’s projected capital expenditures without adding in project contingency
20 as directed in the AACE guidelines.

21

22 **Q28. What is the impact of applying reduction factors to projections without adding**
23 **contingency?**

24 A28. Applying reduction factors to projections that exclude contingency inflates Witness
25 Kindschy’s disallowance recommendations. Below is a simplified example on a

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1 single project that illustrates the calculation error behind Witness Kindschy's
2 recommendations.

3

4 **Table 1 AACE Method versus Witness Kindschy's Method**

Method	Project Cost	Reduction Factor	Reduction	Remaining
AACE Method	\$4 + \$1 of contingency	20%	\$5 x -20% = -\$1	\$5 - \$1 = \$4
Kindschy Method	\$4 + \$0 of contingency	20%	\$4 x -20% = -\$0.8	\$4 - \$0.8 = \$3.2

5

6 As shown in Table 1 above, proper application of the AACE method and applying
7 a 20% reduction factor results in an amount remaining (\$4) near the base project
8 spend excluding contingency (\$4). However, applying Witness Kindschy's method
9 of excluding contingency in the project cost, which is not consistent with AACE
10 cost estimate standards, results in an amount remaining (\$3.2) well less than the
11 base project spend excluding contingency (\$4). In other words, Witness
12 Kindschy's method inappropriately reduces projected capital expenditures more
13 than the AACE method would have one do.

14

15 **Q29. Why has this error not been previously recognized?**

16 A29. To the best of my knowledge, the MPSC Staff has not previously utilized the AACE
17 methodology to make any specific Energy Supply project funding adjustments in a
18 Company rate case.

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1 **Q30. How do you respond to Witness Kindschy's claim that a short-term variance**
2 **between a forecast and actual expenditure supports the use of specific**
3 **accuracy range adjustment factors to project estimates as the basis to**
4 **recommend project disallowances¹¹?**

5 A30. A variation between actual and forecasted spend over a 6-month period is not
6 indicative of total performance over the entire project duration. As discussed
7 above, capital projects are managed on a total beginning-to-end basis with monthly
8 estimates only developed to track general project evolution and annual total budget
9 targets. A project being underspent (actual expenditures were less than a forecast)
10 in the past does not justify reductions to future projections. On the contrary, if
11 project spending is lower than expected due to a timing variance, the future
12 spending will likely be higher than the original monthly forecast as a result of
13 spending milestones shifting to the future.

14

15 **Q31. What should the Commission find with respect to Witness Kindschy's**
16 **application of AACE cost estimate standards to the Company's routine capital**
17 **expenditures?**

18 A31. The Commission should find Witness Kindschy misapplied her 15% and 20%
19 reductions by using the Company's projections that already exclude contingency as
20 is the Company's practice, which is inconsistent with the AACE instructions
21 provided in her own exhibit. Also, since Witness Kindschy relied, at least in part,
22 on timing variances to justify further reductions in projected routine capital projects
23 that are at a PAT0 or PAT1 as described above in my testimony, Witness
24 Kindschy's proposed reductions for the 7-month period ending December 31, 2024

¹¹ Witness Kindschy DT, page 9, lines 4-7.

Line
No.

1 and 12-month period ending December 31, 2025 of \$39.1 million¹² should be
2 dismissed.

3

4 **Part V – The Company’s black start projects are justified, and the Company took**
5 **balanced, reasonable, and necessary steps to be transparent while protecting**
6 **security sensitive information in this instant case**

7

8 **Q32. What does ABATE Witness York recommend with respect to the Company’s**
9 **projected test year capital expenditures for the black start projects?**

10 A32. Witness York recommends removal of \$34.4 million of 2023-2025 projected
11 capital expenditures for five black start projects¹³. The \$34.4 million is comprised
12 of \$12.6 million of 2023-2024 expenditures on Project 10570 & 20255 (Exhibit A-
13 12, Schedule B5.1 page 2, line 37), \$8.1 million of 2023-2024 expenditures on
14 Project 17611 (Exhibit A-12, Schedule B5.1 page 2, line 38), \$4.4 million of 2023-
15 2024 expenditures on Project 18320 (Exhibit A-12, Schedule B5.1 page 2, line 39),
16 \$2.8 million of 2025 expenditures on Project 19737 (Exhibit A-12, Schedule B5.1
17 page 7, line 225 - Blackstart Peaker Unit 2 Starting System), and \$6.4 million of
18 2025 expenditures on Project 18090 (Exhibit A-12, Schedule B5.1 page 7, line 231
19 - Blackstart Unit Major Overhaul).

20

21 **Q33. What is the basis of Witness York’s proposed removal of black start project**
22 **capital expenditures?**

23 A33. Witness York states that because the supporting Project Management Process
24 (PMP) documents for the projects are redacted, the parties cannot independently

¹² Witness Kindschy DT, page 9, lines 7-11.

¹³ Witness York DT, page 19, Table JAY-3 (lines 3-7).

Line
No.

1 review and assess the scope of this project, the project timeliness, or any revisions
2 that have occurred¹⁴.

3

4 **Q34. Did the Commission address the issue of redacted black start project details**
5 **in the last DTE Electric rate case, Case No. U-21297?**

6 A34. Yes. In the Case No. U-21297 Order dated December 1, 2023, the Commission
7 found inclusion of the majority of expenditures associated with the black start
8 projects in rate base to be appropriate¹⁵. After considering the project evidence the
9 Company provided and the International Transmission Company's (ITC¹⁶) support
10 for both the absolute necessity of black start units and the need to keep the project
11 information on a highly confidential basis, the Commission agreed with the
12 Company's position and did not adopt the disallowances recommended by ABATE
13 and the AG which were based on the Company not disclosing detailed project
14 information.

15

16 **Q35. What should the Commission find with respect to Witness York's proposed**
17 **disallowance of black start project capital expenditures?**

18 A35. The Commission should find the Company properly protected the security sensitive
19 information in the instant case, just as it did in Case No. U-21297. Witness York's
20 direct testimony essentially reiterates arguments that were already considered and
21 rejected in the Company's previous rate case and her \$34.4 million disallowance
22 recommendation should be rejected.

¹⁴ Witness York DT, pages 22-25.

¹⁵ Case No. U-21297 Order dated December 1, 2023, pages 40-44.

¹⁶ ITC is the owner of the grid blackout restoration plan and tightly controls information on black start assets (see ITC Witness Chindhade's DT, pages 3-5).

Line
No.

1 **Q36. What does Staff Witness DeCooman recommend with respect to the**
2 **Company's bridge period capital expenditures for the black start projects?**

3 A36. Witness DeCooman recommends partial disallowance of \$1.4 million and \$1.2
4 million in capital expenditures in 2023 and 2024¹⁷, respectively. This
5 recommended disallowance is comprised of \$0.3 million of capital expenditures for
6 Project #10570 & 20255 in 2023, \$0.3 million of capital expenditures for Project
7 #10570 & 20255 in 2024, \$0.1 million of capital expenditures for Project #17611
8 in 2023, \$0.9 million of capital expenditures for Project #17611 in 2024, \$1.0
9 million of capital expenditures for Project #18320 in 2023, and \$0.1 million of
10 capital expenditures for Project #18320 in 2024¹⁸.

11

12 **Q37. What is the basis of Witness DeCooman's proposed partial disallowance of**
13 **bridge period black start project capital expenditures?**

14 A37. For 2023, Witness DeCooman bases his proposed adjustments on variances
15 between actual project capital expenditures and the amounts projected in Exhibit
16 A-12, Schedule B5.1, page 2. This adjustment related to 2023 capital expenditures
17 is addressed in Part III of my rebuttal testimony.

18

19 For 2024, Witness DeCooman calculates the 2-year percentage difference between
20 the amounts forecasted in the Company's last case, Case No. U-21297, and the
21 actual capital expenditures incurred for each black start project. Based on an
22 average 14% difference between the amounts forecasted and the actual capital
23 expenditures, he reduces the Company's 2024 projections by 14%¹⁹.

¹⁷ Witness DeCooman DT, page 10, lines 5-7.

¹⁸ Witness DeCooman DT, page 9, lines 7-8.

¹⁹ Witness DeCooman DT, page 8, line 1 through page 9, line 4.

Line
No.

1 **Q38. How do you respond to Witness DeCooman's recommendation to reduce the**
2 **black start project capital expenditures in 2024 based on the percentage**
3 **variance between what was requested in the last rate case and the actual**
4 **capital expenditures?**

5 A38. I disagree. I do not find it reasonable to assume that because a group of projects in
6 total were underspent (actuals were less than a forecast) in the past, future
7 projections for those projects should be reduced. On the contrary, if certain project
8 spending is lower than expected in a given year, the future year spending may be
9 higher than the original forecast as a result of spending milestones shifting to future
10 years. Additionally, Witness DeCooman does not consistently apply this spend
11 forecast adjustment logic to projects which saw higher capital expenditures than
12 forecasted which would otherwise adjust such projects' spending forecasts higher.

13

14 **Q39. What should the Commission find with respect to Witness DeCooman's**
15 **proposed partial disallowance of black start project capital expenditures?**

16 A39. The Commission should find the fact that a project or group of projects underspent
17 during a period compared to a forecast does not demonstrate future project
18 expenditures should be reduced and therefore Witness DeCooman's \$1.2 million
19 2024 disallowance recommendation should be rejected.

20

21 **Part VI – Staff's recommended reductions on Trenton Channel BESS non-contract**
22 **spend projections are not well-supported**

23

24 **Q40. What does Staff Witness DeCooman recommend with respect to the Trenton**
25 **Channel BESS non-contract spend?**

Line
No.

1 A40. Witness DeCooman recommends removing \$9.9 million of 2024 and 2025 capital
2 expenditures from the Company's projections based on uncertainty in the estimates
3 for work that does not have established contracts²⁰.
4

5 **Q41. How did Witness DeCooman calculate a \$9.9 million reduction?**

6 A41. Witness DeCooman's calculation can be found in his Exhibit S-10.6. In that
7 exhibit, he subtotals certain lines of expenditures in 2024 and 2025. His
8 recommended removal includes 10% of the 2024 subtotaled amount and 20% of
9 the 2025 subtotaled amount.
10

11 **Q42. What is the basis of the specific 10% and 20% multipliers utilized in Witness**
12 **DeCooman's removal adjustment?**

13 A42. Witness DeCooman does not explain how he arrived at the specific 10% and 20%
14 reductions for 2024 and 2025, respectively.
15

16 **Q43. Do you have any observations concerning Witness DeCooman's calculations?**

17 A43. It appears Witness DeCooman was attempting to calculate expenditures that are not
18 associated with an existing contract. However, in Witness DeCooman's calculation
19 of non-contracted work in Exhibit S-10.6 (the row below row 11), he inconsistently
20 includes line 8 (owner's engineer and expert support) in his calculation, even
21 though that line item is listed as being subject to a contract. Witness DeCooman
22 also includes all the funding shown in lines 9 and 10 (project overheads and
23 AFUDC), even though the majority of the expenditures on these lines are dictated
24 by direct spend for which contracts exist. In short, Witness DeCooman's

²⁰ Witness DeCooman DT, page 17, line 11 through page 18, line 4.

Line
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1 calculation of non-contract spend, which he relies on to develop his capital
2 reduction recommendation, inconsistently includes spend associated with
3 contracts.

4

5 **Q44. What should the Commission find with respect to Witness DeCooman's partial**
6 **removal of Trenton Channel BESS non-contract spend projections?**

7 A44. The Commission should find Witness DeCooman's adjustment factors lack specific
8 explanation and justification. Additionally, inconsistencies are included in the
9 calculation. Accordingly, his recommendation to remove \$9.9 million from the
10 Trenton Channel BESS projection should be dismissed.

11

12 **Part VII – ABATE's proposed disallowance related to River Rouge**

13 **Decommissioning based on minor paperwork differences is unwarranted**

14

15 **Q45. What is the basis of ABATE Witness York recommending a partial reduction**
16 **for 2024 expenditures on the River Rouge Decommissioning project (Exhibit**
17 **A-12, Schedule B5.1, page 2, line 25)?**

18 A45. In reviewing the Company's project documentation, Witness York identified an
19 annual difference for 2024 between the capital expenditures included in my exhibits
20 and the Company's CARF retiming form.²¹ Exhibit A-12, Schedule B5.1, page 2,
21 line 25 projects \$12.8 million of expenditures in 2024. The CARF retiming form,
22 included as Witness York's Exhibit AB-2, page 3, shows \$8.4 million in 2024.
23 Based on this difference, Witness York recommends disallowing the \$4.4 million

²¹ Witness York DT, page 21 line 9 through page 22 line 7 and York DT page 19, Table JAY-3.

Line
No.

1 difference between the annual amount in the exhibit and the annual amount in the
2 CARF retiming form.

3

4 **Q46. How do you respond to Witness York's recommended disallowance for the**
5 **River Rouge Decommissioning project?**

6 A46. A closer look at the CARF retiming form (Witness York's Exhibit AB-2, page 3)
7 shows a total authorized funding amount of \$94.9 million for the River Rouge
8 Decommissioning project. This includes \$48.3 million of projected expenditures
9 in 2025 associated with continuing the demolition of the now-retired power plant.
10 As discussed further on page 38 of my revised direct testimony, the Company will
11 address and request the remaining decommissioning expenditures in a future rate
12 case. There is more than enough funding authorized and anticipated for this long-
13 term project to cover the \$4.4 million difference Witness York identifies.

14

15 **Q47. What should the Commission find with respect to Witness York's**
16 **recommendation related to a partial removal of River Rouge**
17 **Decommissioning expenditures?**

18 A47. The Commission should find the Company's approval documents have sufficient
19 approved funding to cover the 2024 difference in paperwork that Witness York
20 points out for this long-term project. Accordingly, Witness York's \$4.4 million
21 disallowance recommendation should be rejected.

Line
No.

1 **Part XIII – The Company appropriately calculated overheads on the Slocum**

2 **Battery Pilot**

3

4 **Q48. What is the basis of Staff Witness DeCooman's recommendation to reduce the**
5 **projected capital expenditures for the Slocum Battery Pilot project (Exhibit**
6 **A-12, Schedule B5.1, page 2, line 40) by \$2.2 million²²?**

7 A48. Witness DeCooman recommends reducing the projected capital expenditures for
8 the Slocum Pilot by the amounts the overheads increased from the Company's
9 previous rate case, Case No. U-21297, because he claims the Company did not
10 adequately support the nature of this cost increase²³.

11

12 **Q49. How did the Company explain the cost increase in overheads from the last case**
13 **to the instant case?**

14 A49. As shown in Witness DeCooman's Exhibit S-10.3, page 5, the Company explained
15 the increase in overheads was driven by increases in material and labor costs on
16 which the indirect overheads are calculated and applied.

17

18 **Q50. How are overheads allocated to capital projects?**

19 A50. The allocation of overheads to the Slocum Battery pilot, as with all other Company
20 capital projects, is done on a monthly basis. Overhead costs are charged to all
21 capital projects based on actual direct costs. Direct costs include costs like labor,
22 material, and contract labor that are charged directly to the projects.

23

24 **Q51. How did the overhead charges change from the last case to the instant case?**

²² Witness DeCooman DT, page 12, lines 16-17.

²³ Witness DeCooman DT, page 13, lines 5-6.

Line
No.

1 A51. In Case No. U-21297, the Slocum Battery pilot projected cost was \$34.7 million.
2 This was comprised of \$30.9 million of direct costs and \$4.8 million of indirect
3 (overhead) costs as shown in Witness DeCooman's direct testimony, page 12.
4 Overhead costs represented 14% (\$4.8 million / \$34.7 million) of the total project
5 in Case No. U-21297.

6

7 In the instant case, the Slocum Battery pilot is projected to be \$44.7 million as
8 shown in Witness DeCooman's direct testimony, page 12. This is comprised of
9 \$37.8 million of direct costs and \$6.9 million of indirect (overhead) costs.
10 Overhead costs represent 15% (\$6.9 million / \$44.7 million) of the total project in
11 the instant case.

12

13 As shown above, the overhead costs, as a percentage of the total project, have
14 remained consistent between the previous case and the instant case. The increase
15 in indirect overhead costs between the two cases is a result of increased direct
16 project costs.

17

18 **Q52. What should the Commission find with respect to Witness DeCooman's**
19 **recommendation to exclude the difference in Slocum Battery Pilot overheads**
20 **from the last case to the instant case?**

21 A52. The Commission should find the Company appropriately estimated the indirect
22 project overheads in the instant case for the Slocum Battery Pilot. Witness
23 DeCooman's \$2.2 million reduction recommendation should be rejected.

24

Line
No.

1 **Part IX – The Trenton Channel Seawall project is worthy of recovery in the instant**
2 **case**

3
4 **Q53. What is the basis of ABATE Witness York recommending full disallowance of**
5 **the Trenton Channel Seawall project (Exhibit A-12, Schedule B5.1, page 2, line**
6 **28)?**

7 A53. Witness York recommends excluding the entire Trenton Channel Seawall project
8 (\$10.9 million²⁴) from rates at this time because the Company provided an
9 Appropriation Request document that does not support the level of expenditures
10 shown in the Company's Exhibit A-12, Schedule B5.1.²⁵

11

12 **Q54. What is prompting the Company to complete the Trenton Channel Seawall**
13 **project?**

14 A54. The project is required to restore the seawall's integrity at the Trenton Channel
15 Power Plant site. The existing infrastructure is at its end of life and must be
16 replaced to ensure the stability of the land surrounding the riverfront. Additionally,
17 the City of Trenton stipulated the Company develop a pedestrian greenway path
18 that provides access to the Detroit River riverfront as part of the approved
19 demolition permit for the Trenton Channel Power Plant. Trenton Channel Power
20 Plant was recently demolished in anticipation of construction of the new Trenton
21 Channel BESS.

²⁴ Witness York DT, page 20, line 16 through page 21, line 1.

²⁵ Witness York DT, page 19, Table JAY-3 line 1 and York DT, page 21, lines 3-8.

Line
No.

1 **Q55. How is the Trenton Channel Seawall Project progressing?**

2 A55. Thus far, the Company has spent over \$500 thousand to support engineering and
3 design work. The full project is scheduled to be completed in 2025 and is
4 progressing as planned.
5

6 **Q56. How do you respond to Witness York's statement that the Company's**
7 **appropriation request does not support the level of expenditures in Exhibit A-**
8 **12, Schedule B5.1²⁶?**

9 A56. Witness York's Exhibit AB-2 page 1 shows a signed appropriations request for \$1.1
10 million for the Trenton Channel Seawall project. This funding supports the design
11 and engineering work for the project. An appropriations request that includes the
12 full project budget will be executed once the design and engineering is complete.
13

14 **Q57. What should the Commission find with respect to Witness York's proposed**
15 **exclusion of the Trenton Channel Seawall project?**

16 A57. The Commission should find there is no reason to expect the Trenton Channel
17 Seawall project will not be completed. The project is required to restore sections
18 of the seawall that are in a failing state to ensure the protection of the waters of the
19 state and to maintain a safe condition. The project is in the best interest of the
20 community and continues to make progress as demonstrated by actual expenditures
21 and scope completed. Witness York's \$10.9 million disallowance recommendation
22 should be rejected.

²⁶ Witness York DT, page 21, lines 5-7.

Line
No.

1 **Part X – GLREA’s request for an electrical distribution system-connected BESS**
2 **analysis is unnecessary**
3

4 **Q58. What does Witness Richter recommend with respect to the Company’s plans**
5 **for future BESS capacity?**

6 A58. Witness Richter recommends that the Commission, “direct the Company to
7 carefully consider the benefits of installing future BESS capacity in smaller,
8 distribution-connected units, and that any future BESS proposal should include an
9 analysis of opportunities for distribution-connected BESS, and why that option
10 was, or was not, selected by the Company.”²⁷
11

12 **Q59. Did the DTE Electric Integrated Resource Plan (IRP) Case No. U-21193**
13 **indicate anything that is relevant to the procurement of new energy resources**
14 **by the Company?**

15 A59. The Order dated July 26, 2023, from the Company’s latest IRP case, Case No. U-
16 21193, states on page 5, “In acquiring the renewable and storage resources...the
17 Company will comply with the MPSC’s Competitive Procurement Guidelines for
18 Rate-Regulated Electric Utilities...” These Competitive Procurement Guidelines
19 were approved by the Commission via the September 9, 2021, Order in Case No.
20 U-20852.
21

22 **Q60. How do the Competitive Procurement Guidelines apply to the consideration**
23 **and evaluation of distribution-connected units?**

²⁷ Witness Richter DT, page 62 line 22 through page 63 line 2.

Line
No.

1 A60. The Competitive Procurement guidelines state, “Utilities should conduct an open,
2 non-discriminatory Competitive Procurement process that fairly considers both
3 third-party and utility ownership structures, resource types or combinations of
4 resource types, sizes/capacities, ancillary services, and cost reducing grid benefits
5 with transparency on how they will be evaluated.”²⁸ Additionally, the Competitive
6 Procurement Guidelines provide considerations for utilities in evaluating bids,
7 including but not limited to “...reductions in transmission congestion and loss
8 costs, reduced distribution system losses, deferred or avoided transmission or
9 distribution investments, and other locational benefits as applicable.”²⁹

10

11 **Q61. What do you conclude about Witness Richter’s recommendations?**

12 A61. The Competitive Procurement guidelines already require the open and transparent
13 consideration and evaluation of distribution-connected resources, including
14 different ownership structures and the benefits that different projects can provide,
15 including distribution-level benefits. Thus, no further action is necessary by the
16 Commission and Witness Richter’s recommendation should be disregarded.

17

18 **Q62. Does this conclude your rebuttal testimony?**

19 A62. Yes, it does.

²⁸ Case No U-20852 Order dated September 9, 2021, Exhibit A, Competitive Procurement Guideline 3.a.

²⁹ Case No U-20852 Order dated September 9, 2021, Exhibit A, Competitive Procurement Guideline 4.f.

1 JUDGE WALLACE: Next.

2 MR. CHRISTINIDIS: The Company's next
3 witness, your Honor, is David C. Milo. Mr. Milo
4 sponsored the Qualifications and Direct Testimony of
5 David C. Milo, consisting of a cover sheet and 18 pages
6 of questions and answers. He also sponsored Exhibit A-12
7 Schedule B5.2, and Exhibit A-13 Schedule C5.2. He did
8 not sponsor any rebuttal testimony. So with that, your
9 Honor, the Company would move to bind into the record the
10 Qualifications and Direct Testimony of David C. Milo, and
11 move the admission of Exhibit A-12 Schedule B5.2, and
12 Exhibit A-13 Schedule C5.2.

13 JUDGE WALLACE: Is there any objection to
14 binding in the direct testimony of Mr. Milo?

15 Hearing none, the testimony is bound in.

16 Is there any objection to admitting the
17 Exhibits A-12, A-13 and associated schedules sponsored by
18 Mr. Milo?

19 O.K. We'll admit those, again, at the
20 close.

21 (Testimony Bound In.)

22 - - -
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
DAVID C. MILO

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF DAVID C. MILO

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

2 A1. My name is David C. Milo (he/him/his). My business address is One Energy Plaza,
3 Detroit, Michigan 48226. I am employed by DTE Electric as a Fuel Resources
4 Specialist in the Operations and Logistics group within the Fuel Supply department.

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

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

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

10 A3. I have a Bachelor of Arts Degree in Accounting and a Master of Business
11 Administration Degree, in Finance, both from Michigan State University, East
12 Lansing, Michigan.

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

15 A4. In 2004, I joined DTE Energy in the Property Tax department as a Senior Tax
16 Advisor. In this capacity, I was responsible for property tax compliance for
17 Michigan Consolidated Gas Company and various other subsidiaries of DTE
18 Energy.

20 In 2008, I transferred to the Budget, Forecast and Reporting group as a Principal
21 Analyst. In this capacity, my responsibility was to assist in the preparation of
22 corporate budgets and forecasts and to prepare reports for management on various
23 financial performance measures for DTE Energy.

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1 In 2010, I transferred to the Asset Management group where I prepared reports on
2 capital asset expenditures for DTE Energy. In November of that same year, I
3 transferred to the Gross Margin group as the fuel accountant. In this capacity, my
4 responsibilities were to prepare the accounting for the purchase and expense of all
5 fuels used in the production of electricity for DTE Electric and preparation of
6 internal and regulatory reports thereon.

7

8 In 2013, I transferred to the Fuel Supply department of DTE Electric as a Fuel
9 Resources Specialist in the Planning and Procurement group. My responsibilities
10 included preparation of the budget and forecasts regarding all fossil fuels (i.e., coal,
11 natural gas & oil) used by DTE Electric for electric generation, preparing
12 management reports on DTE Electric's fossil fuels, and assisting in various
13 accounting activities.

14

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

16 A5. In 2016, I moved to the Operations and Logistics group of Fuel Supply where I
17 currently manage the Company's railcar fleet. I am responsible for the procurement
18 and maintenance of the Company's railcar fleet. My duties include ensuring an
19 adequate number of railcars are under the Company's control to meet coal delivery
20 needs and they are maintained to meet operational, safety and contractual standards.
21 In that role, I work with Midwest Energy Resources Company (MERC) personnel
22 and their operations to coordinate coal deliveries and movements of railcars.

Line
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- 1 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
2 **Commission (MPSC or Commission)?**
- 3 A6. Yes. I have sponsored testimony in the following cases:
- 4 U-17097-R 2013 Power Supply Cost Recovery (PSCR) Reconciliation
5 U-17319 2014 PSCR Plan
6 U-17319-R 2014 PSCR Reconciliation
7 U-17680 2015 PSCR Plan
8 U-18014 2016 DTE Electric Rate Case
9 U-18255 2017 DTE Electric Rate Case
10 U-20162 2018 DTE Electric Rate Case
11 U-20561 2019 DTE Electric Rate Case
12 U-20836 2022 DTE Electric Rate Case
13 U-21297 2023 DTE Electric Rate Case

Line
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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to discuss and support the reasonableness and
4 prudence of DTE Electric Fuel Supply's (Fuel Supply) and MERC's Fuel Handling
5 actual \$8.3 million of O&M expenses for the 12-month historic period ended
6 December 31, 2022, and the projected \$8.1 million O&M expenses for the 12-
7 month projected test period ending December 31, 2025. I also discuss and support
8 \$2.2 million of capital expenditures for the historical test year ended December 31,
9 2022, the projected capital expenditures of \$2.9 million from January 1, 2023,
10 through the projected bridge period ending December 31, 2024, and the projected
11 capital expenditures of \$1.2 million for the 12-month projected test period ending
12 December 31, 2025. I also address how the Company's transition from coal
13 generated electricity, as explained in the Company Integrated Resource Plan Case
14 No. U-21193, will affect MERC transshipment operations and the railcar fleet for
15 the Company. Furthermore, I specifically address the planned retirement of
16 operations at MERC as directed in the December 1, 2023, Commission Order in
17 Case No. U-21297 (December 1 Order).

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

2 A8. Yes. I am sponsoring the following exhibits:

	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
3			
4	A-12	B5.2	Projected Capital Expenditures – Midwest Energy
5			Resources Company (MERC) & Fuel Supply
6	A-13	C5.2	Projected Operation and Maintenance Expenses –
7			Fuel Supply & Midwest Energy Resources Company
8			(MERC)

9

10 **Q9. Were these exhibits prepared by you or under your direction?**

11 A9. Yes, they were.

12

13 **Q10. How is your testimony organized?**

14 A10. My testimony consists of the following three (3) parts:

15	Part I	Overview of MERC and Fuel Supply
16	Part II	MERC and Fuel Supply Capital Investments
17	Part III	Fuel Supply and MERC Operations & Maintenance Expenses

18

19 **Part I – Overview of MERC and Fuel Supply**

20

21 **Q11. What is MERC?**

22 A11. MERC, a wholly owned subsidiary of DTE Electric, is a coal terminal which
 23 provides coal transportation and transshipment services to DTE Electric and other
 24 third-party utility and industrial customers through its Superior, Wisconsin
 25 terminal. MERC accepts coal deliveries by rail from the western United States and

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1 loads those coal deliveries onto Great Lakes freighters for delivery to power plants
2 and other industrial facilities around the Great Lakes basin.

3

4 **Q12. Why is MERC included in this rate case filing?**

5 A12. As a wholly owned subsidiary of DTE Electric, MERC is fully consolidated into
6 DTE Electric. The accounting and ratemaking treatment of MERC's revenues and
7 costs are specified by MPSC Orders in Case No. U-5041¹, dated September 17,
8 1976, and Case No. U-5108², dated May 27, 1977.

9

10 **Q13. What is MERC's role in coal transportation to the Company's two remaining**
11 **operating coal-generation power plants?**

12 A13. MERC is critical to the Belle River Power Plant (BRPP) as it is the only source of
13 low-sulfur western (LSW) coal for the plant. MERC is also an important coal
14 delivery option, supplying a significant portion of LSW coal to the Company's
15 Monroe Power Plant (MPP). BRPP does not have a rail unloading system or direct-
16 rail delivery capacity capable of supplying its coal consumption requirements and
17 can only be supplied by lake vessel deliveries. There are no other facilities and/ or
18 options for delivering the large coal quantities to BRPP, since other U.S. coal
19 terminals cannot consistently accommodate the required lake vessel sizes. The
20 continued utilization of MERC is the most economic method of delivering LSW
21 coal to the BRPP, including and through the period of the plant's planned cessation
22 of coal-fired operation as proposed in Case No. U-21193. Regarding MPP, MERC
23 supplies a large amount of LSW coal to the plant. These deliveries through MERC

¹ <https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16522>, Order MPSC Case No. U-5041, accessed February 16, 2024.

² <https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16595>, Order MPSC Case No. U-5108, accessed February 16, 2024.

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1 are utilized to maintain reliable coal supply to MPP and are the most economical
2 means to supplement rail deliveries to MPP.

3

4 **Q14. What is the planned future of MERC?**

5 A14. The planned future of MERC, in light of the Order in Case No. U-21193 approving
6 a fuel conversion from coal to natural gas at BRPP, is to cease MERC transshipment
7 operations at the end of June 2026. This timing coincides with the projected end
8 of coal deliveries to BRPP. Given this planned retirement date for MERC, any
9 spending will be designed to maintain safe and environmentally compliant
10 operation but otherwise minimize investment. Financial resources and expenditures
11 will be reviewed for reasonableness and prudence and limited to those that are
12 determined to be necessary for coal deliveries to the two DTE Electric plants still
13 burning coal through MERC's retirement date.

14

15 **Q15. Can you describe the railcar fleet and its role in supplying fuel to the power**
16 **plants that rely on coal for the generation of electricity.**

17 A15. The Company, through its Fuel Supply department, currently controls a fleet of
18 railcars to transport coal from the mines in Wyoming, Montana, and Pennsylvania
19 to the Company's power plants. This fleet is critical to delivering the required large
20 amounts of coal at the lowest reasonable cost. Each car has the capacity to hold
21 approximately 120 tons of coal. The coal is moved from the mines to the
22 Company's power plants in a group of 130 connected railcars (using couplers),
23 commonly referred to as a unit train, and a railcar can travel over a hundred
24 thousand miles in a single year. This method is standard across the utility industry
25 and has been used for decades.

Line
No.

1 **Q16. How does railcar fleet maintenance affect Company operations?**

2 A16. It is important for ensuring railcar regulatory compliance and meeting the
3 Company's coal delivery requirements to regularly maintain railcars. The railroad
4 industry is highly regulated with governing agencies including the Surface
5 Transportation Board (STB), Federal Railroad Administration (FRA) and
6 American Association of Railroads (AAR) to ensure a safe system. Accordingly,
7 the railroads have implemented a rigorous inspection protocol for the railcars
8 operating on their railroad system. The inspections can unilaterally remove
9 defective railcars from service due to the attendant operating risks, which would
10 require the Company to procure an equivalent amount of railcars to meet its
11 delivery requirements, likely at greater expense. The Company's capital program
12 is designed to limit and/or avoid repairs to structural aspects of the railcar and other
13 components, including the wheels and bearings, and the costs incurred for such
14 repairs.

15

16 **Q17. What is the planned future of the railcar fleet?**

17 A17. The Company plans to move up the retirement date of the railcar fleet to 2032,
18 consistent with the planned retirement of the two remaining coal fired units at MPP
19 as explained in the Case No. U-21193 IRP case.

Line
No.

1 **Part II – MERC and Fuel Supply Capital Investments**

2

3 **Q18. Can you explain the nature of MERC's capital expenditures and how declining**
4 **coal delivery volumes affect the economics?**

5 A18. The MERC capital expenditures are for the operation of the coal terminal that
6 processes rail shipments of LSW coal for lake vessel delivery to DTE Electric's
7 power generation plants in southern Michigan. MERC is a large industrial facility
8 and has unavoidable fixed costs such as rail tracks and conveyor belts to move coal,
9 and with high volumes can take advantage of economies of scale. The decline in
10 the amount of coal being transshipped necessarily results in a higher dollar per ton
11 cost metric compared to higher volume periods, as unavoidable fixed costs can't be
12 lowered without risk to safe and reliable operations. The Company expects MERC
13 to transship similar volumes in 2023 and 2024 compared to the amount in 2022,
14 with a slight decrease in volume during the projected test period ending December
15 31, 2025. This decrease will result in lower total cost as discussed below.

16

17 **Q19. How does the amount of MERC capital expenditures change from the**
18 **historical year ended December 31, 2022 through the projected test period**
19 **ending December 31, 2025?**

20 A19. The amount of capital expenditures decreases almost 90% for MERC, from \$1.2
21 million in 2022 to only \$154 thousand in 2025. It should be noted that capital
22 spending is significantly reduced each of the projected years of this general rate
23 case. The reduction is about \$300 thousand in 2023 for total spend of \$926
24 thousand. The reduction for year ending December 2024 is roughly \$600 thousand
25 for a total spend of \$290 thousand. The diminished amounts are a result of

Line
No.

1 continued evaluation of spending, limiting expenditures to only critical items that
2 could stop operations if not addressed, and considering the transition from coal
3 generation addressed in the Case No. U-21193 IRP Order.
4

5 **Q20. What does the capital program for the railcar fleet entail, what is the spending**
6 **plan, and why is it important for the Company's customers?**

7 A20. The capital program for the Company's railcar fleet addresses two key components
8 of the railcars; the truck and the draft systems. The truck system is a chassis or
9 framework-like structure underneath a railroad car to which wheel axles (and,
10 hence, wheels) are attached through bearings. The draft system is an assembly
11 behind the couplers at each end of the car to manage the compression and tension
12 forces between the cars of the unit train. These railcar components are subject to
13 significant physical forces, weighing about 21 tons unloaded and 141 tons loaded
14 with coal, incur wear and tear over time and need to be replaced. The railcar
15 industry recommendation is that the truck and draft assembly be rebuilt after 1
16 million miles of operations. The Company's capital program focuses on those cars
17 with over 1 million miles of operation and allocates one million dollars per year to
18 replacing components on these railcars. The program was implemented almost a
19 decade ago and is expected to be completed in 2025. This program is important to
20 our customers, since it is designed to limit and/or avoid repairs to structural aspects
21 of the railcar and other components, including the wheels and bearings, and the
22 costs incurred for such repairs. The program work accomplished proactively by the
23 Company at private shops also lowers expenditures by avoiding costlier repairs
24 performed at the railroad shops after inspection and directives from railroad
25 personnel.

Line
No.

1 **Q21. How does the transition from coal-fired generation at BRPP and MPP affect**
2 **the railcar capital investment program?**

3 A21. As mentioned earlier, the capital investment program the Company implemented is
4 scheduled to be completed at the end of 2025. The Company will use the railcars
5 through the life of MPP, therefore it is reasonable and prudent to complete the
6 capital program. It should be noted the program is focused only on the railcars that
7 will still be required through the life of MPP. The Company expects to have no
8 capital expenditures from 2026 - 2032 for the railcar fleet. The Company is
9 confident of this end date because a “teardown” of a sample of railcars was
10 performed at the end of 2023 to inspect components. Based on this independent
11 assessment of the condition of the railcars, DTE Electric’s capital program was
12 determined to be effective and no more capital program spending should be
13 required after 2025 to keep the fleet in safe operating order. The inspector’s
14 assessment indicated that the Company’s railcar fleet was well maintained and, in
15 his opinion, should have minimal issues continuing in service through 2032.

16

17 **Q22. What does Exhibit A-12, Schedule B5.2 show?**

18 A22. Exhibit A-12, Schedule B5.2 shows capital expenditures for MERC and Fuel
19 Supply for the historical test period 2022, as well as forecasted capital expenditures
20 for the 24-month projected bridge period (January 1, 2023 through December 31,
21 2024) and the 12-month projected test year ending December 31, 2025.

22

23 **Q23. What is the rationale for MERC and Fuel Supply capital expenditures shown**
24 **on Exhibit A-12, Schedule B5.2?**

25 A23. All the expenditures described in Q24 – Q26, for the period of January 2022 through
26 December 2025 are related to maintaining safety, meeting environmental

Line
No.

1 requirements, operating reliably, and/or replacing end-of-life equipment. These
2 expenditures are not avoidable and are reasonable and prudent and necessary for
3 MERC's coal transshipment capabilities to BRPP and Fuel Supply railcar
4 availability.

5

6 **Q24. What are the capital expenditures for MERC and Fuel Supply for the**
7 **historical test year 2022 included on Exhibit A-12, Schedule B5.2, column (b),**
8 **lines 9 and 12, respectively?**

9 A24. The total capital expenditures for both entities in 2022 were \$2.2 million, as detailed
10 on lines 2 through 8, and 11 of the Exhibit. The total MERC expenditures on line 9
11 of \$1.2 million consists of \$0.56 million for conveyor belting to replace damaged
12 belting needed to keep coal moving through the facility from train unloading to
13 vessel loading, \$0.3 million for the D11 Caterpillar dozer needed to move and form
14 coal piles at the facility and other heavy movements, \$0.15 million for a 85' man
15 lift in order to safely complete necessary work on elevated components at the
16 facility, and \$0.21 million for various capital projects that are each less than
17 \$100,000.

18

19 For Fuel Supply, as described earlier, there is a program to rebuild railcar trucks
20 and draft system components. The railcar capital program extends the trucks and
21 draft systems useful life and operability consistent with expected operations and
22 mitigates future potential railcar repair costs. The costs for these railcar truck and
23 draft system rebuilds during the January 2022 through December 2022 period were
24 \$1.0 million as shown on Exhibit A-12, Schedule B5.2, line 11, column (b).

Line
No.

1 **Q25. What are the projected capital expenditures for MERC and Fuel Supply for**
2 **the 24 months from January 2023 through December 2024 as reflected on**
3 **Exhibit A-12, Schedule B5.2, column (e)?**

4 A25. The total capital expenditures for January 2023 through December 2024 are
5 estimated to be \$2.9 million in total, line 13 column (e). MERC total capital
6 expenditures for this period are projected at \$1.21 million, line 9 column (e) which
7 is a \$1.78 million and 59% reduction from Case No. U-21297. The Company has
8 identified and removed avoidable expenditures since the Case U-21297 filing.
9 MERC capital spend will focus on safety initiatives and replacement of equipment
10 that becomes obsolete or fails and is necessary for continued operations. There are
11 no plans to spend capital on items that are not critical to continued safe,
12 environmentally compliant, and reliable operations consistent with MERC's
13 planned retirement. As detailed on lines 2 through 8 of the Exhibit, the capital
14 projects at MERC for the 24 months ending December 31, 2024 consist of \$0.11
15 million for conveyor belting and associated structures to replace end-of-life
16 equipment, \$0.36 million for large mobile equipment components to replace
17 engines and transmissions per manufacturers' recommendations, \$0.12 million for
18 facility roadways and railroad tracks for safe operations, \$0.16 million for 750KVA
19 & 1500KVA transformers to replace end-of-life equipment, and \$0.46 million for
20 capital projects that are less than \$100,000 each to address based on historical
21 operations and small emergent required capital projects related to maintaining
22 reliable and safe operations.

23

24 As reflected on line 11 of the Exhibit, Fuel Supply continues the project to rebuild
25 railcar trucks and draft system components on cars to extend the trucks' and draft

Line
No.

1 systems' useful life and operability consistent with expected operations and to
2 mitigate future potential railcar repair costs. Fuel Supply is projected to spend \$1.7
3 million on this truck and draft system rebuilding project over the 24-month period
4 January 2023 through December 2024.

5

6 **Q26. What are the projected capital expenditures for MERC and Fuel Supply for**
7 **the projected test period, January 1, 2025, through December 31, 2025, as**
8 **reflected on Exhibit A-12, Schedule B5.2, column (f)?**

9 A26. The total capital expenditures for January 1, 2025, through December 31, 2025, for
10 both entities are estimated to total \$1.2 million. MERC total capital expenditures
11 for this period are projected at \$0.15 million, as detailed on lines 2 through 8.
12 Capital projects currently planned at MERC in the projected test period consist of
13 \$0.05 million for large mobile equipment components to replace engines and
14 transmissions per manufacturers recommendations and \$0.1 million for capital
15 projects that are less than \$100,000 each to address based on historical operations
16 and small emergent required capital projects related to maintaining reliable, safe,
17 and environmentally compliant operations.

18 As reflected on line 11 of the Exhibit, Fuel Supply completes the capital program
19 to rebuild railcar truck and draft systems on railcars to extend their useful life and
20 operability consistent with expected safety regulations, industry norms, reliability,
21 and to mitigate future potential railcar repair costs and unsafe operations. Fuel
22 Supply is projected to spend \$1.0 million on this truck and draft system rebuilding
23 project during the 12-months ending December 31, 2025. As described above,
24 based on expected coal deliveries it is reasonable and prudent to continue the railcar

Line
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1 capital program of \$1 million per year through 2025 but the program will cease
2 after that year.

3 The projected test year capital amount represents a significant reduction from the
4 historical test year, with each projected year being lower than the prior year, as
5 described in Q & A 19.

6

7 **Part III – Fuel Supply and MERC Operations and Maintenance Expenses**

8

9 **Q27. Can you explain the nature of Fuel Supply and MERC operations and**
10 **maintenance expenditures and how declining coal delivery volumes affect the**
11 **economics of those operations?**

12 A27. Fuel Supply's expenditures are primarily for the planning, procurement, and
13 contract administration of the fossil fuel commodities including transportation to
14 plants and the costs to maintain the Company's railcar fleet. The MERC
15 expenditures are primarily for the operation of the coal terminal that processes rail
16 shipments of western coal for lake vessel delivery to DTE Electric's power
17 generation plants in southern Michigan.

18 The decline in the amount of coal being transshipped at MERC results in a higher
19 dollar per ton cost compared to higher volume periods because the reduced fixed
20 operational costs are not being reduced to the extent the tonnage is being lowered.

21

22 **Q28. What does Exhibit A-13, Schedule C5.2, show?**

23 A28. Exhibit A-13, Schedule C5.2, shows historical and projected operation and
24 maintenance (O&M) expenses associated with the Fuel Supply department, on lines
25 1 through 7, and MERC Fuel Handling, on lines 8 through 15.

Line
No.

1 **Q29. What were Fuel Supply and MERC's adjusted historical O&M expenses for**
2 **2022 as shown on Exhibit A-13, Schedule C5.2?**

3 A29. Fuel Supply and MERC Fuel Handling adjusted historical O&M expenses for 2022
4 totaled \$8.3 million as shown in column (f), line 16. This is comprised of \$4.5
5 million for Fuel Supply in column (f), line 7, and \$3.8 million for MERC Fuel
6 Handling in column (f), line 15.

7

8 Fuel Supply O&M expenses include \$0.6 million for operation supervision and
9 engineering, \$0.2 million for miscellaneous steam power expenses, \$0.1 million for
10 maintenance supervision and engineering, and \$1.3 million for maintenance of
11 miscellaneous steam plant in column (f), as well as a Fuel Handling Reclass to
12 O&M of \$2.2 million in column (d) for the Fuel Supply department's portion of
13 Fuel Handling O&M expense recorded in Fuel Account 501.

14

15 MERC's Fuel Handling expenses charged to Fuel Account 501 are shown on lines
16 9 through 14, column (d), which reflect components of fuel handling costs that are
17 reclassified to other expense categories on DTE Electric's adjusted historical
18 financial statements, as explained by Witness Uzenski (see Exhibit A-3, Schedule
19 C.16). Therefore, an adjustment is made in column (e) to remove these cost items
20 from O&M. The remaining amount of \$3.8 million in column (f), line 15 is the total
21 MERC Fuel Handling expenses included in O&M.

Line
No.

1 **Q30. What are Fuel Supply and MERC's Fuel Handling projected O&M expenses**
2 **for the projected test period ending December 31, 2025, as shown on Exhibit**
3 **A-13, Schedule C5.2?**

4 A30. The total projected test period O&M expense is \$8.1 million, comprised of \$4.9
5 million for DTE Electric's Fuel Supply in column (l), line 7, and \$3.2 million for
6 MERC's Fuel Handling in column (l), line 15. These amounts were based on the
7 adjusted historical 2022 O&M expenses adjusted for inflation. The inflation
8 adjustment factors of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 are
9 supported by Company Witness Ms. Uzenski.

10

11 **Q31. Were any adjustments made to derive the January 1, 2025, through December**
12 **31, 2025 projected test period O&M expense ?**

13 A31. Yes, there is an almost \$1 million dollar reduction of the expected O&M for MERC
14 Fuel Handling represented in column (j) line 9. This 23% reduction of MERC's
15 O&M expense, based on the as-adjusted historical test period plus 3 years of
16 inflation (line 15), is a result of the expected savings and avoided costs from
17 decreased transshipment activities (primarily reduced labor and supplies as coal
18 volumes decrease). As with capital, the \$3.2 million of MERC fuel handling O&M
19 represents the minimum expense required to operate the facility safely, reliably,
20 and in an environmentally compliant manner, which helps ensure that critical coal
21 deliveries are made to the Company's power plants.

22

23 **Q32. What are your thoughts regarding the Company's MERC and Fuel Supply**
24 **programs and expenditures?**

Line
No.

1 A32. I believe that the Company's MERC and Fuel Supply programs and expenditures
2 are reasonable and prudent and properly balance the circumstances involved in
3 DTE Electric's transition from coal-fired generation. The Company has reasonably
4 and prudently minimized its MERC and Fuel Supply expenditures to those
5 necessary to maintain safe, reliable, and environmentally compliant operations
6 consistent with its future generation plans.

7

8 **Q33. Does this complete your direct testimony?**

9 A33. Yes, it does.

1 JUDGE WALLACE: All right. Proceed,
2 Mr. Christinidis.

3 MR. CHRISTINIDIS: Yes, your Honor. The
4 Company's next witness is Markus B. Leuker. Mr. Leuker
5 sponsored the Qualifications and Direct Testimony of
6 Markus B. Leuker, consisting of a cover sheet and 31
7 pages of questions and answers. He also sponsors A-5
8 Schedule E1, A-15 Schedule E1, Exhibit A-15 Schedule E2,
9 Exhibit A-15 Schedule E3, Exhibit A-15 Schedule E4,
10 Exhibit A-15 Schedule E-5, and Exhibit A-15 Schedule E6.
11 He does not sponsor any rebuttal testimony. So with
12 that, your Honor --

13 JUDGE WALLACE: Thank you.

14 MR. CHRISTINIDIS: With that, your Honor,
15 the Company would move to bind into the record the
16 Qualifications and Direct Testimony of Markus B. Leuker,
17 and move the admission of Exhibit A-5 Schedule E1, and
18 Exhibit A-15 Schedules E1 through E6.

19 JUDGE WALLACE: Thank you,
20 Mr. Christinidis. Is there any objection to binding in
21 the direct testimony of Mr. Leuker?

22 Hearing none, the testimony is bound in.

23 Is there any objection to the admission
24 of the exhibits and associated schedules identified by
25 Mr. Christinidis? (No response.)

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
DIRECT TESTIMONY
OF
MARKUS B. LEUKER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MARKUS B. LEUKER

Line
No.

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

2 A1. My name is Markus B. Leuker (he/him/his). My business address is: One Energy
3 Plaza, Detroit, Michigan 48226. I am Manager of Corporate Energy Forecasting in
4 the Business Planning and Development organization.

5

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

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

8

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

10 A3. I received a Bachelor of Science in Business Administration from Xavier
11 University in Cincinnati, Ohio with a concentration in Marketing and Management
12 in 1991. I received a Master of Business Administration from Xavier University in
13 Cincinnati, Ohio in 1998. I have also completed several Company sponsored
14 courses and attended various seminars to further my professional development.

15

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

17 A4. I joined the Company in November 2010 as Manager, Corporate Energy
18 Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr.
19 Manager, North American Advisory Services where I led the pursuit, development,
20 execution and delivery of key client projects. Some of my experiences at IHS/CSM
21 Worldwide included: Market Research & Analysis, Market Opportunity Analysis,
22 Business Modeling and Strategic Analysis, Regulatory Market Assessment, and
23 Financial and Scenario Analysis. In addition to my experience with DTE Electric
24 and IHS, I worked as North American Manager, Market Research & Analysis for
25 Visteon Corporation where I managed global coordination of the research function

Line
No.

1 and led a team of researchers in various studies including customer and competitor
2 research, new product creation, and customer satisfaction. I have also had prior
3 experience in the utility industry working as a Senior Analyst at Cinergy
4 Corporation (currently Duke Energy). While at Cinergy, I worked on various non-
5 regulated activities and regulated marketing activities.

6

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

9 A5. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG).
10 The LFG's purpose is to enhance load forecasting capabilities by exchanging
11 information among the group's base of experienced and knowledgeable load
12 forecasters. I am also a member of the Detroit Association for Business Economics
13 (DABE). DABE discusses economic issues affecting Southeastern Michigan.

14

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

16 A6. I am responsible for the development of the economic and electric sales forecasting
17 activities for DTE Electric. These activities include data collection, statistical
18 analysis of data, forecast model building and interaction with other departments on
19 forecast-related activities. My role also includes the preparation of long-term (one
20 year or greater) sales forecasts, short-term (monthly) forecasts, next day forecasts,
21 and the economic forecast that supports the sales forecast.

22

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

25 A7. Yes. I have sponsored testimony in the following cases:

Line
No.

1	U-17049	2012 Energy Optimization Plan
2	U-17097	2013 Power Supply Cost Recovery (PSCR) Plan
3	U-17302	2013 Renewable Energy Plan Update
4	U-17319	2014 PSCR Plan
5	U-17680	2015 PSCR Plan
6	U-17762	2016-17 Energy Optimization Plan
7	U-17767	DTE Electric General Rate Case
8	U-17793	2015 Renewable Energy Plan
9	U-17920	2016 PSCR Plan
10	U-18014	DTE Electric General Rate Case
11	U-18111	2016 Amended Renewable Energy Plan
12	U-18143	2017 PSCR Plan
13	U-18255	DTE Electric General Rate Case
14	U-18262	2018-19 Energy Waste Reduction Plan
15	U-18403	2018 PSCR Plan
16	U-18419	2017 Certificate of Necessity
17	U-18232	2018 Renewable Energy Plan
18	U-20162	DTE Electric General Rate Case
19	U-20221	2019 PSCR Plan
20	U-20471	2019 Integrated Resource Plan (IRP)
21	U-20561	DTE Electric General Rate Case
22	U-18232	2020 Amended Renewable Plan
23	U-20836	2022 DTE Electric Rate Case
24	U-21193	2022 Integrated Resource Plan
25	U-21297	2023 DTE Electric Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to provide the Company's current electric sales,
4 maximum demand and system output forecast for the period 2023-2028, including
5 the projected 12-month test period January 1, 2025 through December 31, 2025. I
6 will discuss the outlook for the national and local economy which is the basis of
7 the forecast. I will describe how the forecast of electric sales, maximum demand
8 and system output is developed. My testimony will support the reasonableness of
9 the electric sales forecast used by DTE Electric in this proceeding.

10

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

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

13	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
14	A-5	E1	Annual Sales by Major Customer Classes and System
15			Output 2018-2022 Historical
16	A-15	E1	Annual Sales by Major Customer Classes and System
17			Output 2023-2028 Forecast
18	A-15	E2	Annual System Output, Maximum Demand and Load
19			Factor
20	A-15	E3	Projected Period Known and Measurable Changes to
21			Sales
22	A-15	E4	Summary of Economic Outlook
23	A-15	E5	Variance of Weather-Normalized Electric Sales and
24			Peak and ITRON's Benchmarking Survey Results

Line
No.

1 in the third. Light vehicle production was 2.6 million in the first quarter and 2.7
2 million in the second.

3

4 **Q13. What is the outlook for the nation's economy in 2024 and 2025?**

5 **A13.** Gross domestic product is expected to increase by 1.3% in 2024 and by 1.6% in
6 2025. Disposable personal income is expected to increase by 2.6% in 2024 and by
7 2.3% in 2025. Personal consumption expenditures are expected to increase by 1.2%
8 in 2024 and by 1.5% in 2025. These measures from the national income and product
9 accounts are in real terms, meaning that inflation has been removed from them. The
10 CPI-U is forecast to increase by 2.7% in 2024 and by 2.4% in 2025. Total light
11 vehicle production in the United States is forecast to reach 10.7 million units in
12 2024 and 11.1 million in 2025.

13

14 **Q14. What is the outlook for Southeast Michigan's economy in 2024 and 2025?**

15 **A14.** Total non-farm employment is forecast to decline by 0.6% in 2024 but increase by
16 0.3% in 2025. Natural resources, mining, and construction employment is expected
17 to decline by 2.5% in 2024 and by 0.7% in 2025. Total private non-manufacturing
18 employment is forecast to decline by 0.2% in 2024 and increase by 0.6% in 2025.
19 In the government sector, employment is expected to rise by 0.7% in 2024 and by
20 0.8% in 2025. Southeast Michigan automotive production is expected to reach a
21 level of 1.5 million vehicles in 2024 and 1.7 million in 2025. Population is forecast
22 to increase by 0.10% in 2024 and by 0.07% in 2025.

Line
No.

1 **Part II: Forecast Development and Assumptions**

2 **Q15. What is the general approach used in developing the forecast of DTE Electric's**
3 **service area electric sales and system output?**

4 A15. The general approach reflects widely accepted industry standards for electricity
5 forecasting, including regression and end-use modeling. Using this approach has
6 resulted in high accuracy rates when comparing forecasted DTE Electric service
7 area electric sales to actual historical annual sales. Forecast accuracy is discussed
8 in more detail in Part IV of my testimony.

9
10 Most customer class sales and customer forecasts are built from linear regression
11 models that relate monthly sales to economic activity, weather, changes in end-use
12 saturation, and energy efficiency. The forecast is developed separately for each
13 major rate classification: Residential, Commercial and Industrial (C&I), and other.
14 The residential sales forecast is derived by combining a use-per-customer forecast,
15 using a statistically adjusted end-use (SAE) specification, with a customer forecast.
16 Separate models are estimated for small and large C&I customers. Small C&I,
17 comprised of over 200,000 small business customers, is modeled similarly to
18 residential, while large C&I, comprised of over 3,000 high consumption large
19 business customers, is forecast using econometric models unique to seven
20 supersectors. The Other (street lighting) forecast is provided by Company Witness
21 Bellini. The system output is forecasted as the sum of the electric sales values and
22 the projected system losses.

23

24 There are many factors that impact the sales and customer forecasts for each
25 customer class. Examples of forecast drivers include:

Line
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- 1 • National, state, and local economic projections provided by sources
- 2 including, but not limited to: S&P Global (formerly IHS Markit), Moody's
- 3 Analytics, and Polk Automotive.
- 4 • The Energy Information Administration (EIA) Annual Energy Outlook
- 5 (AEO) 2022 end-use intensity and end-use saturation estimates for the East
- 6 North Central Census Division (modified to reflect DTE Electric's end-use
- 7 information)
- 8 • Historical weather data from the Detroit Metropolitan Airport, with normal
- 9 weather assumptions in the forecast horizon
- 10 • DTE Electric's Energy Waste Reduction (EWR) targets
- 11 • DTE Electric's behind-the-meter distributed generation (DG) projections
- 12 • DTE Electric's electric vehicle (EV) forecast for light-duty and fleet vehicles
- 13 • Large customer load adjustments that would not be reflected in the historical
- 14 data or economic projections

15

16 **Q16. Can you please describe the data used to construct the forecast models?**

17 A16. Each model used to forecast sales was estimated with monthly historical

18 consumption data beginning in January 2006, with estimation ending in June 2023.

19 Customer count forecast models were estimated with monthly historical customer

20 count data beginning in January 2012, with estimation ending in June 2023.

21

22 The forecast for both sales and customers was extended through 2028 and used to

23 develop the long-term system energy and peak demand forecast.

Line
No.

1 A bottom-up hourly load model, described later in my testimony, utilized hourly
2 historical customer class level data as the basis for developing a suite of load
3 profiles that were used to forecast the peak demand.
4

5 **Q17. How is weather applied in the load forecast?**

6 A17. Weather is one of the primary variables used in each customer class forecast model.
7 In each model, actual weather, measured in the form of heating degree days
8 (HDDs) and cooling degree days (CDDs) is used to understand the unique
9 relationship that a customer class's energy consumption has with weather. HDDs
10 are calculated by subtracting average daily temperature from a defined base such
11 as 65 degrees Fahrenheit. Conversely, CDDs are calculated by subtracting the base,
12 from average daily temperature.
13

14 In regression modeling, a coefficient is calculated to quantify this impact. Once the
15 coefficient is calculated, it is applied to the weather assumed in the forecast horizon.
16 In the forecast horizon, normal weather is assumed as the most prudent form of
17 future weather expectations.
18

19 **Q18. Can you please describe the HDD and CDD bases used in the forecast?**

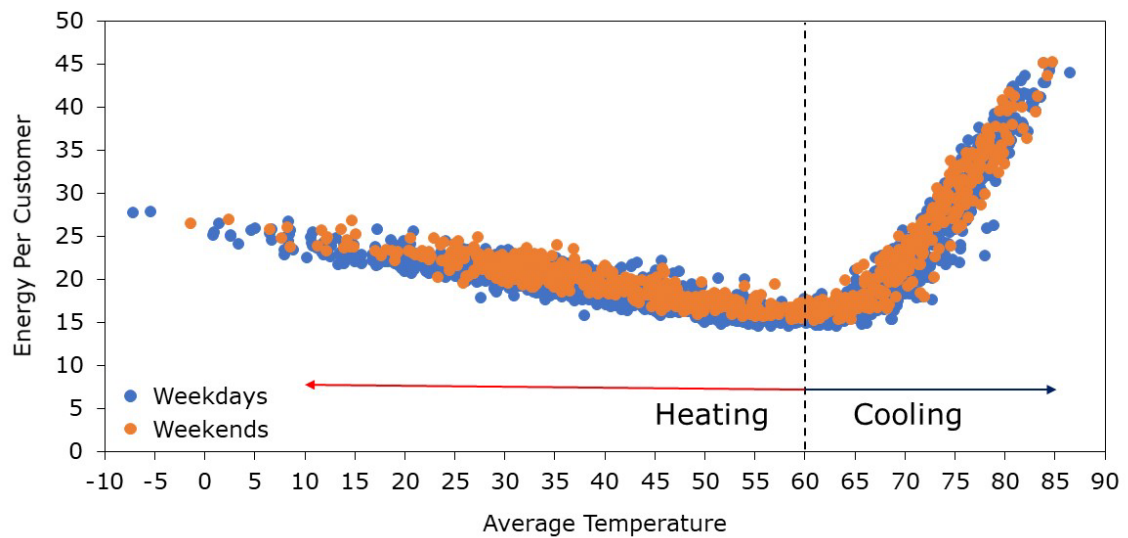
20 A18. As seen in Figures 1 and 2, weather impact is different depending on the customer
21 class. Residential sales are more impacted by weather and customers typically
22 begin cooling their buildings at an average temperature of 60 degrees. Small C&I
23 sales are not as influenced by weather, although customers typically begin cooling
24 their buildings at an average of 50 degrees. The relationships to weather are also
25 non-linear, creating a need to utilize multiple HDD and CDD bases to accurately

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capture the weather response. HDD and CDD bases, represented by the name and temperature of the base, for each customer class include:

- Residential: HDD25, HDD60, CDD60, CDD65, CDD70 and CDD75
- Small C&I: HDD50, CDD50, CDD60, and CDD70
- Large C&I (varies by supersector):
 - Education and Health: CDD50
 - Transportation, Trade and Utilities (TTU): HDD50 and CDD50
 - Offices: HDD45 and CDD55
 - Other Markets: HDD45 and CDD55
 - Automotive: HDD50 and CDD60
 - Other Manufacturing: CDD55

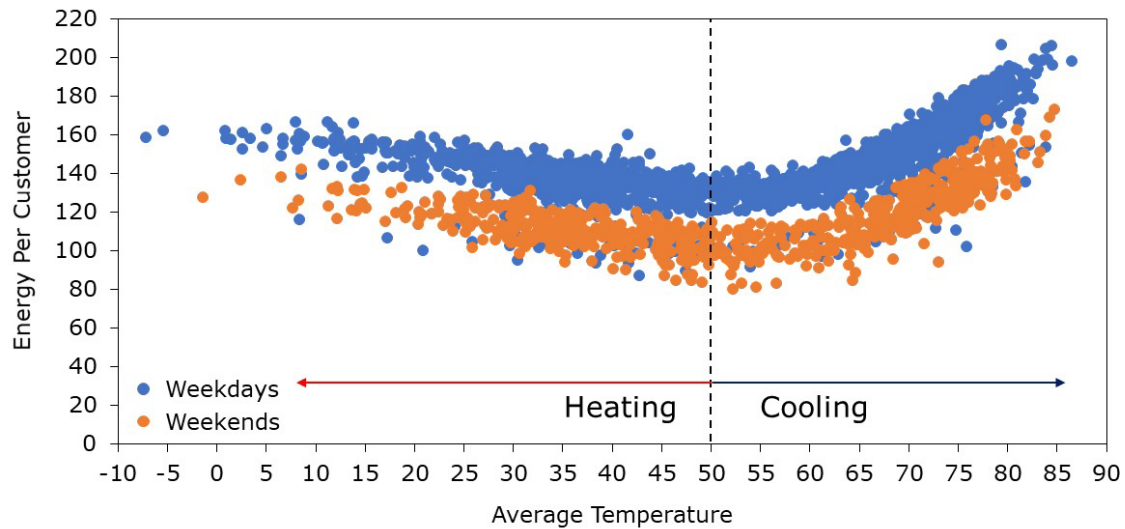
Figure 1 : Residential Daily Use-Per-Customer vs Temperature



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1 **Figure 2 : Small C&I Daily Use-Per-Customer vs Temperature**

2



3 **Q19. How does DTE Electric define normal weather?**

4 A19. DTE Electric defines normal weather as a 15-year average of historical values,
 5 updated on an annual cadence as recommended by the Commission in Case No. U-
 6 20471. In this instant case, 2008-2022 is the timeframe for normal weather.
 7 Additionally, historical actual sales in my Exhibits were weather normalized with
 8 the same normal weather assumed in the forecast for comparison purposes. Daily
 9 average temperature is converted to HDDs and CDDs for various bases and
 10 averaged across years. As a result, this process calculates and defines normal HDDs
 11 and CDDs for various bases in a given day, month and year.

12

13 **Q20. How was the Residential class forecast developed?**

14 A20. Electricity sales in the residential class were forecast using the SAE model which
 15 specifies energy use as a function of 22 end-uses, including DG and EV demand,
 16 along with factors that affect the end-use requirements such as economic activity
 17 and weather. The residential class forecast begins with a standard end-use model,

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1 with appliance saturation projections and average electricity usage per end-use
2 provided by a Company-conducted residential appliance saturation survey and the
3 EIA's AEO 2022 for the East North Central region in which DTE Electric operates.
4 Residential EWR programs are applied directly to the corresponding end-uses in
5 the SAE model. The combination of appliance saturations and average electricity
6 per end-use is indexed and calibrated to the Company's usage per customer for a
7 base year to create an electricity forecast for each end-use.

8

9 Utilization variables, which explain how much an end-use is utilized, are combined
10 with end-use intensities. For residential, the primary variables used to explain
11 utilization are weather, real personal income, population, households, and
12 workplace occupancy. The utilization variables are then combined with the end-
13 use intensities to compute three explanatory variables that are:

- 14 • XHeat – An aggregated heating variable that captures changes in heating end-
15 use saturation and efficiency, and combined with HDDs, economic, and other
16 factors that impact the utilization of heating equipment.
- 17 • XCool – An aggregated cooling variable that captures changes in cooling end-
18 use saturation and efficiency, and combined with CDDs, economic, and other
19 factors that impact the utilization of cooling equipment.
- 20 • XOther – An aggregated base-load variable that captures changes in base-
21 load end-use saturation and efficiency, and combined with number of days in
22 a month, economic, and other factors that impact the utilization of base-load
23 equipment.

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1 Along with seasonal factors, the resulting explanatory variables are then regressed
2 against the Company's residential monthly use per customer sales. The model
3 effectively acts as the statistical adjustment and calibrates the end-use forecast to
4 the Company's historical sales.

5
6 The number of residential customers was forecasted using historical and projected
7 households for southeast Michigan provided by S&P Global. Customer counts are
8 modeled using a regression, with households as the primary explanatory variable.
9 The customer forecast is then multiplied by the use per customer from the SAE
10 model to produce the total residential class sales forecast.

11

12 **Q21. How was the small C&I forecast developed?**

13 A21. Similar to the residential class forecast, small C&I class sales are also forecast using
14 an SAE model, utilizing 11 end-uses including DG and EV demand. Additionally,
15 C&I EWR programs are incorporated directly into the SAE model. The small C&I
16 sales forecast begins with a standard end-use model with saturation projections and
17 average electricity usage per end-use derived from the EIA's AEO 2022 for the
18 East North Central region in which DTE Electric operates. Since small C&I
19 buildings within the DTE Electric service territory consume electricity differently,
20 the projections are weighted by intensity and prevalence of 11 different building
21 types as defined by the EIA. To better calibrate these projections to the Company's
22 service area, employment values are used to weight end-use intensities with the
23 Company's service area employment data. The combination of saturations and
24 average electricity per end-use is indexed and calibrated to the Company's usage
25 per customer for a base year to create an electricity forecast for each end-use.

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1 Utilization variables, which explain how much an end-use is utilized, are combined
2 with end-use intensities. For small C&I, the primary variables used to explain
3 utilization are weather, gross state product, non-manufacturing employment and
4 households. The utilization variables are then combined with the end-use intensities
5 to compute three explanatory variables that are:

- 6 • XHeat – An aggregated heating variable that captures changes in heating end-
7 use saturation and efficiency, and combined with HDDs, economic, and other
8 factors that impact the utilization of heating equipment.
- 9 • XCool – An aggregated cooling variable that captures changes in cooling end-
10 use saturation and efficiency, and combined with CDDs, economic, and other
11 factors that impact the utilization of cooling equipment.
- 12 • XOther – An aggregated base-load variable that captures changes in base-
13 load end-use saturation and efficiency, and combined with number of days in
14 a month, economic, and other factors that impact the utilization of base-load
15 equipment.

16

17 Along with seasonal factors, the resulting explanatory variable is then regressed
18 against the Company's small C&I monthly use per customer sales. The model
19 effectively acts as the statistical adjustment and calibrates the end-use forecast to
20 the Company's historical sales.

21

22 Small C&I customers are modeled using a regression with households used as the
23 primary variable. The customer forecast is then multiplied by the use per customer
24 from the SAE model to produce the total small C&I class sales forecast.

Line
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1 **Q22. How was the large C&I forecast developed?**

2 A22. The large C&I forecast begins by disaggregating all primary service sales into
3 seven distinct supersector markets. Granular market segments defined by the
4 customer's North American Industry Classification System (NAICS) code are
5 aggregated into supersectors defined by the Bureau of Labor Statistics. The seven
6 supersectors are medical and education, transportation, trade, and utility (TTU),
7 offices, other markets, automotive, other manufacturing, and steel.

8

9 Econometric models, a commonly used technique among utility forecasters, are
10 used to forecast sales for the Company's service territory at the supersector level.
11 Individual regression equations are applied to all supersectors, using various
12 explanatory variables such as corresponding supersector employment and gross
13 state product, automotive production, weather, and cumulative EWR savings, to
14 drive the forecast. The regression results are evaluated for reasonableness and
15 validated through various model statistics.

16

17 Regression modeling alone does not account for incremental growth of
18 technologies such as electric vehicles. Unlike residential and small C&I, large C&I
19 is not modeled by end-use. Therefore, it is necessary to make post-regression
20 adjustments to the forecast to incorporate future technology and customer specific
21 closings or expansions. The two main post regression adjustments include EV
22 growth and large customer projects that are informed by customer account
23 managers.

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1 **Q23. Is the method to forecast customer class sales the same as what the Company**
2 **proposed in Case No. U-21297?**

3 A23. For the most part, yes. The underlying methods used to forecast by customer class
4 remain foundationally the same, with only changes to the input data. In general,
5 most changes to the forecast consist of refreshing data sources to reflect the most
6 current outlooks, or routine process updates such as updating the normal-weather
7 period to include the most recent year of data.

8

9 **Q24. What level of EWR is assumed in the forecast?**

10 A24. The load forecast assumes EWR savings consistent with Case No. U-21322 and
11 Case No. U-21193, the Company's most recent EWR Plan and Integrated Resource
12 Plan filings respectively. For 2025, the Company plans to achieve 2% annual
13 savings, made up of a 1.4% reduction in residential sales, and a 2.4% reduction in
14 C&I sales.

15

16 **Q25. What type of DG resources were included in the forecast?**

17 A25. The Company, for purposes of the forecast, is defining DG as customer-sited
18 resources that are: 1) interconnected to the distribution system on the customer's
19 side of the utility's service meter and 2) installed to offset site load with incidental
20 export. For forecasting purposes, the projected additional DG resources were
21 assumed to be solar photovoltaics (PV).

22

23 **Q26. How was the DG outlook applied to the forecast?**

24 A26. The DG outlook was developed utilizing the Company's residential and non-
25 residential interconnection history. The forecast begins with a collection of

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1 historical and projected PV economics for both residential and non-residential
2 customers. Variables such as, but not limited to, capital costs, operating and
3 manufacturing costs, tax credit schedules, and electricity prices were used to
4 determine the PV economics. These economics are used as the primary explanatory
5 variable in a regression model, with the Company's interconnection history as the
6 dependent variable, to project the levels of DG expected in the future.

7

8 Two separate forecasts are produced for residential and non-residential. The
9 historical and forecast DG is applied directly as an additional end-use into the
10 models for residential and small C&I.

11

12 **Q27. How was the EV outlook applied to the forecast?**

13 A27. For the EV forecast, the cumulative vehicle stock forecast presented by Witness
14 Bennett was used as a starting point to estimate the historical and forecasted load
15 in the Company's service territory.

16

17 The EV stock is multiplied by a kWh/vehicle value and the assumed vehicle miles
18 traveled unique to each vehicle segment to arrive at the load associated with the
19 forecasted vehicle volumes. Vehicle segments modeled include battery-electric
20 light-duty vehicles, plug-in hybrid light-duty vehicles, buses, medium-duty trucks,
21 and heavy-duty trucks.

22

23 For light-duty vehicles, the Company's appliance saturation survey suggests
24 approximately 75% of EV charging is done at personal residences while the other
25 25% is done at non-residential locations, such as workplace or public charging
26 stations. Therefore, approximately 75% of the light-duty EV sales forecast was

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1 applied to the residential model as an additional end-use while the remaining was
2 applied to the small and large C&I models as a starting point. Over time, as EV
3 adoption becomes more mainstream, the forecast assumes these dynamics will shift
4 in favor of more non-residential charging. As public infrastructure is built out to
5 support direct current (DC) fast charging and consumers without access to home
6 charging begin to adopt EV's, the boundary between home and public charging is
7 projected to overlap.

8

9 For fleet (medium-duty and heavy-duty) vehicles, 100% of the fleet EV sales
10 forecast was applied to the large C&I model as an incremental adjustment to the
11 forecast.

12

13 **Q28. How was the Electric Choice sales forecast developed?**

14 A28. The Electric Choice sales forecast was based on 10% of retail sales. Historical class
15 ratios are applied to the Electric Choice cap and new customer load is added
16 separately.

17

18 **Q29. How was the DTE Electric system peak demand forecast developed?**

19 A29. A bottom-up hourly load model was used to forecast annual DTE Electric service
20 area and DTE Electric bundled peak demand. This was also utilized to determine
21 monthly peak demands in the forecast period.

22

23 **Q30. What is a bottom-up hourly load model?**

24 A30. A bottom-up approach, put simply, obtains the peak demand forecast by summing
25 hourly values from the bottom-up. Load profiles are developed for each of the sales

Line
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1 classes utilizing the Company's historical hourly AMI data. Residential and small
2 C&I classes were further broken into base, cooling, and heating end-uses which
3 captures changing peak demand levels based on the composition of the underlying
4 load shapes, and changes in end-use consumption. Additional load profiles for
5 technologies such as EVs and DG are also used.

6
7 The profiles are scaled to the monthly energy forecasts by customer class, adjusted
8 for losses, and summed to predict the system total. The highest hourly value in a
9 year or month is the peak forecast. Modeling system peak using a bottom-up
10 approach is advantageous in that it captures load shape diversity. For example, as
11 customers adopt more efficient HVAC units, or technologies such as EVs increase
12 in penetration, a bottom-up approach provides the ability to understand changes in
13 the system peak, as well as the hour in which it occurs.

14

15 **Q31. What temperature assumptions were made regarding the peak demand**
16 **forecast?**

17 A31. Normal temperature on the day of the annual peak is assumed to be 82.3 F, which
18 is the mean temperature at Detroit Metropolitan Airport. This value is based upon
19 an average peak-day mean temperature for a 15-year period (2008 through 2022).
20 The mean temperature is calculated as the average of hourly temperatures for the
21 day. The peak day is assumed to occur on a weekday in July.

22

23 **Q32. Are Demand Response programs included in the Company's peak forecast?**

24 A32. Demand Response programs are not included in the peak forecast. Demand
25 Response programs, such as Interruptible Space-Conditioning, are used to meet

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1 the Company's Midcontinent Independent System Operator (MISO) resource
2 adequacy requirements. Demand Response programs are accounted for on the
3 supply side as load modifying resources.

4

5 **Part III: Historical and Current Electric Forecast Sales and Demand**

6 Section 1: Electric Sales

7 **Q33. When referring to 2023 in this testimony, how many months of actuals are**
8 **included?**

9 A33. When 2023 is referenced in this testimony, it includes ten months of actual sales
10 and two months of forecasted sales.

11

12 **Q34. What has been the compound annual growth rate of DTE Electric sales over**
13 **the last five years?**

14 A34. As shown in Exhibit A-5, Schedule E1, page 4 of 4, weather normalized service
15 area sales from 2018 to 2022 have declined during the five-year historical period.
16 In 2018, total service area sales were 47,362 GWh and 2022 sales were 45,117
17 GWh, representing a compound annual growth rate (CAGR) of -1.2%.

18

19 Bundled sales have decreased from 42,625 GWh in 2018 to 40,631 GWh in 2022,
20 representing a CAGR of -1.2%. The electric choice sales declined from 4,737 GWh
21 in 2018 to 4,486 GWh in 2022, a CAGR of -1.4%. Refer to Exhibit A-5, pages 1
22 through 3 for additional detail regarding historical actual sales for the service area,
23 bundled, and electric choice.

Line
No.

1 **Q35. What are sales for the projected test period, January 2025 through December**
2 **2025?**

3 A35. The service area sales for the projected test period, January 2025 through December
4 2025 are 44,189 GWh and bundled sales are 39,756 GWh. The projected test period
5 service area and bundled sales are displayed in Exhibit A-15, Schedule E1, pages 1
6 and 2, line 3 and electric choice sales are displayed in Exhibit A-15, Schedule E1,
7 page 3, line 2. The projected known and measurable changes for bundled sales from
8 2022 to the projected test year are detailed in Exhibit A-15, Schedule E3.

9

10 **Q36. What is the CAGR of the DTE Electric service area electric sales from 2022**
11 **through the forecast period to 2028?**

12 A36. The service area sales are expected to decrease to 44,170 GWh in 2028. This
13 represents a -0.4% CAGR. The forecast of annual sales and system output for DTE
14 Electric's service area for the years 2023 through 2028 is reflected on Exhibit A-
15 15, Schedule E1, page 1 of 3.

16

17 **Q37. What is the CAGR of DTE Electric bundled electric sales from 2022 through**
18 **the forecast period to 2028?**

19 A37. The bundled sales are projected to decrease over the forecast period, consistent with
20 the declining trend seen in the historical data. The bundled sales are expected to
21 decline to 39,786 GWh in 2028. This represents a -0.3% CAGR. The current
22 forecast of bundled sales and system output for the years 2023 through 2028 are
23 shown on Exhibit A-15, Schedule E1, page 2 of 3.

Line
No.

1 **Q38. What is the CAGR of Electric Choice sales from 2022 through the forecast**
2 **period to 2028?**

3 A38. Electric Choice sales are expected to decrease to 4,383 GWh in 2028. This
4 represents a -0.4% CAGR. The current forecast of electric choice sales and system
5 output for the years 2023 through 2028 are shown on Exhibit A-15, Schedule E1,
6 page 3 of 3, line 7.

7
8 **Q39. What is the outlook for residential class sales?**

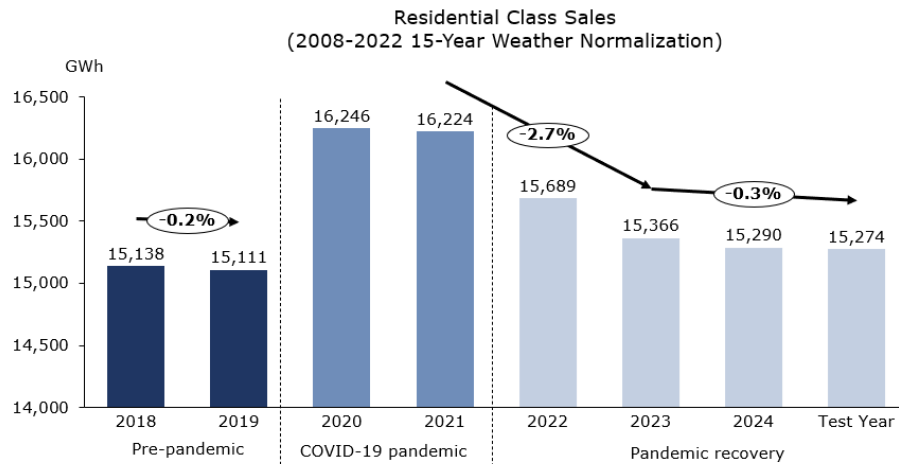
9 A39. DTE Electric's service area residential Class sales are forecast to decline -0.3%
10 annually, on average, between 2023 and the 2025 projected test period in the instant
11 case. As seen in Figure 3, residential sales experienced a sharp increase in sales
12 from 2019 to 2020 as a result of work from home policies implemented due to the
13 COVID-19 pandemic. Residential sales continued to remain elevated through 2021
14 and have since been on a downward trajectory as more people begin to navigate
15 back to in-person work. From 2021 through October of 2023 (ten months of actuals
16 and two months of forecast), residential sales have declined at a -2.7% CAGR. As
17 hybrid work arrangements are continuing to stabilize¹, residential sales are
18 expected to follow a similar trajectory through the projected test period as they did
19 pre-pandemic. Figure 3 shows that from 2018 to 2019 residential sales declined at
20 a -0.2% CAGR, while sales from 2023 to the projected test year are expected to
21 decline at -0.3% CAGR. Modest average annual growth of 0.4% in residential
22 customer count is expected from 2022 through 2028 due to a moderating housing
23 market. Annual customer counts are shown in Exhibit A-15, Schedule E6. Use-

¹ The Future of the Office Has Arrived: It's Hybrid (gallup.com) available at
<https://www.gallup.com/workplace/511994/future-office-arrived-hybrid.aspx>, accessed on 1/3/2024

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per-customer from 2022 through 2028 is expected to decrease by 0.5% annually on average. For a graphical view of the residential forecast, refer to Figure 3 below.

Figure 3 : Residential Forecast



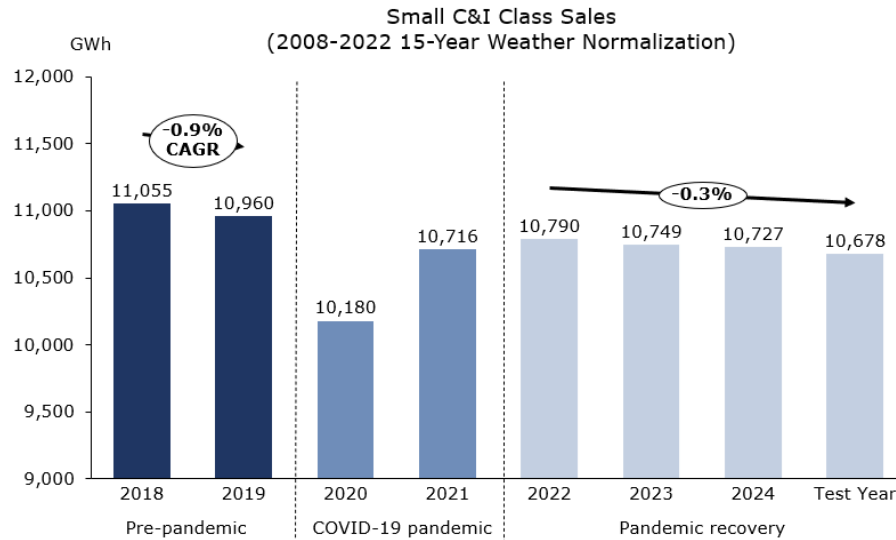
Q40. What is the outlook for small C&I class sales?

A40. DTE Electric's service area small C&I class sales are forecast to decrease -0.3% annually, on average, between 2022 and the 2025 projected test period. The CAGR for 2022 through the 2025 projected test year is consistent with the CAGR of -0.9% observed in pre-pandemic years of 2018-2019. Inversely to residential, small C&I sales declined in 2020 as a result of various policies implemented due to the COVID-19 pandemic. From 2020-2022 sales recovered as policies implemented on commercial business such as restrictions on in-person events were lifted and more people returned to in-person work. Through 10 months of 2023, sales have stabilized around 2022 levels, mainly due to the conclusion of restrictive policies from COVID-19 in June of 2021, combined with stabilizing hybrid work arrangements. Modest average annual growth of 0.4% in Small C&I customer count is expected from 2022 through 2028 due to modest residential customer growth. Use-per-customer from 2022 through 2028 is expected to decrease by -0.7% annually on average. Growth in the Small C&I class is constrained by the increase

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in energy efficiency programs targeting Commercial and Industrial customers bundled with limited economic growth in the near term. For a graphical view of the small C&I forecast, refer to Figure 4 below.

Figure 4 : Small C&I Forecast



Q41. What is the outlook for large C&I class sales?

A41. DTE Electric's service area large C&I class sales are expected to decrease by 0.7% annually, on average, from 2022 to the projected test period in this instant case. As mentioned previously, Large C&I class sales are allocated between seven supersector markets: education and health, trade, transportation, and utilities (TTU), offices, other markets, automotive, steel and other manufacturing. The decrease in sales is primarily due to projected declines in TTU and manufacturing employment from 2023 to 2025 affecting the largest supersectors in large C&I. The declines in the employment values are due to slowing demand and inventory levels caught up from supply chain issues over the past three years. Furthermore, increased energy efficiency initiatives targeting C&I customers minimizes positive

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1 employment projections in the smaller supersectors; education & health, offices,
2 and other markets. Table 1 shows the 2023-2025 CAGRs for the employment
3 drivers including in Exhibit A-15, Schedule E4, used in each supersectors'
4 regression model.

5

Table 1 Large C&I Employment CAGRs

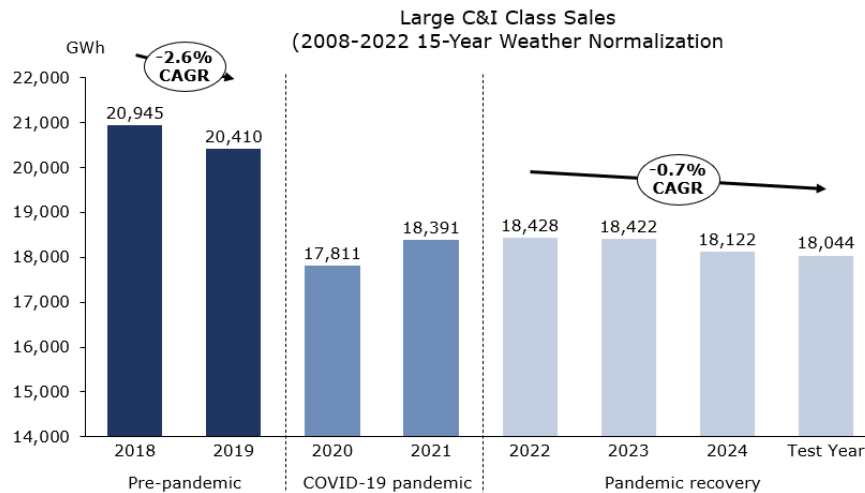
Economic Index	2023-2025 CAGR
Education & Health Employment	1.7%
TTU Employment	-4.0%
Office Employment	1.9%
Other Markets Employment	3.1%
Manufacturing Employment	-5.3%

6

7 As seen in Figure 5, the decreasing trend in sales observed pre-pandemic are
8 expected to continue, although at a slower rate. The CAGR for 2022 to the 2025
9 projected test period is -0.7% which is less of a decline than the CAGR of -2.6%
10 observed in pre-pandemic years of 2018-2019. For a graphical view of the large
11 C&I forecast, refer to Figure 5 below.

Line
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Figure 5 : Large C&I Forecast



Q42. What is the outlook for other class sales?

A42. DTE Electric's service area Other Class sales are expected to decrease 1.5% annually, on average, from 2022 through 2028. The Other Class consists of street lighting and traffic signals. The main reason for the decline in sales is the use of more energy efficient lighting. For further detail on street lighting see the testimony of Company Witness Bellini.

Section 2: Electric Peak Demand

Q43. What has been the CAGR of DTE Electric peak demand for the historical period 2018-2022?

A43. As shown in Exhibit A-5, Schedule E1, page 4 of 4, the service area peak demand in 2018 was 11,344 MW and 2022 peak demand was 10,959 MW, representing a CAGR of -0.9%. The bundled peak demand was 10,447 MW in 2018 and 10,207 MW in 2022 at a CAGR of -0.6%.

Line
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1 **Q44. What are the system output and annual peak demand for the projected test**
2 **period, January 2025 through December 2025?**

3 A44. The service area system output and annual peak demand for the projected test
4 period, January 2025 through December 2025 are 47,341 GWh and 10,911 MW,
5 respectively. The projected test period bundled system output and annual peak
6 demand are 42,683 GWh and 10,157 MW, respectively. The service area and
7 bundled system outputs and peak demand can be found on Exhibit A-15, Schedule
8 E2, pages 1 and 2, line 8. The Electric Choice impact is displayed in Exhibit A-15,
9 Schedule E2, page 2 of 2. Low (10%) and high (90%) confidence bands on
10 forecasted summer peak demand are provided for DTE Electric's service area and
11 DTE Electric's bundled sales levels and can be found on Exhibit A-15, Schedule
12 E2, pages 1 and 2.

13

14 **Q45. What is the CAGR of the DTE Electric service area system peak demand from**
15 **2022 over the forecast period to 2028?**

16 A45. As shown in Exhibit A-15, Schedule E2, page 1 of 2, DTE Electric's temperature
17 normalized service area peak demand declines from 10,959 MW in 2022 to 10,905
18 MW in 2028, representing a CAGR of -0.1%. The decline in peak demand is
19 mainly due to a decline in residential air-conditioning electricity sales, which is
20 projected to decline 1.6% on average annually, due to increased efficiency.

21

22 **Q46. What is the CAGR of the DTE Electric bundled peak demand from 2022 over**
23 **the forecast period to 2028?**

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1 A46. DTE Electric's bundled peak demand forecast declines from 10,207 MW in 2022
2 to 10,151 MW in 2028, representing a CAGR of -0.1%. The bundled peak demand
3 forecast from 2023 to 2028 is shown in Exhibit A-15, Schedule E2, page 2 of 2.
4

5 **Part IV: Electric Load Forecast Accuracy**

6 **Q47. How are DTE Electric's sales forecast and methodologies validated?**

7 A47. DTE Electric's service area sales forecast is tracked annually, and the Company
8 continuously checks the accuracy of the sales forecast models. For example, as
9 shown in Exhibit A-15, Schedule E5, page 1, the DTE Electric total service area
10 forecast in 2022 was 45,306 GWh (line 13). Total weather-normalized service area
11 sales (adjusted for normal weather assumed in that year) in 2022 were 45,081 GWh
12 (line 6). This represents a 99.5% accuracy for the 2022 total sales forecast. On
13 average, for historical years 2018 through 2022, the absolute percent variance for
14 the total sales forecast is 1.87% using the Company's forecasting methods, as
15 shown in Exhibit A-15, Schedule E5, page 1.
16

17 **Q48. Which Company forecast was used for the accuracy measures used in Exhibit**
18 **A15, Schedule E5? Why?**

19 A48. The Company uses the last forecast produced in a given calendar year as the basis
20 for the accuracy measurement shown in Exhibit A-15, Schedule E5. For example,
21 the Company typically produces a forecast in Q4 of any given calendar year for the
22 next calendar year sales. This forecast was chosen as the basis for accuracy to most
23 closely resemble the forecasts submitted by peer utilities in the ITRON
24 Benchmarking analysis referenced in Q51.
25

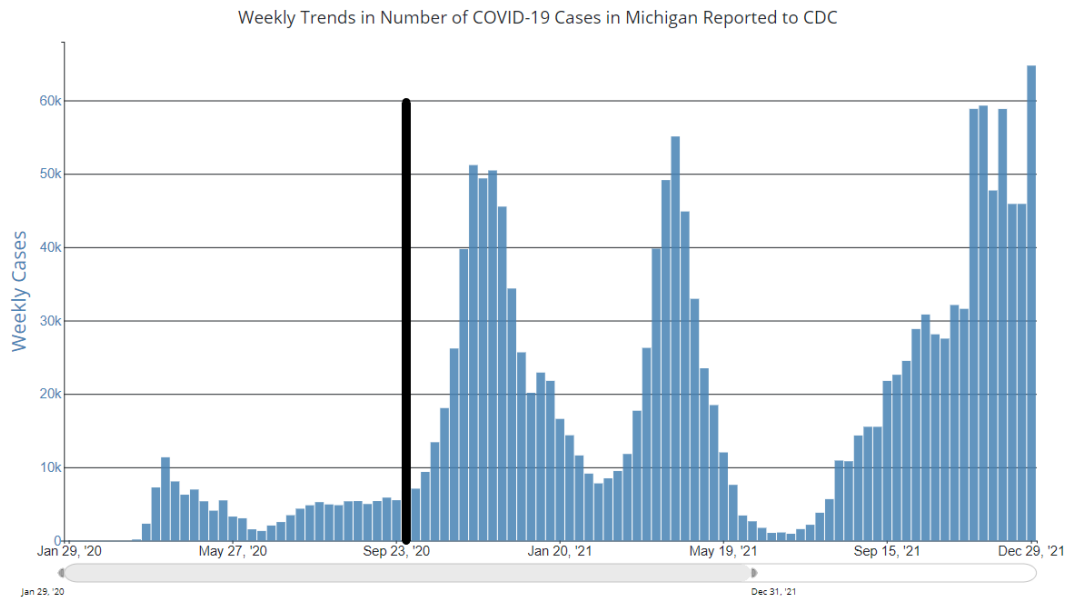
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1 **Q49. Can you explain the deviation in accuracy experienced in 2020 and 2021, as**
2 **shown in Exhibit A-15, Schedule E5, page 1?**

3 A49. The forecast for 2020 was completed in 2019, before the COVID-19 pandemic
4 began to impact the United States. In March 2020, the spread of COVID-19 caused
5 a shift in electricity consumption throughout DTE Electric's service territory.
6 Commercial and industrial sales fell due to business closures from government
7 mandates while residential sales increased as a result of work from home policies
8 enacted to mitigate the spread of COVID-19. As seen in Figure 6, mid-way through
9 2020, case counts of COVID-19 began to stabilize which led to business activity
10 attempting to gradually resume pre-pandemic operations. While still uncertain, it
11 appeared that the effects of COVID-19 likely began to subside through the rest of
12 2020 and into 2021. The forecast for 2021 was completed in the third quarter of
13 2020, marked in black in Figure 6, just prior to the rise in cases caused by the
14 emergence of the Delta variant. The sharp spike in cases experienced in the fourth
15 quarter of 2020, as well as the subsequent waves experienced in 2021 caused more
16 business closures, as well as continued work from home policies, ultimately
17 creating sustained sales variances through 2021. This was contrary to what the
18 trends in the data suggested at the time that the 2021 forecast was completed.

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1

Figure 6 : Michigan COVID-19 Case Counts 2020 & 2021

2

3 **Q50. How has the Company's forecast accuracy performed in the periods following**
 4 **the COVID-19 pandemic?**

5 A50. As seen on Exhibit A-15, Schedule E5, page 1 of 2, Line 20 and 22, the Company
 6 achieved an absolute percent variance of 0.50% in 2022 (99.5% accurate) and is on
 7 track to achieve 0.76% in 2023 (99.2% accurate) which is based off 10 months of
 8 historical data. When excluding 2020 and 2021 data from the historical averages,
 9 the Company's average absolute percent variance for years 2018, 2019, 2022, and
 10 2023 is 0.94%, representing 99.1% accuracy. The results for 2022 and 2023 are in-
 11 line or better than the pre-pandemic results achieved in 2018 and 2019.

12

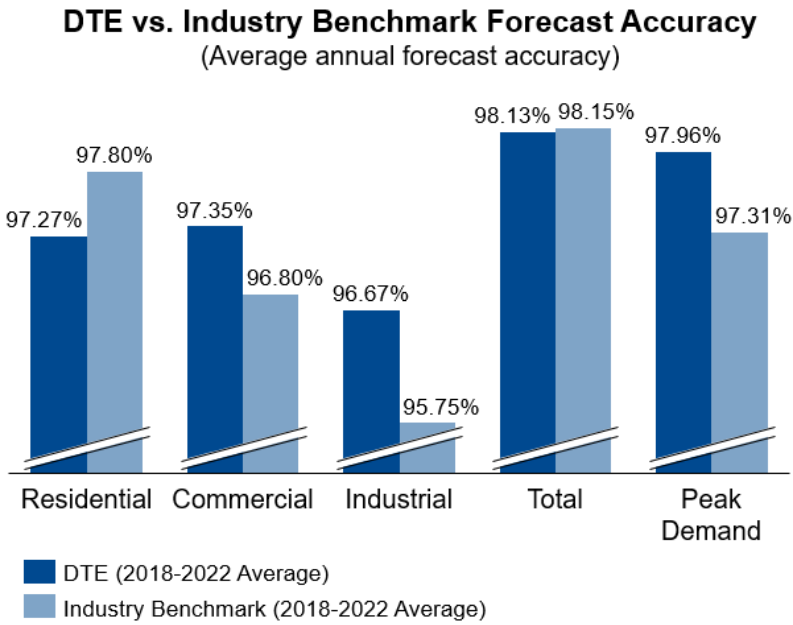
13 **Q51. Does the Company perform any benchmarking on forecast accuracy?**

14 A51. Yes. The Company conducts benchmarking activity by researching forecast
 15 accuracy studies. A study, conducted by ITRON in 2023 is shown in Exhibit A-

Line
No.

1 15, Schedule E5, page 2. DTE Electric is on par with peer utilities across the nation
2 in forecasting by customer class and peak demand, as shown in Figure 7 below.
3

4 **Figure 7 : DTE Electric vs. ITRON Forecast Accuracy Benchmark**



5
6 **Q52. Does this complete your direct testimony?**
7 A52. Yes, it does.

1 JUDGE WALLACE: All right. Next.

2 MR. CHRISTINIDIS: Thank you, your Honor.

3 The Company's next witness is Jeffrey C. Davis.

4 Mr. Davis sponsored the Qualifications and Direct
5 Testimony of Jeffrey C. Davis, which consists of a cover
6 sheet and 77 pages of questions and answers. Mr. Davis
7 also sponsored the Rebuttal Testimony of Jeffrey C.
8 Davis, consisting of a cover sheet and 34 pages of
9 questions and answers. Mr. Davis sponsored the direct
10 exhibits and schedules as follows: He sponsors Exhibit
11 A-12 Schedule B5.3, Exhibit A-13 Schedule C5.3, Exhibit
12 A-13 Schedule C5.16, Exhibit A-20 Schedule J1, and
13 Exhibit A-20 Schedule J2. He also sponsors the following
14 exhibits and schedules associated with his rebuttal
15 testimony: That exhibit is Exhibit A-47 Schedule LL1 and
16 Schedule LL2. So with that, your Honor, the Company
17 would move to bind into the record the Qualifications,
18 Direct Testimony, and Rebuttal Testimony of Jeffrey C.
19 Davis, and move the admission of the exhibits and
20 schedules I described.

21 JUDGE WALLACE: Thank you,
22 Mr. Christinidis. Is there any objection to -- I'm
23 sorry, I wrote this down, is it Dennis, Mr.?

24 MR. CHRISTINIDIS: Davis.

25 JUDGE WALLACE: Davis. O.K., that makes
Penn Reporting, LLC - lori.penn@yahoo.com

1 sense. Is there any objection to binding in the direct
2 and rebuttal testimony of Mr. Davis?

3 Hearing none, the testimony is bound in.

4 Is there any objection to any of the
5 exhibits or schedules that Mr. Christinidis identified?

6 (No response.)

7 (Testimony bound in.)

8 - - -

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
DIRECT TESTIMONY
OF
JEFFREY C. DAVIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JEFFREY C. DAVIS

Line
No.

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

2 A1. My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North Dixie
3 Highway, Newport, Michigan, 48166. I am employed by DTE Electric Company at
4 the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic Business Operations.

5

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

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

8

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

10 A3. I graduated from the University of Michigan with bachelor's degrees in nuclear
11 engineering and radiological sciences (NERS) and engineering physics. I have also
12 earned a master's degree and doctorate in NERS from the University of Michigan.

13

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

15 A4. I have been employed by DTE Energy since 2008. Prior to my current position, I
16 was Manager – Nuclear Strategy and Business Support with responsibility for
17 developing the strategic financial plan and goals for the Nuclear Generation
18 organization. From 2008-2015, I was a principal financial analyst with
19 responsibility for budgeting, forecasting, and reporting operations and maintenance
20 (O&M) and capital expenditures for the Nuclear Generation organization.

21

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

24 A5. I am a member of the American Nuclear Society.

25

Line
No.

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

2 A6. I am responsible for advancing the strategic financial and operational plan and goals
3 for the Nuclear Generation organization.

4

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

7 A7. Yes. I have sponsored testimony in the following cases:

8 U-20203 2018 Power Supply Cost Recovery (PSCR) Reconciliation

9 U-20528 2020 PSCR Reconciliation

10 U-20162 2018 DTE Electric Rate Case

11 U-20561 2019 DTE Electric Rate Case

12 U-20836 2022 DTE Electric Rate Case

13 U-21297 2023 DTE Electric Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to discuss and support the reasonableness of the
4 Company's actual nuclear O&M and capital expenditures for the 12-month
5 historical test period ended December 31, 2022. I will also discuss and support the
6 reasonableness of the projected nuclear O&M and capital expenditures for the
7 bridge forecast period and the 12-month projected test period ending December 31,
8 2025. In addition, I will discuss and support the reasonableness of the projected
9 Nuclear Surcharge for the projected test period ending December 31, 2025.

10

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

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

13	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
14	A-12	B5.3	Projected Capital Expenditures - Nuclear Production
15			Plant and Nuclear Fuel
16	A-13	C5.3	Projected Operation and Maintenance Expenses -
17			Nuclear Power Generation
18	A-13	C5.16	Nuclear Power Generation - Projected PERC O&M
19			Expenditures
20	A-20	J1	Proposed Nuclear Surcharge Projected Test Period –
21			12 Months Ending December 31, 2025
22	A-20	J2	Nuclear Plant Capital Project Detail –
23			Routine and Small Projects

24

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

Line
No.

1 A10. Yes, they were.

2

3 **Q11. How do you plan to proceed with your testimony?**

4 A11. I will begin my testimony with the Nuclear Generation capital expenditures;
5 discussing and supporting the actual capital expenditures for the historical test year
6 ended December 31, 2022, the projected capital expenditures for the bridge forecast
7 period and the 12-month projected test period ending December 31, 2025. I have
8 divided my Nuclear Generation capital expenditure discussion into five sections of
9 expenditures: Routine and Small Projects, Non-Routine and Large Projects, Nuclear
10 Fuel, Allowance for Funds Used During Construction (AFUDC), and Plant Activity
11 (removal costs, plant in service and CWIP).

12

13 I will then discuss and support the actual O&M expenses for the historical test year
14 ended December 31, 2022 and the forecasted O&M expenses for the 12-month
15 projected test period ending December 31, 2025 for Nuclear Generation. I have
16 divided the Nuclear Generation O&M expenses discussion into three sections: rate
17 case adjustments, adjusted historical test period and projected adjustments.

18

19 I will then discuss and support the Nuclear Surcharge for the 12-month projected
20 test period ending December 31, 2025 for Nuclear Generation.

21

22 The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC)
23 to operate through 2045. The capital and O&M expenditures discussed for the
24 historical and projected test periods throughout my testimony reflect appropriate

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1 measures to ensure safe and reliable operation of the Fermi 2 Power Plant through
2 2045.

3

4 **Nuclear Generation Capital Expenditures**

5 **Q12. Can you provide an outline of your Nuclear Generation capital expenditures**
6 **discussion?**

7 A12. My testimony will begin with the 2022 – 2025 Capital Projects Overview and then
8 discuss and support the additional details regarding:

- 9 • Routine and Small Projects
- 10 • Non-Routine and Large Projects
- 11 • Total Nuclear Fuel
- 12 • AFUDC Forecast
- 13 • Plant Activity (Removal Costs, Plant in Service and CWIP)

14

15 **2022 - 2025 Capital Projects Overview**

16 **Q13. Can you provide an overview of the Nuclear Generation capital expenditures**
17 **you support?**

18 A13. I refer you to Exhibit A-12, Schedule B5.3, page 1 which depicts the actual capital
19 expenditures for the historical test year ended December 31, 2022, projected capital
20 expenditures for the bridge forecast period and projected capital expenditures for
21 the 12-month projected test period ending December 31, 2025.

22

23 Total capital expenditures are composed of Routine and Small Projects, Non-
24 Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual
25 capital expenditures for historical test year ended December 31, 2022, totaled

Line
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1 \$257.8 million as shown on line 11, column (b) of the exhibit. Nuclear Generation
2 forecasts total capital expenditures for the projected bridge forecast period at \$451.5
3 million as shown on line 11, column (e) and for the 12-month projected test period
4 ending December 31, 2025 at \$215.9 million as shown on line 11, column (f).

5

6 I describe and support a portfolio of discrete reasonable and prudent projects and
7 capital fuel expenditures which provides the basis for the historical actual and
8 forecasted Total Capital Expenditures for January 1, 2022 through December 31,
9 2025.

10

11 **Q14. How do the historical actuals for the 12-month period ending December 31,**
12 **2022, compare to the Nuclear Generation capital (including nuclear fuel)**
13 **expenditures authorized for the same period in the U-21297 rate case?**

14 A14. The U-21297 Order authorized Nuclear Generation capital expenditures at \$258.7
15 million for the 12-month period ending December 31, 2022. The actual Nuclear
16 Generation capital expenditures for the same period were \$257.8 million. The total
17 variance is approximately 0.3% of projected total Nuclear Generation capital
18 expenditures for the reference period.

19

20 **Q15. What was the Commission treatment of DTE Electric Nuclear Generation**
21 **capital expenditures in U-21297 Order, dated December 1, 2023?**

22 A15. DTE Electric's Nuclear Generation capital expenditures depicted in U-21297 were
23 generally accepted and allowed for recovery.

24

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1 However, the Commission also appropriately approved an accounting shift
2 associated with Main Unit Generator Replacement project expenditures (depicted
3 on line 2 of Exhibit A-12, Schedule B5.3, page 4) from rate base to construction
4 work in progress (CWIP) because of the revised timing of the main unit generator
5 installation. Final installation of the main unit generator has been moved from
6 Refueling Outage 22 (RF22) (Spring 2024) to RF23 (Spring 2026).

7

8 **Q16. Is it fair to conclude the Commission has already had the opportunity to review**
9 **DTE Electric's Nuclear Generation historical actuals for the 12-month period**
10 **ending December 31, 2022 in U-21297?**

11 A16. Yes. When DTE Electric filed Case No. U-21297 in 2023, the projected 12-month
12 period ending December 31, 2022, had included ten months of actuals and only two
13 months of forecast. Most notably, as RF21 completed in May 2022, RF21 projects
14 expenditures were complete, known and actuals already included in the expenditures
15 depicted in U-21297 Exhibit A-12, Schedule B5.3; therefore, I will focus on
16 highlighting projects that are more significant in the bridge and projected test years.

17

18 **Q17. Before you discuss the discrete projects, can you summarize the principles and**
19 **conduct of asset maintenance at a nuclear generation unit such as Fermi 2?**

20 A17. Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the
21 nuclear industry. Our operational and strategic decisions preserve this priority.

22

23 **Q18. What do you mean by nuclear safety?**

Line
No.

1 A18. Nuclear safety is focused on ensuring that we maintain and operate the Fermi 2
2 nuclear asset with a high degree of rigor. Conservatism is necessary to minimize
3 risk and ensure the safe and reliable use of nuclear material.

4

5 **Q19. How does DTE Electric manage nuclear safety risk?**

6 A19. DTE Electric manages nuclear safety risk through proper training, procedures and
7 governance, operating the plant consistent with Fermi 2's Nuclear Regulatory
8 Commission (NRC) operating license, operating the plant using the traits of a
9 healthy nuclear safety culture (outlined in the World Association of Nuclear
10 Operators (WANO) Principles PL 2013-1), and maintenance of the asset to support
11 operation through 2045.

12

13 **Q20. What are the key principles the DTE Electric organization uses for maintaining**
14 **the nuclear asset?**

15 A20. I would summarize our key maintenance principles as:

16 1. Implementation of inspection, surveillance, maintenance and project activities
17 are proactive and condition- or time-based to preclude a failure. Unanticipated
18 equipment failures challenge plant operators and result in unplanned shutdowns
19 or derates of the unit; our strategies are designed to minimize the probabilities
20 of unanticipated equipment failures.

21 2. Work such as capital replacements and modifications are implemented when the
22 plant is in the safest condition to do so. For most of our work at Nuclear
23 Generation, that safest condition is when the Fermi 2 plant is shut down for a
24 refueling outage.

Line
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- 1 3. Work such as capital replacements and modifications are planned and executed
2 in a reasonable and prudent manner consistent with the other key maintenance
3 and project management principles.

4

5 **Q21. Why is it safest to perform maintenance on the Fermi 2 plant during a refueling**
6 **outage?**

7 A21. Refueling outages are the safest time to perform maintenance for the following
8 reasons:

- 9 1. Nuclear safety - our operating license issued by the NRC requires the plant to be
10 shut down prior to taking many systems out of service for maintenance. These
11 licensing requirements align with minimizing risks to health and safety.
- 12 2. Personnel safety – many areas of the plant are behind locked doors during
13 operations due to the radiological or atmospheric conditions of the area.
14 Refueling outages offer opportunities to access these otherwise inhospitable
15 areas of the plant for maintenance.

16

17 **Q22. What is the cadence for the Fermi 2 plant refueling outages?**

18 A22. The Fermi 2 plant operates on a 24-month cycle, meaning every 24 months the
19 Fermi 2 plant shuts down for a refueling outage. The Fermi 2 refueling outages are
20 numbered sequentially and named as such: our winter/spring 2022 refueling outage,
21 which was Fermi 2's twenty-first refueling outage, was named Refueling Outage 21
22 or RF21 and Fermi 2's twenty-second refueling outage scheduled in the spring of
23 2024 (approximately 24 months after RF21) is named Refueling Outage 22 or RF22.

24

25 **Q23. What is the typical planning cadence for a Fermi 2 plant refueling outage?**

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1 A23. Refueling outages are highly complex and require an integrated work plan to execute
2 thousands of activities in a relatively short duration.

3

4 Planning for a refueling outage is generally a two-year effort with many intermediate
5 milestones guiding the planning effort; completion of these milestones requires
6 consideration of the existing and projected material condition of the Fermi 2 Power
7 Plant as well as any practical constraints for safe execution of the projected work.
8 The two most relevant of these milestones for capital expenditures are (1) two years
9 prior to the refueling outage (T-24 months), Nuclear Generation confirms the Non-
10 Routine and Large Projects for implementation in the outage and (2) at one year
11 prior to the refueling outage (T-12 months), Nuclear Generation confirms for the
12 Routine and Small Projects to be completed in the outage.

13

14 **Q24. How does the highly complex and integrated characteristic of refueling outage**
15 **work impact project planning and execution?**

16 A24. Projects implemented during refueling outages are not stand-alone, independent
17 projects as one may typically think of projects.

18

19 For example, plant workers such as plant operators, radiation protection, building
20 trades and supervision are not dedicated to individual projects but must be shared
21 across different projects and maintenance because qualified nuclear professionals
22 are finite, nuclear standards are exacting, and gaining clearance to work at a U.S.
23 nuclear plant is non-trivial; suppliers performing work must be chosen to globally
24 improve outage execution - selecting suppliers as if projects were independent

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1 would lead to more expensive work, unnecessary duplication of oversight and
2 potential conflicts between suppliers.

3

4 As a second example, projects and maintenance activities may only occur in a
5 specific schedule sequence which means performance of one project may impact
6 performance of another project or projects.

7

8 As I said, this coordination of work and resources is important to finalizing refueling
9 outage plans and takes place in the cycle leading up to the refueling outage.

10

11 **Q25. How are suppliers chosen to globally improve work execution?**

12 A25. Suppliers of nuclear equipment, components and services are relatively limited and
13 serve a relatively small group of U.S. nuclear power stations. As of December 31,
14 2023, 93 U.S. commercial nuclear reactors were in commercial operations - and
15 consolidation of suppliers is such that in many instances only one or two suppliers
16 are qualified to provide certain nuclear components, equipment or services to
17 nuclear power plants. Fermi 2 is further unique in that the plant is a General Electric
18 Boiling Water Reactor Type 4 design (GE BWR/IV) with a Mark I containment
19 structure and English Electric turbine/generator system. To be reasonable and
20 prudent, selecting suppliers generally requires DTE Electric to weigh more than just
21 the competitively bid costs: DTE Electric must consider supplier qualifications,
22 safety record, original equipment manufacturer (OEM) status, incumbency, market
23 share, industry operating experience and industry feedback, locality, ownership,
24 union status and integration with the local building trades (if applicable), proposed
25 schedule and costs, terms and conditions, likelihood of outcomes, amongst other

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1 factors. If a new participant enters a market, then supporting overall market
2 competition can become a factor as well.

3

4 In general, DTE Electric secures long-term supplier agreements for Fermi 2 nuclear
5 fuel, reactor services, turbine services, major maintenance services, heavy
6 construction services, radiation protection services and engineering design services
7 through competitive supplier sourcing and negotiation. Individual projects can then
8 source, as needed, suppliers using these long-term agreements which facilitates each
9 major supplier's resources being integrated into the overall work plan. DTE Electric
10 sources other components, equipment and services in a reasonable and prudent
11 manner consistent with the factors I outlined above.

12

13 **Routine and Small Projects Capital Expenditures**

14 **Q26. Can you further explain the Routine and Small Projects summarized on line 2**
15 **of Exhibit A-12, Schedule B5.3, page 1?**

16 A26. Routine and Small Projects are those capital expenditures associated with
17 maintaining the various assets that support the safe operation of Fermi 2 and
18 includes work such as pump, motor, valve and reactor control component
19 replacements and can typically be expressed in number of units replaced. Routine
20 and Small Projects are reasonable and prudent because these types of projects
21 address commonly activated and used equipment that are the core of our proactive
22 maintenance regime to maintain nuclear safety. Proactive replacement of these
23 Fermi 2 components is essential to prioritizing nuclear safety by minimizing the
24 potential for unanticipated or unrecoverable failures during plant operation.

25

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1 Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small
2 Projects that support page 1, line 2.

3

4 **Q27. Can you explain the Routine and Small Projects detailed in Exhibit A-12,**
5 **Schedule B5.3, pages 2-3?**

6 A27. Exhibit A-12, Schedule B5.3, pages 2-3 show the by-project capital expenditures
7 for Routine and Small Projects for the historical test year and the projected
8 expenditures for the 24-month bridge forecast period ending December 31, 2024
9 and the 12-month projected test period ending December 31, 2025 which total \$81.3
10 million, \$135.2 million and \$42.5 million respectively. Additional details for select
11 routine and small projects are provided in Exhibit A-20, Schedule J2 and are also
12 provided in the Part III (Questions 9 and 10) supplemental filing requirements.

13

14 The expenditures and project make-up are generally consistent each operating cycle
15 and peak during refueling outage periods because of the regulatory and safety
16 requirements governing Routine and Small Projects. I will highlight specific
17 Routine and Small Projects to help convey the type of projects that comprise Routine
18 and Small Projects in my testimony next.

19

20 **Q28. Prior to discussing the highlighted projects, can you please generally discuss**
21 **the capital expenditures for the historical year ending December 31, 2022, the**
22 **projected bridge years ending December 31, 2023 and December 31, 2024, and**
23 **the projected test year ending December 31, 2025?**

24 A28. Historical year ending December 31, 2022 included Refueling Outage 21 (RF21).
25 Most of the Small and Routine expenditures within the historical year ending

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1 December 31, 2022 were associated with projects (such as the Visual Annunciator
2 System replacement) that completed and went into service during RF21.

3
4 The projected bridge year ending December 31, 2023 is the year proceeding a
5 refueling outage (RF22 in spring 2024); many of the project expenditures (such as
6 control rod drive mechanism (CRDM) replacements) in 2023 are associated with
7 planning, readying and material procurement for RF22.

8
9 The projected bridge year ending December 31, 2024 is the year that includes RF22
10 and, as such, most of the Small and Routine expenditures are associated with
11 projects (such as the Residual Heat Removal Service Water (RHRSW) outlet valve
12 (F068A/B) replacement) projected to be completed and go into service during RF22.

13
14 The projected test period ending December 31, 2025 is again a year that proceeds a
15 refueling outage (RF23 in spring 2026), and similar to the projected bridge year
16 ending December 31, 2023, many project expenditures (such as control rod drive
17 mechanism (CRDM) replacements) in 2025 are associated with planning, readying
18 and material procurement for RF23.

19
20 **Q29. Does the general expenditure pattern just described apply to multi-year**
21 **projects such as the Security System Computer replacement project shown on**
22 **line 4, Plant Radio System project shown on line 5 on Exhibit A-12, Schedule**
23 **B5.3, page 2, and Plant Wireless project shown on line 35 on Exhibit A-12,**
24 **Schedule B5.3, page 3?**

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1 A29. No. Security System Computer, Plant Radio System and Plant Wireless projects are
2 examples of multi-year Routine and Small Projects with predominately online
3 implementation, so the general pattern of Routine and Small Projects expenditures
4 just discussed is not as relevant to these projects. Because these projects are multi-
5 year, I previously discussed these three projects in DTE Electric Rate Cases U-
6 20836 and U-21297; nonetheless, because of their continued importance to our
7 nuclear safety paradigm, I will again highlight these projects here.

8

9 **Q30. Can you discuss the expenditures and rationale for the Security System**
10 **Computer replacement project shown on Exhibit A-12, Schedule B5.3, page 2,**
11 **line 4?**

12 A30. The Security System Computer replacement project capital expenditures for the
13 historical test year, projected bridge forecast period and projected test period are
14 \$7.1 million, \$26.8 million and \$0.0 million respectively and projects to complete
15 prior to the end of the projected test period. This project addresses aging and
16 obsolescence of the existing security system computer, and support the necessary
17 replacement of the Fermi 2 Security System Computer which includes specialized
18 computer servers, video cameras, other access control and detection devices, and
19 communication cabling. This major plant security system is an aspect of the
20 regulatory-required Fermi 2 Security Protection Plan per Code of Federal
21 Regulation 10 CFR 73.55 which requires a physical security plan that must “ensure
22 that the capabilities to detect, assess, interdict, and neutralize threats up to and
23 including the design basis threat of radiological sabotage as stated in 10 CFR 73.1,
24 are maintained at all times” and “provide defense-in-depth through the integration
25 of systems, technologies, programs, equipment, supporting processes, and

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1 implementing procedures as needed to ensure the effectiveness of the physical
2 protection program.”

3

4 **Q31. Why is replacement of the security system computer necessary within the**
5 **projected test period?**

6 A31. Components of the existing security system computer have exhibited decreased
7 performance as service time has increased. Degradation of security equipment
8 results in multiple alarms that distract the security force from core activities, requires
9 compensatory measures which require unscheduled overtime, requires emergent
10 maintenance, and increases the risk of gaps in meeting the regulatory
11 requirements. In 2022, one of the intrusion detection systems accumulated three
12 times more annual out of service time than it did in 2021, indicating a need to replace
13 the system. Repair and replacement of existing components has become
14 increasingly difficult as equipment becomes obsolete; for example, vendor
15 supported software updates ceased for the security system computer’s video
16 monitoring software, video server operating system, and the server and workstation
17 operating system in 2015, 2016 and 2020 respectively. Lack of vendor support for
18 these operating systems or video monitoring systems could lead to extended loss of
19 security video feeds which would require additional security personnel to
20 compensate for the loss of video surveillance.

21

22 A security computer system used in the security of a nuclear power plant can be
23 reasonably expected to be in service for approximately 10 – 15 years based on
24 anticipated aging and obsolescence factors. Aspects of the Fermi 2 security system
25 computer such as the communications cabling have been in service for more than

Line
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1 thirty years; while the security system computer servers, workstations and access
2 controls hardware is comparatively newer – this hardware still relies on late-2000s
3 vintage technology. NRC cyber security regulations and the deeply integrated nature
4 of the security system computer makes replacement components increasingly
5 impractical to procure.

6
7 Preemptive replacement of the security system computer and its constituent
8 components is a reasonable and prudent action, consistent with our nuclear safety
9 priorities to support DTE Electric continuing to meet its regulatory commitments
10 into the 2030s when DTE Electric anticipates the next routine replacement of the
11 security system computer to occur. Several portions of this project also bring
12 equipment and strategy up to nuclear industry standards. Additionally, these
13 replacements will allow for more efficient equipment maintenance.

14
15 The integrated project also includes addition of equipment, for example, additional
16 cameras, and changes to the location of some equipment to support satisfactory
17 outcomes from NRC-graded Force-on-Force exercises as well as a formal
18 assessment of the Security Strategy.

19

20 **Q32. What is the role of the security computer system within the nuclear safety**
21 **paradigm you discussed earlier in your testimony?**

22 A32. The security computer system itself is an aspect of the Fermi 2 Physical Security
23 Plan (the exact details of physical security plans are safeguarded and protected per
24 regulation) – having and maintaining Fermi 2’s security equipment in accordance
25 with the approved physical security plan is a regulatory requirement and a condition

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1 to maintaining the Fermi 2 operating license. Because the consequences of hostile
2 actors acting against a U.S. commercial nuclear plant are significant, each U.S.
3 commercial nuclear site's physical security plan is routinely inspected and tested by
4 the NRC to ensure compliance. DTE Electric has an obligation to ensure that all
5 aspects of the Fermi 2 physical security plan work and will continue to work in the
6 future – hence a preemptive replacement regimen is necessary to ensure components
7 of the security computer system do not unexpectedly or unrecoverably fail.

8

9 As DTE Electric replaces the existing security computer system, Fermi 2 must
10 remain in compliance with regulations such that: (1) the functions and capabilities
11 of the existing security computer system must be maintained while the new system
12 is being installed, (2) design, configuration control and work to replace the existing
13 security computer systems must be performed so as to maintain operability of other
14 Fermi 2 plant systems including taking special care when excavating to replace
15 cabling and other components, (3) the new security computer system must meet
16 NRC cyber security requirements, (4) the new system must be designed and tested
17 for continuous operations with minimal maintenance time. Total project
18 expenditures are commensurate with these regulatory requirements.

19

20 **Q33. Was the Security System Computer project competitively sourced?**

21 A33. Yes. Consistent with the commercial principles I discussed earlier, the Security
22 System Computer project uses competitively-sourced suppliers. While commercial
23 processes and agreements are sensitive information, DTE Electric provides relevant
24 sourcing documents, subject to non-disclosure orders, within the natural order of

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1 this proceeding; other supplier and project information can be found in this
2 proceeding's Part III, Attachment 9 supplement filing.

3

4 Total project costs reasonably and prudently reflect actual and projected costs based
5 on the commercial solicitations and agreements. As I discussed earlier, commercial
6 solicitation processes such as competitive sourcing is a principle of prioritizing
7 nuclear safety to support safe, reliable and efficient project execution and post-
8 implementation equipment operations.

9

10 **Q34. Can you discuss the expenditures and rationale for the Plant Radio System**
11 **replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 5?**

12 A34. The Plant Radio System capital expenditures for the historical test year, projected
13 bridge forecast period and the projected test period are \$4.2 million, \$7.5 million
14 and \$0.0 million respectively, do not extend beyond the projected test period,
15 address security and operations vulnerabilities of the existing plant radio system,
16 and support the necessary replacement of the Fermi 2 plant radio system which
17 includes computers, radio repeaters, radio antenna, uninterruptible power supplies
18 and communications cabling. This major system is an aspect of the regulatory-
19 required Fermi 2 Physical Security Plan and the regulatory-required Fermi 2
20 Radiological Emergency Response Plan and has the purpose to be the primary
21 means of communication for plant personnel including site security and fire brigade
22 during operations and potential accident scenarios; loss of the plant radio system
23 would degrade plant operators' ability to safely operate the Fermi 2 Power Plant.

24

Line
No.

1 **Q35. Why is replacement of the plant radio system necessary within the projected**
2 **test period?**

3 A35. Security and operations vulnerabilities. Replacement of the plant radio system began
4 in 2017 with the replacement of plant radio equipment in the Fermi 2 Main Control
5 Room (MCR); field radio communications to the MCR were becoming increasingly
6 inaudible within the MCR which was unduly burdening plant operators during plant
7 operations. Additionally, radio communications within the power plant uses an
8 antenna system installed in the early 1980s, experiences a significant signal loss
9 between the base station and the distributed antennas and is capable of transmitting
10 only the UHS frequency band. Replacement of the plant radio system distributed
11 antenna system, communications cabling and uninterruptible power supplies (which
12 is the scope of work during the bridge and projected test periods in this case) will
13 improve plant radio signal fidelity throughout the plant and add two additional radio
14 frequencies bands (VHS and 800 MHZ) within the power plant.

15

16 Improving plant radio signal fidelity within the plant supports improved operations
17 communications, especially for emergency responders such as fire brigade in all
18 areas of the plant.

19

20 Adding the two additional radio frequency bands also allows DTE Electric to
21 evaluate changes to the Fermi 2 Physical Security Plan, further improve Fermi 2's
22 security posture and enhance security's communication capabilities with outside
23 emergency responders such as the Michigan State Police.

24

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No.

1 **Q36. What is the role of the plant radio system within the nuclear safety paradigm**
2 **you discussed earlier in your testimony?**

3 A36. The plant radio system is an aspect of the Fermi 2 Radiological Emergency
4 Response Plan – having and maintaining Fermi 2’s plant radio equipment in
5 accordance with the approved emergency response plan is a regulatory requirement
6 and a condition to maintaining the Fermi 2 operating license. Because the
7 consequences of an ineffective radiological emergency response are significant,
8 each U.S. commercial nuclear site’s emergency response plan is routinely inspected
9 and tested by the NRC and the Federal Emergency Management Agency (FEMA)
10 to ensure compliance. DTE Electric has an obligation to ensure that the components
11 of the Fermi 2 Radiological Emergency Response Plan work and will continue to
12 work in the future – hence a preemptive replacement regimen is reasonable and
13 prudent.

14

15 The plant radio system is the primary communication means for plant operators and
16 security officers responding to emergency conditions – unexpected or unrestorable
17 failure or interruption of this equipment would be an unacceptable risk to first
18 responders to any Fermi 2 plant emergency; it is imperative that the plant radio
19 system maintains its capabilities throughout the plant and through all postulated
20 operating scenarios.

21

22 As Fermi 2 replaces the existing plant radio system, the Company must remain in
23 compliance with regulations such that: (1) the functions and capabilities of the
24 existing plant radio system must be maintained while the new system is being
25 installed, (2) design, configuration control and work to replace the existing plant

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1 radio system must be performed as to maintain operability of other Fermi 2 plant
2 systems, (3) the new plant radio system must meet NRC cyber security
3 requirements, and (4) the new system must be designed and tested for continuous
4 operations with minimal maintenance time. This requires installing 16 new antennae
5 and approximately 5800 feet of new conduit and cable. Total project expenditures
6 are commensurate with these regulatory requirements.

7

8 **Q37. Can you discuss the expenditures and rationale for the Plant Wireless project**
9 **shown on Exhibit A-12, Schedule B5.3, page 3, line 35?**

10 A37. The Plant Wireless project capital expenditures for the historical test year, projected
11 bridge forecast period and the projected test period are \$0.3 million, \$7.7 million
12 and \$0.0 million respectively, do not extend beyond the projected test period,
13 address operational vulnerabilities and support the replacement and expansion of the
14 existing Fermi 2 plant wireless system which includes modems, network switches,
15 and wireless antennae. The purpose of the plant wireless system is to provide
16 wireless data communications capacity to plant personnel during normal operations;
17 not replacing and expanding the plant wireless system would challenge operations
18 to effectively operate the plant. In addition, the Plant Wireless project is resource-
19 optimized with the Plant Radio System replacement project by sharing the conduit
20 and cable trays.

21

22 **Q38. What is the role of the plant wireless system within the nuclear safety paradigm**
23 **you discussed earlier in your testimony?**

24 A38. Installation of a wireless communication backbone throughout the nuclear power
25 block directly impacts the ability to progress with other cost-savings and

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1 radiological dose-savings initiatives including Electronic Work Orders, Electronic
2 Operator Rounds, remote dose monitoring and remote equipment monitoring. NRC
3 regulations require management measures which include configuration
4 management, maintenance, training and certification, procedures, records
5 management, and other quality assurance methods, generally on a continuing basis,
6 that are applied to items relied on for safety, to ensure the items are available and
7 reliable to perform their functions when needed. Plant wireless system provides the
8 networking infrastructure and capacity necessary for Fermi 2 to modernize and
9 maintain these management measures. Plant wireless networks are used in the
10 nuclear industry to provide efficiency in recording and automatically storing
11 regulatory-required documentation and for additional monitoring of equipment
12 important to nuclear safety and plant reliability without incurring the large costs of
13 permanent imbedded cabling.

14

15 Existing management measures require controlled paper copies of work orders,
16 plant drawings, engineering design documents, purchasing agreements, time sheets
17 and procedures in the field – not that different from when the Fermi 2 first started
18 commercial operations in 1988. While these paper-document management measures
19 continue to support safe and reliable operations, modern industry-best practices have
20 evolved to use paperless work orders and procedures, automated document control
21 and records management, and electronic time keeping systems to reduce human
22 error precursors and to maintain positive configuration control of the plant.

23

24 As DTE Electric replaces and expands the existing plant wireless system, the
25 Company must remain in compliance with regulations such that: (1) design,

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1 configuration control and work to replace and expand the existing plant wireless
2 system must be performed so as to maintain operability of other Fermi 2 plant
3 systems, (2) wireless network signals from the plant wireless system must strike a
4 difficult engineering balance between strong signal strength and bandwidth against
5 requirements that the signals not interfere with the function of other plant equipment
6 and (3) the new plant wireless system must meet NRC cyber security requirements.
7 Total project expenditures are commensurate with these regulatory requirements.

8

9 **Q39. What do you mean by “aging and obsolescence?”**

10 A39. Aging in the context of nuclear plant operations refers to the general process in
11 which characteristics of equipment or components gradually degrade with time or
12 use.

13

14 Component obsolescence in the context of nuclear plant operations refers to
15 equipment or components that are no longer manufactured or qualified by their
16 original manufacturers.

17

18 **Q40. Why is obsolescence a particular concern for DTE Electric at the Fermi 2**
19 **Power Plant?**

20 A40. I have discussed aging and obsolescence a few times already because aging and
21 obsolescence concerns are not just a focus for DTE Electric, but a focus for the entire
22 U.S. nuclear industry. Configuration management at a nuclear power plant specifies
23 allowed components by manufacturer and model number. Once manufacturers cease
24 operations, change ownership or cease production of a particular model, nuclear
25 operators must identify potential replacements. This process of identifying potential

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1 replacements is rigorous as all aspects of the potential replacement's fit, form and
2 function must be evaluated by qualified engineers. Potential replacements may also
3 require physical modification to the plant to be usable – Security System Computer
4 is one such project that requires modifications to the Fermi 2 plant to address aging
5 and obsolescence.

6
7 Unexpected or unrecoverable failures of obsolete components are a vulnerability to
8 safe and reliable plant operations. Of course, as components age, the vulnerability
9 of unrecoverable failure increases. Unexpected or unrecoverable failures of obsolete
10 components could result in the extended compensatory measures that burden
11 operations, security, or other plant personnel; shutdown of the plant is also a
12 possibility until potential replacements are identified and actions are taken to make
13 the replacement usable within the plant.

14

15 **Q41. What actions must a nuclear operator such as DTE Electric take to physically**
16 **modify the plant?**

17 A41. When new or replacement components or equipment require a plant modification,
18 in addition to the physical field work of the modification there are several
19 management actions required: (1) plant drawings and component databases must be
20 updated, (2) plant calculations must be revised to ensure sufficient structural loading
21 or electrical loading margins exist, (3) physical security and emergency response
22 plans must be evaluated and possibly revised, (4) operating license and safety
23 analysis reporting must be evaluated and possibly revised, and (5) training,
24 operations and maintenance programs must be evaluated and possibly revised.

25

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1 The resources, time, and costs of these regulatory-required management measures
2 are non-trivial.

3

4 **Q42. Can you discuss the expenditures and rationale for the Undervessel**
5 **Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 2?**

6 A42. I previously discussed the routine Undervessel Replacements project, as well as the
7 related projects involving Control Rod Blade Replacements and Control Rod Drive
8 Mechanisms Replacements, in Case No. U-21297. DTE Electric has depicted the
9 ongoing and updated capital expenditures for these projects in each DTE Electric
10 rate case dating back to at least U-16472 without contention. I would like to again
11 establish the importance of these Routine and Small Projects with a discussion here,
12 starting with the Undervessel Replacements project. The Undervessel Replacements
13 capital expenditures for the historical test year, projected bridge forecast period and
14 projected test period are \$8.0 million, \$6.6 million, and \$0.0 million respectively.
15 These expenditures do extend beyond the projected test period and through the
16 balance-of-life of the Fermi 2 Power Plant, address component aging, and support
17 the necessary replacement of undervessel components which include control rod
18 drives and nuclear instrumentation such as local power range monitors (LPRMs).
19 The purpose of undervessel components goes to the heart of safely operating a
20 nuclear reactor and directly affects control and monitoring of power levels
21 throughout the reactor core (undervessel components are so named because the
22 components are driven by equipment located underneath the reactor pressure
23 vessel); unplanned or unrecoverable loss of these components would challenge plant
24 operator's ability to safely operate the Fermi 2 plant.

25

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1 **Q43. Can you discuss the expenditures and rationale for the Control Rod Blade**
2 **Replacements project shown on Exhibit A-12, Schedule B5.3, page 3, line 45?**

3 A43. The Control Rod Blade (CRB) Replacement project capital expenditures for the
4 historical test year, projected bridge forecast period and projected test period are
5 \$0.1 million, \$1.0 million, and \$0.9 million respectively, do extend beyond the
6 projected test period and through the balance-of-life of the Fermi 2 Power Plant,
7 closely relates to the Undervessel Replacements projects, address CRB component
8 aging, and support the necessary replacement of the CRBs (DTE Electric replaced
9 19 CRBs in RF21 and projects replacement of 22 CRBs in RF22). The purpose of
10 Fermi 2's 185 CRBs is to control power levels within the reactor core and to
11 ultimately safely accomplish shut down of the reactor when appropriate; unplanned
12 or unrecoverable loss of the CRBs would challenge plant operator's ability to safely
13 operate the Fermi 2 plant.

14

15 **Q44. Can you discuss the expenditures and rationale for the Control Rod Drive**
16 **Mechanisms project shown on Exhibit A-12, Schedule B5.3, page 2, line 28?**

17 A44. The Control Rod Drive Mechanism (CRDM) replacement project capital
18 expenditures for the historical test year, projected bridge forecast period and
19 projected test period are \$0.9 million, \$5.2 million, and \$4.9 million respectively,
20 do extend beyond the projected test period and through the balance-of-life of the
21 Fermi 2 Power Plant, closely relates to the Undervessel Replacements projects,
22 address CRDM component aging, and support the necessary replacement of the
23 CRDMs (DTE Electric replaced 20 CRDMs in RF21 and projects replacement of
24 20 CRDMs in RF22 and 20 CRDMs in RF23 (spring 2026)). The purpose of Fermi
25 2's 185 CRDMs is to control power levels within the reactor core and to ultimately

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1 safely accomplish shut down of the reactor upon receiving either manual or
2 automatic signals; unplanned or unrecoverable loss of the CRDMs would challenge
3 plant operator's ability to safely operate the Fermi 2 plant.

4

5 **Q45. Why is Fermi projecting to replace 22 CRBs in RF22 and only 20 CDRMs in**
6 **RF22?**

7 A45. Although CRBs and CRDMs are part of the same control rod drive system, the aging
8 mechanism is very different between CRDMs and CRBs. CRDMs (hydraulic piston
9 assemblies located underneath the reactor pressure vessel) are subject to harsh
10 environmental conditions such as extreme heat, moisture and radiation; after time,
11 the components of the CRDM will naturally stress, fatigue and wear and must be
12 replaced. CRBs (crucible-shaped, metal-tube components that contain a neutron-
13 absorbing material located inside the reactor core adjacent to fuel assemblies) are
14 subject to the extreme environment of the reactor itself; after time, the neutron-
15 absorbing material is consumed preventing it from fully performing its function to
16 shutdown the reactor or the CRB structural material will stress, fatigue and wear and
17 may become damaged during operation which could directly impact fuel integrity.

18

19 Each component of the control rod drive system must be evaluated and replaced on
20 its own schedule. For CRBs, DTE Electric determines this schedule based on
21 analysis of the operational history of the individual CRBs, calculates remaining
22 useful core life, and performs confirmatory testing to ensure the CRBs perform as
23 expected. For CRDMs, DTE Electric levelizes the replacements of the CRDMs over
24 their approximately 12-cycle in-service life.

25

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1 **Q46. What is the status of the commercial agreements for the Undervessel**
2 **Replacements, CRBs and CRDMs?**

3 A46. DTE Electric has negotiated long-term commercial agreements (using the
4 commercial principles I discussed earlier) for the OEM suppliers to provide these
5 vital nuclear components and services through at least 2027. These long-term
6 agreements provide DTE Electric with high assurance of adequate supply of
7 nuclear-quality plant components at predictable quality, compatibility and cost –
8 which is certainly reasonable and prudent.

9

10 **Q47. What are the expenditures and rationale for the Roof Replacements project**
11 **shown on Exhibit A-12, Schedule B5.3, page 3, line 51?**

12 A47. The Roof Replacements project capital expenditures for the historical test year,
13 projected bridge forecast period and projected test period are \$0.0 million, \$3.3
14 million, and \$0.0 million respectively with complete replacements of the Office
15 Building Annex (OBA), Office Service Building (OSB), and Warehouse A roofs
16 already complete in 2023. Of course, DTE Electric projects other roofs to be
17 replaced in the future but those future project expenditures would occur beyond 12-
18 month projected test period ending December 31, 2025 and are not included in this
19 proceeding.

20

21 **Q48. Why was replacement of these roofs necessary in 2023?**

22 A48. Aging. The roofs in scope are original to the plant and leaked and further repair was
23 constrained by their antiquated design. The Fermi 2 OBA and OSB house nuclear
24 operations staff, work control, outage management staff and maintenance staff as
25 well as the Fermi 2 maintenance shops (Mechanical, Electrical and Instrument &

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1 Controls (I&C) and machine shop). Warehouse A is the warehouse within the Fermi
2 2 Protected Area used for staging parts and materials for upcoming work.

3

4 **Q49. What is the role of the Roof Replacements project within the nuclear safety**
5 **paradigm you discussed earlier in your testimony?**

6 A49. All workers – at a nuclear power plant or otherwise, should be able to work in an
7 environment safe from industrial hazards such as leaking roofs.

8

9 Our U.S. nuclear industry refers to workers at nuclear power plants as “nuclear
10 professionals.” Our industry places considerable expectations on nuclear
11 professionals and appropriately so given the obligation to safely operate nuclear
12 power plants. One of these expectations is that nuclear professionals are to practice
13 good housekeeping and control of work areas to minimize the potential for injuries,
14 likelihood of human error, the spread of contamination and the generation of nuclear
15 waste; tolerating leaking roofs, which have the potential to undermine any of the
16 aspects of the expectation I just outlined risks undermining a criterion of nuclear
17 professionalism – which would not be reasonable and would not be prudent.

18

19 **Non-Routine and Large Projects Capital Expenditures**

20 **Q50. Can you discuss the Non-Routine and Large Projects summarized on line 3 of**
21 **Exhibit A-12, Schedule B5.3, page 1?**

22 A50. Non-Routine and Large Projects are projects that are necessary to properly maintain
23 the Fermi 2 asset and are incremental to normal routine capital expenditures.

24

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1 Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that
2 support page 1, line 3.

3

4 **Q51. Can you explain the Non-Routine and Large Projects detailed in Exhibit A-12,**
5 **Schedule B5.3, page 4?**

6 A51. Yes. This exhibit shows the by-project capital expenditures for Non-Routine and
7 Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These
8 projects for the historical test year, the projected expenditures for the 24-month
9 bridge forecast period ending December 31, 2024 and the 12-month projected test
10 period ending December 31, 2025 total \$173.2 million, \$204.3 million and \$38.4
11 million respectively. A discussion of certain Non-Routine and Large Projects
12 follows with additional details for other Non-Routine and Large Projects provided
13 in the Part III (Questions 9 and 10) supplemental filing documents.

14

15 **Q52. Can you explain the expenditures and rationale for the Main Unit Generator**
16 **projects shown on line 2 and line 5 of Exhibit A-12, Schedule B5.3, page 4?**

17 A52. The main unit generator projects are a series of replacements necessary to address
18 both an Original Equipment Manufacturer (OEM) design vulnerability and improve
19 overall reliability through 2045. These projects also support electrical grid
20 reliability. Replacement of this model of generator is the identical approach other
21 nuclear generation owners have taken over the years to mitigate operational risk. To
22 support reliable operation of Fermi 2 through 2045, major refurbishments and
23 replacement of the existing generator asset is reasonable and prudent. The
24 replacement main unit generator stator, as of January 2024, is at the manufacturing
25 facility in New York. Work is ongoing to ready the replacement main unit generator

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1 stator. DTE Electric will continue to make reasonable and prudent decisions to
2 ensure the main unit generator project, once complete, will support safe and reliable
3 operations through Fermi 2's operating license termination date in 2045.

4
5 The Main Unit Generator rotor replacement project as depicted on line 5 replaced
6 the existing main unit generator rotor with a refurbished spare rotor during RF21.
7 This replacement was performed to mitigate operational vulnerabilities associated
8 with the existing main unit generator. This replacement occurred during RF21 and
9 has capital expenditures for the historical test year, projected bridge forecast period,
10 and projected test period of \$15.9 million, \$0.0 million and \$0.0 million
11 respectively.

12
13 The Main Unit Generator Replacement project as depicted on line 2 is to replace the
14 generator stator and rotor with a matched stator and rotor. This replacement is
15 projected to occur during RF23 (Spring 2026) and has capital expenditures for the
16 historical test year, projected bridge forecast period and projected test period of
17 \$47.1 million, \$87.9 million and \$14.3 million respectively.

18

19 **Q53. Why was the Fermi 2 main unit generator rotor replaced in RF21?**

20 A53. The Midcontinent Independent System Operator (MISO) identified that Trenton
21 Channel Unit 9 would be designated as a System Support Resource (SSR) (and thus
22 would be required to continue to be operable and not eligible for retirement) unless
23 an alternative solution was identified to resolve violations of applicable reliability
24 criteria upon the unit's retirement. Replacement of the existing Fermi 2 main unit
25 generator rotor (and the generator excitation automatic voltage regulator (AVR)

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1 depicted on line 6 of Exhibit A-12, Schedule B5.3, page 4) was required in
2 conjunction with replacement of Service System Transformer #65 (depicted on line
3 7 of Exhibit A-12, Schedule B5.3, page 4) prior to retirement of the Trenton Channel
4 Power Plant in May of 2022 to resolve the reliability issues that would otherwise
5 occur. The Fermi 2 generator rotor and AVR that were in-service prior to RF21 were
6 not capable of generating sufficient reactive power to solve the reliability issues
7 identified by MISO. RF21 was the Company's last window of opportunity to replace
8 the Fermi 2 generator rotor to maintain the Trenton Channel Unit 9 planned 2022
9 retirement date as required by the 2020 Consent Decree between the Company and
10 the United States Environmental Protection Agency¹.

11

12 **Q54. What is the basis to replace the Fermi 2 main unit generator in RF23?**

13 A54. The existing Fermi 2 generator (stator) is the original plant equipment,
14 manufactured in the early 1970s using the technology of that time. The generator
15 stator is approaching end of life (EOL). To date, multiple known vulnerabilities and
16 degradation have been mitigated through increased maintenance bridging strategies;
17 however, design vulnerabilities associated with the stator continue to represent
18 increased risk for sudden failure. Unplanned or unexpected failures not only present
19 a generation risk but also present operational risk to the plant operators responsible
20 for maneuvering the plant to a shutdown condition following a generator failure.

21

22 A matched rotor will be installed in RF23 for two reasons: (1) a matched rotor can
23 be fit with the replacement stator prior to field work during RF23 which minimizes
24 project execution risk and (2) the current rotor installed in RF21 may be

¹ <https://www.justice.gov/enrd/consent-decree/file/1276421/download>, accessed January 6, 2024.

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1 contaminated with metallic particles after use with the original stator and its design
2 flaw which could jeopardize the integrity of the replacement stator if the current
3 rotor were to be reinstalled.

4
5 DTE Electric continues the necessary work to complete the replacement stator and
6 have the replacement main unit generator (stator and rotor) in a ready state.
7 Implementing the Main Unit Generator Replacement project in RF23 is a reasonable
8 and prudent action because of the current state described above. DTE Electric has
9 implemented and will continue to implement reasonable and prudent bridging
10 strategies to mitigate the short-term reliability risks associated with the existing
11 Fermi 2 main unit generator; however, given the main unit generator's importance
12 with respect to safe and reliable plant operations through 2045, DTE Electric has
13 scheduled implementation of the Main Unit Generator Replacement project in
14 RF23.

15

16 **Q55. What specific work is being performed at the manufacturer facility in New**
17 **York?**

18 A55. Subsequent inspections of the new generator stator revealed unsatisfactory foreign
19 material within the coatings applied to the stator. The generator stator has been
20 completely disassembled, and the coatings were removed. The stator parts were then
21 reinspected, recoated and reassembled.

22

23 **Q56. Why did the projected in-service date for the Main Unit Generator**
24 **Replacement project change from RF22 (2024) in U-21297 to RF23 (2026) in**
25 **this proceeding?**

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1 A56. Transportation from the manufacturing facility in New York to the Fermi 2 Power
2 Plant is performed via the St Lawrence Seaway. The Seaway and canals are
3 generally closed to shipping during the winter months. Rather than attempt to use
4 higher risk transportation methods or routes to support a delivery date that fully
5 supported sufficient time to ready the replacement generator for RF22 install, DTE
6 Electric made a well-reasoned and prudent decision to change the generator
7 replacement to RF23.

8

9 **Q57. Can you discuss the expenditures and rationale for the Underground Safety-**
10 **Related Service Water Piping project shown on line 4 of Exhibit A-12, Schedule**
11 **B5.3, page 4?**

12 A57. The Underground Safety-Related Service Water Piping capital expenditures for the
13 historical test year, projected bridge forecast period and projected test period are
14 \$23.3 million, \$42.9 million and \$0.0 million respectively. The Underground
15 Safety-Related Service Water Piping project replaces nuclear safety-related piping
16 that delivers cooling water to various components that support the operation of the
17 nuclear reactor. A portion of the underground safety-related service water piping
18 was replaced in RF21, with the remaining piping to be completed in RF22. The
19 replacement of the underground safety-related service water piping is necessary to
20 address age-related degrading pipe-wall thickness and to ensure this pipe will
21 continue to support plant operations through the end of the operating license in 2045.

22

23 **Q58. What does it mean to be “safety-related” piping?**

24 A58. In the U.S. nuclear industry, the term “safety-related” applies to systems, structures,
25 components, procedures, and controls that are relied upon to remain functional

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1 during and following design-basis events. Per NRC regulations, materials,
2 equipment and components of safety-related systems have very strict manufacturing
3 tolerances and quality control; new materials, equipment and components are
4 inspected against technically developed procurement specifications. Post-delivery
5 modifications to safety-related materials such as cutting, fitting and welding pipe
6 must be to design, properly controlled, traceable, and work inspected by qualified
7 inspectors. Work on safety-related equipment requires an exactness in performance
8 that is not common in non-nuclear industry.

9

10 **Q59. Can you discuss the expenditures and rationale for the General Service Water**
11 **(GSW) intake groin replacement shown on line 20 of Exhibit A-12, Schedule**
12 **B5.3, page 4?**

13 A59. The General Service Water (GSW) intake groin replacement project capital
14 expenditures for the historical test year, projected bridge forecast period and
15 projected test period are \$0.0 million, \$18.0 million, and \$0.0 million respectively,
16 do not extend beyond the projected test period, address natural erosion of the
17 existing GSW intake groin structure, and support the necessary replacement of the
18 GSW intake groin structure. The Fermi 2 GSW intake groin structure is comprised
19 of two armored-earthen jetties that jut into Lake Erie; the jetties' armor is rock and
20 concrete tetrapods which are designed to mitigate Lake Erie erosion action and yet
21 allow enough movement within the armor structure itself to mitigate Lake Erie ice
22 action from damaging the armor. The purpose of Fermi 2 GSW intake groin
23 structure is to protect the Fermi 2 GSW intakes from Lake Erie wave action,
24 minimize bio-material accumulation at the GSW intake and to minimize sediment
25 accumulation at the GSW intake; the Fermi 2 GSW system itself provides cooling

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1 water to plant equipment; unplanned or unrecoverable loss of the GSW would
2 challenge the plant operator's ability to safely operate the Fermi 2 plant.

3

4 **Q60. Can you discuss the expenditures and rationale for the License Renewal**
5 **Implementation (LRI) project shown on line 8 of Exhibit A-12, Schedule B5.3,**
6 **page 4?**

7 A60. The License Renewal Implementation (LRI) project capital expenditures for the
8 historical test year, projected bridge forecast period and projected test period are
9 \$5.8 million, \$15.3 million, and \$0.7 million respectively, do extend beyond the
10 projected test period, address DTE Electric's NRC renewed operating license
11 commitment, and support the necessary first-time and only-time inspection required
12 from Fermi 2 to operate during its Period of Extended Operations which begins in
13 2025. To ensure safe operations during a plant's Period of Extended Operation, the
14 NRC mandates programs to monitor and intrusively inspect passive plant systems
15 that may be impacted by plant age; the Fermi 2 LRI project coordinates and conducts
16 the first-time and one-time inspections associated with this new and regulatorily-
17 required monitoring and inspection regime; failure to complete these first-time and
18 one-time inspections would result in NRC violations and possible suspension of
19 Fermi 2's renewed operating license.

20

21 **Q61. Can you discuss the expenditures and rationale for the Circulating Water (CW)**
22 **Discharge Pipe project shown on line 9 of Exhibit A-12, Schedule B5.3, page 4?**

23 A61. The Circulating Water (CW) Discharge Pipe project capital expenditures for the
24 historical test year, projected bridge forecast period and projected test period are
25 \$5.3 million, \$0.0 million, and \$0.7 million respectively, extend beyond the

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1 projected test period, address natural aging of the Fermi 2 CW discharge piping, and
2 support the necessary in situ replacement of the CW discharge piping pressure
3 boundary with a carbon-fiber shell that lines the interior surface of the CW discharge
4 pipe. The Fermi 2 CW piping is two interconnected sets of underground 144”
5 diameter, pre-stressed concrete cylinder pipe (PCCP); total pipe length is
6 approximately a mile and comprised of approximately 450 pipe segments. The
7 purpose of Fermi 2 CW piping is to transport circulating water from the CW pond
8 to the Main Unit Condenser (CW inlet piping) and to transport the circulating water
9 from the Main Unit Condenser to the Fermi 2 natural draft cooling towers (CW
10 discharge piping); the Fermi 2 CW system itself provides cooling water to Main
11 Unit Condenser; unplanned or unrecoverable loss of the CW piping would challenge
12 plant operator’s ability to safely operate the Fermi 2 plant and cause a unit shutdown.

13

14 **Q62. Why is it necessary to replace the pressure boundary of the CW discharge**
15 **piping?**

16 A62. The CW pipe is original to plant construction and is aging – as all underground
17 concrete pipes do. The PCCP has a concrete core, a thin steel cylinder, high tensile
18 prestressing wires and a mortar coating. As PCCP ages the mortar will delaminate
19 exposing the prestressing wires to corrosion forces; as the prestressing wires
20 corrode, the strength of the PCCP deteriorates and the PCCP will catastrophically
21 fail.

22

23 Because the failure mode of PCCP is catastrophic failure, the reaction time of plant
24 operators to safely maneuver the plant is greatly reduced. DTE Electric is taking the
25 reasonable and prudent approach to perform in situ replacement of the interior CW

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1 pipe pressure boundary with a carbon-fiber liner, pipe segment by pipe segment,
2 over time and in stages based on priorities derived from inspections to minimize
3 refueling outage time.

4

5 **Q63. Can you discuss the expenditures and rationale for the Feed Water Heaters**
6 **Replacements project shown on line 10 of Exhibit A-12, Schedule B5.3, page 4?**

7 A63. The Feed Water Heaters Replacements capital expenditures for the historical test
8 year, projected bridge forecast period and projected test period are \$4.9 million,
9 \$11.1 million and \$4.7 million respectively. The Feed Water Heaters Replacements
10 project replaces six of Fermi 2's twelve feed water heaters that condition the nuclear
11 feed water for return to the reactor core. The six feed water heaters will be replaced
12 during RF23 (spring 2026) and RF24 (spring 2028); the remaining six feed water
13 heaters experience less operational stress and do not require replacement at this time.
14 The replacement of these feed water heaters, which are original plant equipment, is
15 necessary to address normal end-of-life degradation and improve operational
16 margins. Additionally, internal degradation of the existing feed water heaters
17 contributes to radiological dose rates in the plant. The new feed water heaters are
18 being constructed from materials that, as they wear and degrade during operation,
19 will not contribute radiological dose.

20

21 **Q64. Are there logistical complexities associated with the replacement of the feed**
22 **water heaters?**

23 A64. These feed water heaters are quite large (i.e. approximately the size of a semi-trailer
24 and weighing between 80,000 and 130,000 pounds each) and located in enclosed
25 rooms within Fermi 2 Turbine Building, surrounded by pipes. To get these feed

Line
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1 water heaters into the Turbine Building requires disassembly of the east wall of the
2 Turbine Building and relocation of structures within the building. Additionally, each
3 of the piping interferences must be removed from the feed water heater rooms to
4 allow the existing feed water heaters enough space to be removed and new feed
5 water heaters moved into place; the interference piping must then be restored along
6 with the Turbine Building wall prior to unit startup.

7

8 **Q65. Can you discuss the expenditures and rationale for the drywell cooler projects**
9 **shown on lines 11, 16 and 18 of Exhibit A-12, Schedule B5.3, page 4?**

10 A65. These drywell cooler projects are part of a staged, multi-year effort to proactively
11 and systematically address a series of necessary drywell cooler replacements in a
12 manageable fashion based on risk of potential leakage. The replacements have been
13 grouped by refueling outage implementation. The replacement of these coolers is
14 necessary to address the normal end of life status and degradation of these coolers
15 which are original plant equipment. Excessive leakage from drywell coolers can
16 and have resulted in plant shutdowns to repair. Fermi 2 has 14 drywell coolers which
17 provide the containment structure that surrounds the reactor with atmospheric
18 cooling during normal operations.

19

20 Drywell Coolers #10 and #14, as depicted on line 18, were replaced in RF20 in the
21 spring of 2020 and have capital expenditures for the historical test year, projected
22 bridge forecast period and projected test period of \$0.0 million, \$0.0 million and
23 \$0.0 million respectively.

24

Line
No.

1 Drywell Coolers #12 and #13, as depicted on line 11, were replaced in RF21 and
2 have capital expenditures for the historical test year, projected bridge forecast period
3 and projected test period of \$3.5 million, \$0.0 million and \$0.0 million respectively.
4

5 Drywell Cooler #8 is depicted on line 16, is forecasted to be replaced in RF23 and
6 has capital expenditures for the historical test year, projected bridge forecast period
7 and projected test period of \$1.5 million, \$0.0 million and \$0.6 million respectively.
8

9 **Q66. Are there additional complexities associated with the replacement of the**
10 **drywell coolers?**

11 A66. The drywell coolers are located in the Fermi 2 drywell. The drywell immediately
12 surrounds the reactor pressure vessel and its environment is typically characterized
13 by high temperatures, radiologically contaminated surfaces and significant
14 radiological dose presence with densely configured plant equipment; while sealed
15 from entry during normal plant operations due to an inert nitrogen atmosphere, the
16 drywell does have two equipment hatches and a personnel hatch to allow equipment
17 and workers into the drywell during refueling outages. The travel paths for the
18 drywell coolers can be complex with many interferences that must be navigated
19 using potentially complex lifting and rigging evolutions or removed and later
20 reinstalled to successfully replace the coolers. Work must be highly scripted by
21 qualified individuals to address plant configuration challenges, minimize
22 radiological dose, and minimize human performance errors.
23

24 **Q67. Can you discuss the expenditures and rationale for the Boraflex Fuel Storage**
25 **Racks project shown on line 12 of Exhibit A-12, Schedule B5.3, page 4?**

Line
No.

1 A67. The Boraflex Fuel Storage Racks capital expenditures for the historical test year,
2 projected bridge forecast period and projected test period are \$3.4 million, \$4.0
3 million and \$0.0 million respectively. The Boraflex fuel storage racks project will
4 replace the end-of-life Boraflex fuel storage racks with new neutron-absorbing
5 material. The replacement of the Boraflex fuel storage racks is an NRC commitment
6 tied to Fermi 2's license renewal and is necessary to restore safety margins for the
7 storage of the spent fuel through the end of the operating license in 2045.

8

9 **Q68. Can you discuss the expenditures and rationale for the Radiation Monitors**
10 **project shown on line 13 of Exhibit A-12, Schedule B5.3, page 4?**

11 A68. The radiation monitors capital expenditures for the historical test year, projected
12 bridge forecast period and projected test period are \$2.7 million, \$13.2 million and
13 \$2.6 million respectively. The Radiation Monitors project replaces Fermi 2's
14 radiation monitor computer referred to as "SS1," as well as the plant's SPING
15 (detects particulate, iodine and noble gases) and AXM (accident range effluent
16 monitor) radiation monitors; together this radiation monitor system monitors and
17 analyzes the plant's gaseous effluents to affirm the plant's radiation levels remain
18 within proper specification. This radiation monitor system is credited in Fermi 2's
19 Emergency Response Plan due to its capacity to monitor and analyze potential
20 radioactive releases thus directly impacts recommendations provided to the state for
21 instituting emergency actions for the public in the event of an emergency. The
22 radiation monitor system will be replaced in phases throughout the bridge and test
23 period and is expected to be completed in 2025. The replacement of this radiation
24 monitor system is necessary to address aging and obsolescence, reduce the resource
25 and dose impact of compensatory sampling, and improve regulatory margins;

Line
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1 unexpected or unrecoverable loss of this radiation monitor system could result in
2 NRC enforcement action.

3

4 **Q69. Can you discuss the expenditures and rationale for the Fire Header Restoration**
5 **project shown on line 17 of Exhibit A-12, Schedule B5.3, page 4?**

6 A69. The Fire Header Restoration project capital expenditures for the historical test year,
7 projected bridge forecast period and projected test period are \$0.8 million, \$4.0
8 million, and \$0.0 million respectively, extend beyond the projected test period,
9 address natural aging of the Fermi 2 fire header piping, and support the necessary
10 replacement of the Fermi 2 fire header piping. The Fermi 2 fire header piping is
11 approximately 5000' of underground "ring header" comprised of 12" unlined,
12 ductile iron pipe that routes around the Fermi 2 Power Plant and a separate 6" header
13 for the station blackout diesels. The purpose of Fermi 2 fire header is to distribute
14 firefighting water from the normal or alternate sources of water to the scene of a
15 postulated fire; with fire being one of the most consequential events at a nuclear
16 power plant, unplanned or unrecoverable loss of the fire header piping would
17 challenge plant operator's ability to safely operate the Fermi 2 plant.

18

19 **Q70. Why is it necessary to replace the Fermi 2 fire header?**

20 A70. Normal aging. The fire header pipe is original to plant construction and is
21 approaching fifty years of in-service time. As a fire header, the piping is exposed to
22 raw lake water which degrades the interior surfaces of the pipe, causing leaks and
23 loss of water pressure. The existing fire header pipe would not support safe and
24 reliable operations through Fermi 2's current operating life ending in 2045. DTE
25 Electric is taking the reasonable and prudent approach to replace the fire header pipe

Line
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1 over time and in stages based on priorities derived from inspection and testing; this
2 also allows for minimal fire header outage time and minimal operational
3 compensatory measures to protect the plant while replacement is occurring.

4

5 **Q71. Can you discuss the expenditures and rationale for the Fire Detection System**
6 **Replacement project shown on line 24 of Exhibit A-12, Schedule B5.3, page 4?**

7 A71. The Fire Detection System Replacement project capital expenditures for the
8 historical test year, projected bridge forecast period and projected test period are
9 \$0.0 million, \$2.3 million, and \$1.3 million respectively, extend beyond the
10 projected test period, address obsolescence of the Fermi 2 fire detection system, and
11 support the necessary replacement of the Fermi 2 fire detection system. The Fermi
12 2 fire detection system consists of detection and annunciation systems. The purpose
13 of the Fermi 2 fire detection system is to detect fire and signal fire alarms, and is
14 designed to supplement Fermi 2's other fire safeguards such as design, procedures
15 and behaviors; with fire being one of the most consequential events at a nuclear
16 power plant, unplanned or unrecoverable loss of the fire detection system would
17 challenge plant operator's ability to safely operate the Fermi 2 plant.

18

19 **Q72. Can you discuss the expenditures and rationale for the Reactor Recirculation**
20 **Motor-Generator (RRMG) Replacements project shown on line 26 of Exhibit**
21 **A-12, Schedule B5.3, page 4?**

22 A72. The Reactor Recirculation Motor-Generator (RRMG) replacement project capital
23 expenditures for the historical test year, projected bridge forecast period and
24 projected test period are \$0.0 million, \$0.0 million, and \$6.2 million respectively,
25 extend beyond the projected test period, address aging of the two Fermi 2 RRMG

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1 sets, and support the necessary replacement of the Fermi 2 RRMGs. The existing
2 Fermi 2 RRMGs consist of an RRMG motor, fluid coupler, oil system, generator
3 and scoop tube positioner. The purpose of the Fermi 2 RRMG sets is to provide
4 variable power to the Fermi Reactor Recirculation System (RRS) pump motors, one
5 RRMG set controls one RRS pump motor.

6

7 **Q73. Why is it necessary to replace the Fermi 2 RRMG sets?**

8 A73. Primarily aging. The RRMG motor rotors, in particular have been in service since
9 plant start up in the 1980s and have increasing risk of developing shorts as in-service
10 time extends past 30 years. The Fermi 2 RRMG sets use complex mechanical
11 interactions to vary voltage to the RRS motors, and though this system had wide
12 spread usage when plants similar to Fermi 2 were built, the vast majority of US
13 Boiling Water Reactors (BWRs) have replaced the mechanical RRMG sets with
14 solid-state devices known as Variable Frequency Drives (VFDs), also known as
15 Adjustable Speed Drives (ASDs); these VFDs are mechanically simpler than
16 RRMGs, have developed a history of reliable operation, and use significantly less
17 house power to operate. DTE Electric is projecting to replace the Fermi 2 RRMG
18 sets in Refueling Outage 24 (Spring 2028).

19

20 **Q74. Can you discuss the expenditures and rationale for the Sanitary System**
21 **replacement project shown on line 28 of Exhibit A-12, Schedule B5.3, page 4?**

22 A74. The Sanitary System replacement project capital expenditures for the historical test
23 year, projected bridge forecast period and projected test period are \$0.0 million, \$0.0
24 million, and \$6.5 million respectively, extend beyond the projected test period,
25 address aging and undersized piping, and support the necessary replacement of the

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1 Fermi sanitary system. The sanitary wastewater system is designed to dispose of
2 nonradioactive plant sewage liquid waste in accordance with state and local
3 regulations and consists of piping and a pumping station. The current pump house,
4 which was originally built to support Fermi 1 operations, consists of a septic tank,
5 settling Tank, wet well, and pumps to transfer sewage around the facility and to
6 discharge out the forced main; however, the pumps are not designed to pump solid
7 waste and the concrete structure is in need of repair or replacement - due to the
8 location, a failure of the structure risks a release into Lake Erie. The sanitary system
9 project replaces this antiquated sanitary wastewater disposal with a more modern
10 two pump system capable of safely disposing of Fermi 2's sanitary wastewater.

11

12 **Q75. Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain**
13 **contingency amounts?**

14 A75. No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4
15 do not include contingencies. The capital expenditures shown in Exhibit A-12,
16 Schedule B5.3, pages 2-4 are good faith estimates (without contingencies) based on
17 relevant data available using reasonable and prudent forecasting methods.

18

19 **Q76. Does the absence of contingency amounts in Exhibit A-12, Schedule B5.3, pages**
20 **2-4 impact individual project expenditure variances from DTE Electric rate**
21 **case to rate case?**

22 A76. Certainly. The need for and use of contingency amounts at the individual project
23 level and at the portfolio level is well understood in project management and
24 portfolio management. Because DTE Electric's Nuclear Generation projects don't
25 include contingencies, some known scope with highly uncertain costs have

Line
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1 projected expenditures excluded from exhibits (such as the Security Computer
2 Replacement project) until such time the expenditures are capable of being
3 identified with reasonable specificity to include in the exhibit; therefore, projects
4 expenditures will necessarily change as less defined scope and previously excluded
5 expenditures transition into better identified and included expenditures. This is a
6 reasonable and prudent approach in light of the expectation to exclude contingency
7 amounts from DTE Electric's rate case exhibits and subsequent revenue
8 requirements.

9

10 **Q77. How does the Nuclear Generation organization manage its capital expenditures**
11 **without contingencies?**

12 A77. Nuclear Generation manages total capital expenditures for the period and expects
13 that capital expenditures in total will be incurred as projected. In general, Nuclear
14 Generation maintains a prioritized list of projects such that as project forecasts are
15 over or under expected amounts, Nuclear Generation uses this prioritized list
16 consistent with the key principles I described earlier to manage the Nuclear
17 Generation portfolio of projects.

18

19 **Nuclear Fuel Capital Expenditures**

20 **Q78. Can you explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12,**
21 **Schedule B5.3, page 1?**

22 A78. Yes. Total Nuclear Fuel includes those capital expenditures for the various
23 components of the nuclear fuel cycle: (1) Uranium, (2) Conversion, (3) Enrichment
24 and (4) Fabrication.

25

Line
No.

1 Uranium refers to the costs associated with mining and milling uranium. Natural
2 uranium is obtained from the exploration and mining of uranium ore. Milling is the
3 mechanical and chemical process of extracting uranium from the mined ore in the
4 form of U_3O_8 , commonly referred to as yellowcake. The U_3O_8 is the feed material
5 for the conversion process.

6

7 Conversion refers to the costs associated with chemically converting U_3O_8 into
8 UF_6 , uranium hexafluoride. The UF_6 is the gaseous compound used as a feed in the
9 enrichment process.

10

11 Enrichment refers to the costs to enrich the uranium from a natural 0.7% U^{235}
12 content to a 4% to 5% U^{235} content required for light water reactor fuel. The
13 enriched UF_6 is used as a feed in the fabrication process.

14

15 Fabrication refers to the chemical conversion of the enriched UF_6 to UO_2 (uranium
16 dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets
17 that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods
18 are then assembled into fuel bundles using spacers and end fittings to hold the fuel
19 rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to operate.

20

21 The amount of fuel purchased is determined by the design of the fuel and by the
22 expected generation during the life of the fuel. Nuclear fuel capital expenditures
23 were developed on the basis that Fermi 2 transitioned from its 18-month operating
24 cycle to the 24-month operating cycle following RF21 in winter/spring of 2022,
25 which occurred.

Line
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1 The accounting of nuclear fuel expenditures completes with the delivery of the
2 fabricated nuclear fuel to the Fermi 2 Power Plant. Expenditures arising from on-
3 site activities such as new fuel receipt, new fuel storage and insertion of the new
4 nuclear fuel into the reactor core are recorded in the appropriate expense account.
5

6 **Q79. Can you explain the Total Nuclear Fuel expenditures as shown on Exhibit A-**
7 **12, Schedule B5.3, page 1, line 10?**

8 A79. Yes. The Total Nuclear Fuel capital expenditures for the historical test year,
9 projected bridge forecast period and projected test period are \$3.3 million, \$112.0
10 million and \$135.1 million respectively and are consistent with Fermi 2's
11 projections in the Company's 2024 PSCR Plan in Case No. U-21425.
12

13 **Q80. Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?**

14 A80. Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2
15 operates on a 24-month fuel cycle and fuel expenditures occur at relatively fixed
16 points in time relative to that 24-month fuel cycle (most nuclear fuel capital
17 expenditures occur approximately six months prior to a refueling outage); therefore,
18 Total Nuclear Fuel capital expenditures can be expected to vary each year but follow
19 a repeating two-year pattern.
20

21 **Q81. How would you characterize the level of expenditures for Fermi 2's Total**
22 **Nuclear Fuel?**

23 A81. Fermi 2's fuel expenditures are reasonable and prudent. I expect fuel expenditures
24 to continue to be reasonable as the Company has secured the necessary uranium,

Line
No.

1 conversion, enrichment and fabrication through the projected test period ending
2 December 31, 2025.

3

4 **AFUDC Forecast**

5 **Q82. Can you explain the Allowance for Funds Used During Construction (AFUDC)**
6 **as shown in Exhibit A-12, Schedule B5.3, page 5?**

7 A82. Nuclear Generation capital expenditures include an Allowance for Funds Used
8 During Construction (AFUDC) for eligible projects that are in Construction Work
9 in Progress (CWIP); eligible projects are those projects greater than \$50,000 and
10 lasting more than six months. The actual historical period Total AFUDC – Nuclear
11 Production Plant was \$10.8 million as shown in Exhibit A-12, Schedule B5.3, page
12 5, line 33, column (b). The forecasted Total AFUDC – Nuclear Production Plant for
13 the projected test period is \$13.1 million as shown in Exhibit A-12, Schedule B5.3,
14 page 5, line 33, column (c).

15

16 **Q83. How did you forecast the AFUDC as shown in Exhibit A-12, Schedule B5.3,**
17 **page 5?**

18 A83. The Nuclear Production Plant – Routine Expenditures AFUDC forecast uses a
19 historical trend to estimate AFUDC as the mix of eligible projects is fairly consistent
20 year-to-year. The Nuclear Production Plant – Project Specific AFUDC forecast
21 explicitly calculates AFUDC for eligible projects using project-specific CWIP
22 balances multiplied by the AFUDC rate where the AFUDC rate is the authorized
23 cost of capital rate of 5.561% consistent with the December 1, 2023 Order in Case
24 No. U-21297.

25

Line
No.

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

2 **Q84. What is provided on the schedule entitled Removal Costs, Plant in Service and**
3 **CWIP schedule on Exhibit A-12, Schedule B5.3, page 6?**

4 A84. This schedule provides a breakdown of plant activities which are used by Witness
5 Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the
6 projected balance sheet.

7
8 Capital expenditures consistent with page 1 are summarized in columns (c) through
9 (f). Routine and Non-Routine projects are sub-totaled on Lines 1 and 31
10 respectively, while Fermi 2 License Renewal has been identified separately on line
11 33 because this is recorded to Plant Held for Future Use. Column (b) includes a
12 corresponding in-service assumption: "Annual" is indicated for both routine and
13 non-routine spend because these projects are generally unitized within the year of
14 spend.

15
16 Column (g) includes an estimated percentage of removal costs that are included
17 within the capital expenditures. Removal costs, as discussed by Witness Uzenski,
18 are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore
19 not depreciable. Removal cost of 15% based on historical trend of removals as a
20 component of capital expenditures is applied to Routine and Non-Routine project
21 expenditures.

22
23 Column (h) through (j) reflect calculated removal costs based on projected Capital
24 Expenditures in columns (d) through (f) multiplied by the removal cost percentage
25 in column (g). The remaining Capital Expenditures will appear in Plant in Service

Line
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1 columns (k) through (m) since the in-service assumption is “Annual.” The CWIP
2 columns (n) through (p) show CWIP activity.

3

4 **2022 – 2025 Capital Projects Summary**

5 **Q85. What is your opinion regarding the reasonableness of the forecasted capital**
6 **expenditures for Nuclear Generation?**

7 A85. I believe the forecasted capital expenditures for Nuclear Generation are reasonable
8 and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule
9 B5.3, page 1, accurately represents the capital expenditures that can reasonably be
10 expected to continue operation of nuclear assets of similar age and vintage. My
11 summation of projects reflects DTE Electric’s commitment to ensure the safe and
12 reliable operation of Fermi 2 through its current operating license expiration in 2045.
13 As I have expressed previously, these capital expenditures are prudent and
14 reasonable given the regulations, goals and conditions under which Fermi 2
15 operates.

16

17 **Nuclear Generation O&M Expense**

18 **Q86. Can you provide an outline of your Nuclear Generation O&M discussion?**

19 A86. Yes. My testimony will begin with the O&M Expenses Overview and then discuss
20 and support the additional details regarding:

- 21 • Rate Case Adjustments
- 22 • Adjusted Historical Test Period
- 23 • Projected Adjustments

24

Line
No.

1 **O&M Expenses Overview**

2 **Q87. Can you provide an overview of the Nuclear Generation O&M expenses**
3 **supported by your testimony?**

4 A87. Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M
5 expenses for the 12-month historical test period ended December 31, 2022,
6 adjustments to the historical test period, and then the forecasted O&M expenses for
7 the 12-month projected test period ending December 31, 2025.

8

9 The actual O&M expenses by FERC account for the 12-month historical test period
10 ended December 31, 2022 were \$220.3 million as shown in column (c). Rate case
11 adjustments are made in column (d) to reduce O&M by \$28.6 million to account for
12 the Nuclear Surcharge, in column (e) to reclassify Project Evaluation Review
13 Committee (PERC) nuclear O&M project expenditures, and zero other historical
14 adjustment in column (f). These rate case adjustments result in \$191.8 million of
15 adjusted O&M for the 2022 historical test period as shown in column (g).

16

17 Projected adjustments of \$5.1 million, \$4.8 million and \$4.9 million in columns (h),
18 (i) and (j) respectively account for inflation. The \$35.9 million decrease in column
19 (k) is subtracted to account for outage accrual adjustments and O&M is reduced by
20 \$11.4 million in column (l) to account for the total PERC expense in the forecasted
21 test period as supported by calculations performed by Company Witness Uzenski.
22 These projected adjustments yield a total change of \$32.4 million as shown in
23 column (m).

24

Line
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1 With the above adjustments, the forecasted O&M expenses for the 12-month
2 projected test period are \$159.4 million as shown in column (n).

3

4 **Q88. What projected Total Nuclear Power Generation O&M expenses are you**
5 **supporting?**

6 A88. I am supporting projected Total Nuclear Power Generation O&M expenses of
7 \$159.4 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (n) as
8 reasonable and prudent.

9

10 **Rate Case Adjustments**

11 **Q89. Can you explain the basis for the Rate Case Adjustments in column (d) of**
12 **Exhibit A-13, Schedule C5.3, page 1?**

13 A89. Site security and radiation protection costs were removed from base rates and
14 recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-
15 14399. The Nuclear Surcharge reduction of \$28.6 million as summed on line 24,
16 column (d) accomplishes this requirement. The complete elimination of all financial
17 statement impacts of the Nuclear Surcharge are supported by Witness Uzenski.

18

19 **Q90. Can you explain the basis for the Rate Case Adjustments in column (e) of**
20 **Exhibit A-13, Schedule C5.3, page 1?**

21 A90. The Reclassify PERC adjustment nets to zero as shown on line 24, column (e). This
22 reclassification is performed to make explicit the \$15.0 million PERC Base Expense
23 shown on line 21, column (e) and the \$16.3 million of PERC Regulatory Asset
24 amortization shown on line 22, column (e) are not inflated in the projected

Line
No.

1 adjustments. I will explain the PERC Regulatory Asset mechanism later in my
2 testimony.

3

4 **Adjusted Historical Test Period**

5 **Q91. Can you explain the components that constitute the actual Total Nuclear Power**
6 **Generation O&M expenses for adjusted historical test period in line 24, column**
7 **(g) of Exhibit A-13, Schedule C5.3, page 1?**

8 A91. Total Nuclear Generation O&M of \$191.8 million consists of the Nuclear
9 Organization, PERC Base Expense, amortization of the PERC Regulatory Asset,
10 regulatory assessments and dues, and refueling outage expenses. I detail these
11 expenses for the 2022 historical period on page 2 of Exhibit A-13, Schedule C5.3.

12

13 **Q92. What is the need for and basis of the “Nuclear Organization” expenses that are**
14 **included in the 2022 historic period for Operation and Maintenance Expenses**
15 **on Exhibit A-13, Schedule C5.3, page 2, line 1?**

16 A92. Nuclear Organization expenses are the baseline employee, services and material
17 expenses required to safely and reliably operate Fermi 2. The Nuclear Organization
18 expenses for the historical test period ended December 31, 2022 were \$94.3 million.

19

20 **Q93. What is the need for and basis for the “PERC Base Expense” expenses that are**
21 **included in the 2022 historic period for Operation and Maintenance Expenses**
22 **on Exhibit A-13, Schedule C5.3, page 2, line 2?**

23 A93. As explained and supported by Witness Uzenski, the Commission Order in Case
24 No. U-18014 approved an annual base level of PERC expenses of \$4.9 million for
25 nuclear O&M projects and the Commission Order in Case No. U-20561 increased

Line
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1 the approved annual base level of PERC expenses to \$15.0 million; the PERC Base
2 Expense of \$15.0 million depicted on line 2 recognizes those approvals.

3

4 **Q94. What is the need for and basis for the “Reg Asset Amortization - PERC”**
5 **expenses that are included in the 2022 historic period for Operation and**
6 **Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?**

7 A94. As explained and supported by Witness Uzenski, the Commission Order in Case
8 No. U-18014 approved a regulatory asset for annual PERC projects O&M
9 expenditures that exceed the annual base level of PERC expenses of \$4.9 million
10 for nuclear O&M projects. In Case No. U-20561, the Commission Order updated
11 the approved regulatory asset for annual PERC projects O&M expenditures that
12 exceed the annual base level of PERC expenses of \$15.0 million for nuclear O&M
13 projects. The Order in Case No. U-18014 established the amortization period of this
14 regulatory asset as five years. Consistent with that Order, the \$16.3 million depicted
15 on line 3 is the amount of the PERC Regulatory Asset amortized in 2022.

16

17 **Q95. What is the need for and basis for the “Regulatory Assessments and Dues”**
18 **expenses that are included in the 2022 historic period for Operation and**
19 **Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 4?**

20 A95. A majority of these assessments and dues are regulatory driven, such as those
21 assessments and dues required by the NRC to cover oversight of the plant. In
22 addition, assessments and dues are associated with licensing requirements including
23 the Emergency Response Organization (ERO) and various industry groups.

24

Line
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1 Industry groups include the Institute of Nuclear Power Operations (INPO), which
2 assists utilities in operating nuclear plants to the highest safety standards, the
3 Nuclear Energy Institute (NEI), which assists in common issues impacting the
4 nuclear industry, as well as the Electric Power Research Institute (EPRI) and the
5 General Electric Boiling Water Reactor Owners' Group, both of which sponsor
6 research that is used by nuclear plants to operate more safely and economically.

7

8 The ERO supports the Fermi 2 Emergency Plan which is a license requirement
9 necessary to ensure the health and safety of the public during emergency response
10 events. The ERO funds federal, state and local county emergency facilities in
11 support of the Fermi 2 Emergency Plan.

12

13 **Q96. Which assessments and dues are non-discretionary (i.e. mandated)?**

14 A96. NRC, INPO and ERO assessments and dues are non-discretionary.

15

16 **Q97. Why does the Company pay the discretionary assessments and dues?**

17 A97. Although not specifically mandated, voluntary participation with organizations such
18 as EPRI and NEI are critical within a nuclear business model. In particular,
19 organizations like EPRI that support research and development include sharing of
20 products and services to ensure nuclear asset owners benefit as a whole from shared
21 information. These products and services would be unaffordable without group
22 participation and funding. The role provided by NEI is valuable to plant owners and
23 operators in helping to shape important industry issues and regulation through a
24 coordinated and solidified approach. The nuclear industry clearly recognizes that
25 any one plant can abruptly upset the entire industry due to performance issues. As

Line
No.

1 a result, this industry believes in significant group participation and knowledge
2 sharing to help preclude such an event.

3

4 **Q98. What are some specific benefits that EPRI provides DTE Electric and**
5 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**
6 **Plant?**

7 A98. EPRI provides DTE Electric with the benefit of access to state-of-the-art industry
8 research in the functional areas such as nuclear fuel reliability, reactor vessel and
9 internals aging management, value-based maintenance, training, nuclear risk and
10 safety management, and radiation safety.

11

12 To further provide an example of a specific benefit, EPRI membership is an integral
13 part of DTE Electric's (and indeed the nuclear industry's) probabilistic risk
14 assessment (PSA) program. The PSA engineer qualification at Fermi 2 requires
15 learning the EPRI PSA courses and PSA tools used by DTE Electric such as MAAP
16 5, GOTHIC and PHOENIX, which are all developed and supported by EPRI.
17 Without EPRI membership, DTE Electric would have to develop duplicative PSA
18 education courses and PSA tools which would not be reasonable nor prudent.

19

20 **Q99. What are some specific benefits that NEI provides DTE Electric and**
21 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**
22 **Plant?**

23 A99. NEI provides DTE Electric (as an NEI member) access to its Personnel Access
24 Database System (PADS). NEI membership is required to access PADS. PADS is a
25 database maintained and administered by NEI and contains information provided by

Line
No.

1 PADS participants concerning individuals who request access to a commercial
2 nuclear facility; this information includes dates that an individual was granted or
3 denied access, an individual's training and radiological dosage records. NRC
4 regulations do not require the use of PADS but PADS does offer an efficient method
5 for commercial nuclear plant licensees to comply with NRC regulations at 10 CFR
6 73.56 and to share information about individuals who were denied access or have
7 had their access terminated per NRC regulations. Without access to PADS, DTE
8 Electric would have to create a duplicative system of verifying an individual's plant
9 access history – which would not be reasonable nor prudent.

10

11 NEI also provides DTE Electric with resources known as the Composite Adversary
12 Force (CAF) to support NEI Force-on-Force security inspections. NEI membership
13 is required to use the CAF. Since 2004, the NRC has relied on the NEI CAF to
14 provide a credible, well-trained and consistent mock adversary in Force-on-Force
15 inspections; Force-on-Force inspections assess a nuclear power plant's physical
16 protection measures to defend against a "design-basis treat." To avoid conflicts of
17 interest, the NRC requires a clear separation of functions between the mock
18 adversary and the plant security forces. NRC regulations do not require the use of
19 the NEI CAF but the NEI CAF does provide NEI members with an efficient means
20 for commercial nuclear licensees to conduct NRC Force-on-Force inspections.
21 Without NEI CAF, DTE Electric would be required to establish a duplicative mock
22 adversary force using independent mock adversaries that met NRC standards –
23 which would not be reasonable nor prudent.

24

Line
No.

1 **Q100. How does NEI support safer nuclear operations through collective nuclear**
2 **industry action?**

3 A100. NEI has supported a collective industry response to the events concerning the
4 Fukushima Dai-ichi – in particular, NEI led the nuclear industry’s adoption of the
5 Diverse and Flexible Coping Strategies (FLEX) which increases each plant’s
6 defense-in-depth for beyond-design-basis scenarios. NEI has also led industry
7 efforts to strengthen cybersecurity regulations. Certainly, these initiatives to make
8 nuclear generators safer are in the best interests of our communities and DTE
9 Electric’s association with NEI is reasonable and prudent.

10

11 **Q101. Does DTE Electric use other discretionary memberships to benefit our**
12 **customers and the communities the Company serves?**

13 A101. Yes. An example of another discretionary membership is NUPIC (Nuclear
14 Procurement Issues Corporation) which is a cooperative program for performing
15 and sharing audits of suppliers providing DTE Electric (and the nuclear industry)
16 nuclear-quality parts. NRC regulations (*generally*, Appendix B to Part 50) require
17 NRC licensees such as DTE Electric to audit its suppliers of nuclear-quality parts
18 and maintain an Approved Suppliers List (ASL) – the number of such suppliers is
19 quite large, so NUPIC allows members to use the audits of other members to
20 maintain the suppliers on each licensee’s ASL. Without NUPIC, DTE Electric
21 would be required to audit every supplier listed on its ASL by itself which would
22 not be reasonable nor prudent.

23

24 **Q102. What is the need for and basis for “Total Refueling Outage” expenses for the**
25 **2022 historical period on Exhibit A-13, Schedule C5.3, page 2, line 10?**

Line
No.

1 A102. As discussed earlier in my testimony, the Fermi 2 plant operates on an 24-month
2 refueling cycle such that every 24 months Fermi 2 would shut down to refuel the
3 reactor. The “Total Refueling Outage” expenses are those costs necessary to (1)
4 refuel the Fermi 2 reactor and (2) perform offline maintenance to ensure Fermi 2
5 can operate safely and reliably for the next operating cycle.

6

7 The “Total Refueling Outage” expense consists of the actual refueling outage costs
8 (line 7), the refueling outage accrual (line 8) and the refueling outage accrual
9 reversals (line 9) for the 2022 historical period. Line 10 nets these three components
10 and represents an accounting practice of levelizing incremental refueling expenses
11 by accruing the anticipated refueling expenses over the term of an operating cycle.

12

13 **Q103. Why does DTE Electric levelize its incremental refueling outage expenses?**

14 A103. DTE Electric levelizes its incremental refueling outage expenses so that the
15 difference in expense between outage and non-outage years does not burden DTE
16 Electric customers with large rate fluctuations or create financial swings for the
17 Company. For example, if the Company bases the rate request on the projections
18 for a refueling outage year and all the expenses of that outage appear in that year’s
19 projections, then the Company would be presenting an unnecessarily high cost of
20 providing Fermi 2 generation over the period the rates are in effect. The inverse is
21 also true if the Company used a non-refueling outage year projection for the same
22 purpose. This is consistent with the treatment in prior cases where the Commission
23 has allowed levelized refueling outage expenses in setting rates.

24

Line
No.

1 **Q104. What is the basis for the “Refuel Outage” expense at \$73.1 million for the 2022**
2 **historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?**

3 A104. This is the actual refuel outage expenditures incurred in the 2022 historical period
4 for RF21.

5

6 **Q105. How does DTE Electric manage incremental refueling outage expenses?**

7 A105. The Company manages incremental expenses through structured planning and
8 preparation that is consistent with industry standards and processes. We
9 implemented rigorous financial controls that supported daily management of
10 resources during the execution phase of the refueling outage. This management of
11 resources includes daily reviews of scope completion, schedule and budget. As work
12 completes, contracted resources exit promptly from the site to ensure that costs are
13 controlled.

14

15 **Q106. What is the basis for the “Refuel Outage Accrual” expenses at \$18.4 million for**
16 **the 2022 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line**
17 **8?**

18 A106. This is the actual amount accrued in the historical period for RF21 and RF22.

19

20 **Q107. How does DTE Electric determine the value of the Refuel Outage Accrual?**

21 A107. As the purpose of the Refuel Outage Accrual is to levelize the costs of refueling
22 outages over the appropriate time horizon, DTE Electric developed a model outage
23 template that defines a routine baseline refueling outage in terms of timing, and
24 incremental O&M expenditures for labor, services, materials and other outage costs.
25 It is important to note that the Refuel Outage Accrual is for those incremental O&M

Line
No.

1 costs associated with a refueling outage; routine expenses such as DTE Electric
2 Nuclear Generation strait-time labor, structural overtime and year-round supplier
3 services that are incurred regardless of the outage are “Nuclear Organization.”
4

5 As I will discuss later in my testimony, incremental outage costs that are generally
6 not associated with the baseline outage activities or cause significant variation in
7 outage costs from outage-to-outage are assigned to PERC O&M.
8

9 **Q108. What is the basis for the “Refuel Outage Reversal” of \$38.0 million for the 2022**
10 **historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 9?**

11 A108. This is the actual amount of outage accrual that had been accrued in advance for
12 RF21 and credited to O&M in the historical test period.
13

14 **Projected Adjustments**

15 **Q109. Can you explain the basis for the inflation adjustments in columns (h), (i) and**
16 **(j) on line 24 of Exhibit A-13, Schedule C5.3, page 1?**

17 A109. The labor and material prorated inflation adjustment rates of 3.2% for 2023, 2.9%
18 for 2024 and 2.9% for 2025 are supported by the testimony of Witness Uzenski.
19 Nuclear Generation applied these forecasted inflation rates to the adjusted historical
20 test period costs in column (g).
21

22 **Q110. Can you explain the basis for the Outage Accrual adjustment in column (k) on**
23 **line 24 of Exhibit A-13, Schedule C5.3, page 1?**

24 A110. The Outage Accrual adjustment is to normalize the outage accrual for the projected
25 test period to approximately \$22.5 million. This Outage Accrual adjustment reflects

Line
No.

1 our commitment to improving refueling outage performance and reducing future
2 outage O&M expenditures.

3

4 **Q111. What duration have you projected for RF22?**

5 A111. The 2024 PSCR Plan (Case No. U-21425) projected an outage duration of 45 days
6 for RF22 (projected for spring 2024).

7

8 **Q112. Can you explain the basis for the PERC Amortization adjustment in column**
9 **(l) on line 24 of Exhibit A-13, Schedule C5.3, page 1?**

10 A112. As explained and supported by Witness Uzenski, the Commission Order in Case
11 No. U-18014 not only approved an annual base level of PERC expenses for nuclear
12 O&M projects, but also provided deferral and amortization treatment for any
13 expenses over or under the base amount. The PERC Base expense was changed by
14 \$10.1 million from \$4.9 million per year to \$15.0 million per year in the May 8,
15 2020 Order in Case No. U-20561.

16

17 The PERC Amortization reduction of \$11.4 million in column (l) on line 24 consists
18 of the \$0.0 million change in the approved annual PERC Base Expense as shown in
19 column (l) on line 21 and a forecasted reduction of \$11.4 million in the amortization
20 of the PERC Regulatory Asset as shown in column (l) on line 22.

21

22 The Total PERC Expense for the projected test period is forecasted at \$19.9 million
23 as shown in column (n) on line 23. The derivation of this Total PERC Expense is
24 shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness Uzenski; I

Line
No.

1 detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in Exhibit A-
2 13, Schedule C5.16, page 1.

3

4 **Q113. Can you explain the Total PERC O&M Expenditures detailed in Exhibit A-13,**
5 **Schedule C5.16, page 1?**

6 A113. This exhibit shows the by-project PERC O&M expenditures for the 2022 historical
7 period and projected Calendar Years 2023, 2024, and 2025 planned expenditures
8 totaling \$18.1 million, \$8.9 million, \$22.6 million and \$8.6 million respectively.

9

10 **Q114. Can you explain how DTE Electric determines which projects are included in**
11 **PERC O&M as detailed in Exhibit A-13. Schedule C5.16, page 1?**

12 A114. Exhibit A-13, Schedule C5.16 is the updated list of PERC O&M projects. DTE
13 Electric has provided similar updated exhibits in each of the past rate cases since
14 Case U-18014 established the PERC O&M regulatory asset construct. PERC O&M
15 projects expenditures are those incremental expenditures associated with Nuclear
16 Generation O&M projects. I will provide a rationale for select project's inclusion in
17 the PERC O&M later in my testimony.

18

19 **Q115. How do the Total PERC O&M Expenditures on line 30 of Exhibit A-13,**
20 **Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?**

21 A115. As an example, the projected total PERC O&M expenditures of approximately \$8.9
22 million for Calendar Year 2023 shown in Exhibit A-13, Schedule C5.16, page 1,
23 line 30, column (c) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column
24 (d).

25

Line
No.

1 **Q116. How does the PERC amortization expense on line 15 of Exhibit A-13, Schedule**
2 **C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?**

3 A116. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that
4 was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule
5 C5.17, page 1, line 15, column (g) shows \$4.9 million as the calculated amortized
6 portion of PERC O&M for the 12-month projected test period ending December 31,
7 2025. This \$4.9 million is used in Exhibit A-13, Schedule C5.3, page 1, line 22,
8 column (n).

9

10 **Q117. What was the rationale for the Refueling Outage Planning, Readiness and**
11 **Demobilization project shown on line 1 of Schedule A-13, Schedule C5.16, page**
12 **1?**

13 A117. As I discussed earlier in my direct testimony, DTE Electric begins planning for the
14 upcoming refueling outage at approximately T-24 months prior to the refueling
15 outage. Expenditures for refueling outage planning, scheduling and readiness follow
16 a 24-month pattern and as such, do not lend themselves to a levelized expenditure
17 schedule; the amount of expenditures can also vary from outage-to-outage
18 depending on refueling outage scope. Planning activities include work package
19 planning, work order reviews and resource planning; scheduling includes work plan
20 integration and resource levelization efforts; readiness includes physical tasks such
21 as staging parts, building some scaffolding that can be done prior to the refueling
22 outage, readying temporary power carts, and setting up temporary infrastructure
23 needs such as additional computers and housing trailers. The Refuel Outage
24 Planning line item was included in the original PERC O&M discussion in Case No.

Line
No.

1 U-18014 and has been updated accordingly with each subsequent DTE Electric rate
2 case.

3

4 **Q118. What was the rationale for the Desludge - Torus project shown on line 2 of**
5 **Schedule A-13, Schedule C5.16, page 1?**

6 A118. The torus is a water-filled donut-shaped containment structure designed to absorb
7 excess thermal energy and provide emergency water to the reactor core during a
8 postulated accident scenario. Each refueling outage specially-qualified divers de-
9 sludge the torus to minimize the amount of debris within the torus; this debris
10 normally accumulates over the course of the operating cycle. Once the torus has
11 been de-sludged the divers inspect and repair the submerged coatings of the torus
12 containment structure; the divers also inspect and replace pump suction strainers.
13 The Desludge – Torus project was first included in the PERC O&M exhibit in Case
14 No. U-20162 and has had updated project expenditures included in subsequent rate
15 case PERC O&M exhibits.

16

17 **Q119. What was the rationale for the Reactor Feed Pump Turbine (RFPT)**
18 **Inspections project shown on line 3 of Schedule A-13, Schedule C5.16, page 1?**

19 A119. The Reactor Feed Pump Turbines (RFPTs) require a full tear-down inspection
20 approximately every ten years to satisfy loss control criteria. Fermi 2 has two RFPTs
21 (North and South). Each RFPT drives one Reactor Feed Pump (RFP) which in turn
22 supplies the driving force for reactor feedwater. DTE Electric completed the
23 inspection of the South RFPT in RF21 (2022) and projects to complete the North
24 RFPT inspection in RF22 (2024). The RFPT inspections were first included with

Line
No.

1 the Case No. U-20836 PERC O&M Exhibit and has had updated project
2 expenditures with subsequent rate case PERC O&M exhibits.

3

4 **Q120. What was the rationale for the Residual Heat Removal Heat Exchanger (RHR**
5 **HX) coating project shown on line 4 of Schedule A-13, Schedule C5.16, page 1?**

6 A120. A requirement for the renewed Fermi 2 operating license is to perform inspections
7 of internal coatings of certain piping, piping components, heat exchangers and tanks
8 where the loss of the coating or lining could impact the ability of that equipment to
9 perform its function during the Fermi 2 Period of Extended Operations; the Fermi 2
10 Residual Heat Removal Heat Exchangers (RHR HX) have such internal coatings.
11 Fermi 2 has two RHR HXs ('A' and 'B'), both of which are nuclear-safety
12 equipment. Each RHR HX supports an independent and redundant division of
13 nuclear-safety equipment where the RHR HX transfers residual heat away from the
14 nuclear systems and to the Fermi 2 Ultimate Heat Sink during certain accident
15 scenarios. Previous inspections of the original RHR HX coatings had shown
16 evidence of degradation; therefore, to ensure the RHR HX coatings would support
17 safe operations through 2045 DTE Electric is replacing the internal coatings of the
18 RHR HXs. DTE Electric completed the coating replacement of the RHR HX A in
19 RF21 and projects to complete the replacement of the RHR HX B coating in RF22.
20 The RHR HX coating replacements project was first included with the Case No. U-
21 20836 PERC O&M Exhibit and has had updated project expenditures with
22 subsequent rate case PERC O&M exhibits.

23

Line
No.

1 **Q121. What was the rationale for the Hydraulic Control Unit (HCU) preventative**
2 **maintenance project shown on line 5 of Schedule A-13, Schedule C5.16, page**
3 **1?**

4 A121. The Fermi 2 Hydraulic Control Units (HCUs) require a one-time preventative
5 maintenance (replacement of internal soft components such as diaphragms and
6 gaskets, filters as well as directional control valves) to ensure safe operations
7 through 2045. Fermi 2 has 185 HCUs – one for each control rod drive mechanism
8 (CRDM). The HCU controls hydraulics to the CRDM. DTE Electric has leveled
9 the HCU preventative maintenance over several outages and completed preventative
10 maintenance activities on 37 HCUs in RF21 and projects to complete preventative
11 maintenance activities on 34 HCUs in RF22. The HCU preventative maintenance
12 project was first included with the Case No. U-20162 PERC O&M Exhibit and has
13 had updated project expenditures with subsequent rate case PERC O&M exhibits.

14

15 **Q122. What was the rationale for the Force-on-Force inspections (FOF) shown on line**
16 **6 of Schedule A-13, Schedule C5.16, page 1?**

17 A122. Force-on-Force (FOF) inspections are NRC inspections and exercises that assess the
18 ability a nuclear licensee such as DTE Electric to defend a nuclear power plant from
19 a design-basis-threat. The NRC FOF includes a mock adversary force (MAF) that
20 simulates hostile actions against the plant's security personnel and systems. These
21 NRC FOF inspections occur approximately every three years. The NRC last
22 performed a FOF at Fermi 2 in 2022 and DTE Electric projects the next NRC FOF
23 in 2025. The FOF inspections were first included with the Case No. U-20162 PERC
24 O&M Exhibit and has had updated project expenditures with subsequent rate case
25 PERC O&M exhibits.

Line
No.

1

2 **Q123. What was the rationale for the Integrated Leak Rate Test (ILRT) shown on**
3 **line 7 of Schedule A-13, Schedule C5.16, page 1?**

4 A123. The Integrated Leak Rate Test (ILRT) is an NRC-required evolution to confirm the
5 plant's primary containment system is performing its function (*generally*, Appendix
6 J for Part 50). A licensee such as DTE Electric must perform the ILRT at least once
7 every 15 years – the NRC transitioned to this longer periodicity in 2012 based on
8 research performed by EPRI and surveys conducted by NEI (previously an ILRT
9 was required at least once every ten years), saving the Company (and thus
10 customers) time and money. DTE Electric successfully completed the Fermi 2 IRLT
11 in RF21. The Fermi 2 ILRT was first included with the Case No. U-20836 PERC
12 O&M Exhibit and has had updated project expenditures with subsequent rate case
13 PERC O&M exhibits.

14

15 **Q124. What was the rationale for the High Energy Line Break (HELB) analysis**
16 **shown on line 8 of Schedule A-13, Schedule C5.16, page 1?**

17 A124. Fermi 2 Power Plant is maintained and operated per its NRC license. Supporting the
18 Fermi 2 license are many technical specifications, designs, configuration controls
19 and design calculations. One such design calculation affects environmental
20 (temperature, humidity, pressure) conditions that can be assumed during plant
21 operating scenarios such as a high energy line break (HELB). The HELB analysis
22 updates the Fermi 2 environmental calculations using modern models such as the
23 EPRI GOTHIC which in turn allows DTE Electric to reevaluate and provide
24 additional margin to certain Fermi 2 technical specifications and reduce the
25 likelihood of an unplanned limited condition of operation.

Line
No.

1 **Q125. What was the rationale for the Independent Spent Fuel Storage Installation**
2 **(ISFSI) and ISFSI fuel characterization shown on lines 28 and 13 of Schedule**
3 **A-13, Schedule C5.16, page 1?**

4 A125. Fermi 2 ISFSI campaigns remove spent nuclear fuel assemblies from the Fermi 2
5 spent nuclear fuel pool, load the spent nuclear fuel assemblies into NRC-licensed
6 dry casks, and then transport the dry casks to their interim storage location at the
7 Fermi 2 ISFSI Pad. Prior to loading the spent nuclear fuel assemblies into the casks,
8 DTE Electric must characterize the spent nuclear fuel to ensure the spent nuclear
9 fuel assembly remains intact and that its composition is as expected to ensure the
10 spent nuclear fuel loaded into each cask is consistent with the dry cask license. The
11 2023 ISFSI campaign included 10 dry casks and transitioned 680 spent nuclear fuel
12 assemblies from the Fermi 2 spent fuel pool to the Fermi 2 ISFSI Pad. The ISFSI-
13 related expenditures were first included with the Case No. U-20162 PERC O&M
14 Exhibit and has had updated project expenditures with subsequent rate case PERC
15 O&M exhibits.

16

17 **Q126. What was the rationale for the Spent Fuel Pool (SFP) cleanup campaign shown**
18 **on line 14 of Schedule A-13, Schedule C5.16, page 1?**

19 A126. The Fermi 2 Spent Fuel Pool (SFP) is a small, water-filled pool adjacent to the
20 reactor and is used to store spent nuclear fuel, incoming new nuclear fuel, control
21 rod blades (CRBs) and nuclear instrumentation equipment such as dry tubes and
22 local power range monitors (LPRMs). While ISFSI campaigns transition spent
23 nuclear fuel from the SFP to dry-cask storage, the SFP storage locations for CRBs
24 and nuclear instrumentation equipment are also finite and periodically DTE Electric
25 must dispose of this depleted equipment to clear space for the CRB/SRM/IRM

Line
No.

1 removals projected in upcoming refueling outages. DTE Electric removed and
2 disposed 28 CRBs and 7 dry tubes and 3 LPRMs from the SFP. The SFP cleanup
3 campaigns were first included with the Case No. U-20162 PERC O&M Exhibit and
4 has had updated project expenditures with subsequent rate case PERC O&M
5 exhibits. DTE Electric projects the next SFP campaign to occur around the year
6 2030.

7

8 **Q127. What was the rationale for the Core Shroud Inspections shown on line 17 of**
9 **Schedule A-13, Schedule C5.16, page 1?**

10 A127. The core shroud is a cylindrical shroud that directs coolant flow through the core
11 and helps maintain fuel alignment to ensure control rods can be inserted into the
12 core. DTE Electric performs core shroud inspections approximately every ten years
13 to monitor the integrity of the core shroud per EPRI guidelines endorsed by the
14 NRC; however, with Fermi 2's transition to the 24-month cycle, DTE Electric was
15 required to perform the core shroud inspections one outage year earlier than
16 otherwise required. DTE Electric projects to perform the core shroud inspections in
17 RF22. DTE Electric last performed the core shroud inspection in RF18 (2017) which
18 was depicted in the Case No. U-20162 PERC O&M exhibit.

19

20 **Q128. What was the rationale for the License Renewal Inspections shown on line 27**
21 **of Schedule A-13, Schedule C5.16, page 1?**

22 A128. Once Fermi 2 transitions to its Period of Extended Operations in 2025, the capital
23 project License Renewal Implementation will complete and be in service. There will
24 be ongoing incremental inspections required as a part of the Fermi 2 renewed license
25 which DTE Electric will account for in the License Renewal Inspection project. The

Line
No.

1 License Renewal Inspection project was included in the Case No. U-21297 PERC
2 O&M Exhibit.

3

4 **Q129. What was the rationale for the Feed Water Heater (FWH) Bridging Strategy**
5 **project analysis shown on line 20 of Schedule A-13, Schedule C5.16, page 1?**

6 A129. I have discussed the technical importance of the FWHs in the capital discussion.
7 Emergent repairs to the #3S FWH were performed in RF20. DTE Electric performed
8 inspections of these six FWHs in RF21 to support safe, reliable operation until
9 RF22. DTE Electric is projecting to perform inspections and repairs to the #3S, #3N,
10 #4S, #4N, #5S and #5N FWHs to support reliable operation until these six FWHs
11 are replaced in RF23 and RF24. This proceeding is the first inclusion of the FWH
12 Bridging Strategy expenditures as PERC O&M.

13

14 **Q130. What was the rationale for the Circulating Water Pump (CWP)**
15 **refurbishments shown on line 21 of Schedule A-13, Schedule C5.16, page 1?**

16 A130. The Fermi 2 Circulating Water Pumps (CWP) and motors require refurbishment
17 approximately every 10 years to ensure reliable operation. Fermi 2 Power Plant has
18 five CWPs, each driven by a 5000-horsepower motor, that supply the driving force
19 for the Fermi 2 Circulating Water System. In general, Fermi 2 Power Plant only
20 requires four of the five CWPs to be at full-power operations during the cooler
21 months of October – April. It's during this time that DTE Electric can remove a
22 CWP from service, ship the pump and motor offsite for refurbishment, and then
23 reinstall the pump and motor prior to the warmer months when all five CWPs are
24 required for full-power operations. The CWP refurbishments were first included

Line
No.

1 with the Case No. U-20162 PERC O&M Exhibit and has had updated project
2 expenditures with subsequent rate case PERC O&M exhibits.

3

4 **Q131. What was the rationale for the High Pressure Turbine (HPT) inspection shown**
5 **on line 25 of Schedule A-13, Schedule C5.16, page 1?**

6 A131. The High Pressure Turbine (HPT) requires a full tear-down inspection
7 approximately every 120,000 hours of operation to satisfy loss control criteria. The
8 Fermi 2 main turbine system consists of a high pressure element (the HPT) in
9 tandem with three low-pressure elements (low-pressure turbines (LPTs)). DTE
10 Electric projects to complete the HPT inspection in RF23 (2026). The HPT
11 inspections were first included with the Case No. U-20162 PERC O&M Exhibit and
12 has had updated project expenditures with subsequent rate case PERC O&M
13 exhibits.

14

15 **Q132. What was the rationale for the 24-Month Operating Cycle project shown on**
16 **line 11 of A-13, Schedule C5.16, page 1?**

17 A132. The 24-month operating cycle project reduces the frequency of Fermi 2 refueling
18 outages and improves operating time. Operating on a 24-month cycle results in three
19 refueling outages every six years; operating on an 18-month operating cycle results
20 in four refueling outages every six years. Prior to the 24-month operating cycle
21 project, Fermi 2 previously operated with 18-month operating cycles; therefore,
22 transitioning to a 24-month operating cycle results in additional generation over a
23 six-year cycle due to fewer refueling outages.

24

Line
No.

1 Fermi 2's cycle length is limited by our NRC license. The 24-Month Operating
2 Cycle project performed an analysis to ensure the plant could operate 24 months
3 between refueling outages and submitted that analysis as a license amendment
4 request to the NRC to update the Fermi 2 license to allow a 24-month cycle. DTE
5 Electric received NRC approval in early 2021 and began its first 24-month operating
6 cycle in 2022 upon exiting RF21.

7

8 The Company first introduced the 24-Month Operating Cycle project in Case No.
9 U-20162. The Commission responded favorably and approved cost recovery
10 associated with the 24-Month Operating Cycle project in the Case No. U-20162
11 Order dated May 2, 2019.

12

13 **Q133. What are the Total Nuclear Power Generation O&M expenses that you support**
14 **for the projected test period ending December 31, 2025?**

15 A133. I support Total Nuclear Power Generation O&M expenses of \$159.4 million for the
16 projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line 24,
17 column (n). As I have discussed previously, these projected Total Operation and
18 Maintenance expenses are required for the safe and reliable operation of Fermi 2 for
19 the projected test period. I consider these expenses to be prudent and reasonable.

20

21 **Nuclear Surcharge**

22 **Q134. Is the Company requesting a change to the Nuclear Surcharge?**

23 A134. Only with respect to inflation for the Site Security and Radiation Protection portion
24 of the Nuclear Surcharge. The Company is proposing an updated Nuclear Surcharge
25 based on the same approach approved by the Commission in Case Nos. U-17767,

Line
No.

1 U-18014, U-18255, U-20162, U-20561, U-20836 and U-21297 and depicted in
2 Exhibit A-20, Schedule J1.

3
4 The Site Security and Radiation Protection portion of the surcharge has been
5 updated to reflect 2022 historical expense adjusted for inflation on line 2. The
6 inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.

7
8 The Nuclear Decommissioning Funding portion of the surcharge shown on line 3 is
9 unchanged.

10
11 The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual
12 surcharge shown on line 4 is unchanged.

13
14 The resulting nuclear surcharge set forth in Company rates is supported by Company
15 Witness Willis on Exhibit A-16, Schedule F6.

16

17 **Q135. What is the Nuclear Surcharge that you support for the 12-month projected**
18 **test period ending December 31, 2025?**

19 A135. I support the Proposed Nuclear Surcharge of \$40.1 million for the projected test
20 period as shown in Exhibit A-20, Schedule J1, page 1, line 5, column (b); this
21 represents a change of approximately \$1.2 million from the current authorized
22 Nuclear Surcharge shown on line 6, column (b). The Proposed Nuclear Surcharge
23 funds Fermi 2 site security, radiation protection, nuclear decommissioning and the
24 disposal of LLRW; these activities are required for safe and secure operation of the

Line
No.

- 1 Fermi 2 Power Plant for the projected test period. I consider the Proposed Nuclear
- 2 Surcharge to be prudent and reasonable.
- 3
- 4 **Q136. Does this complete your direct testimony?**
- 5 A136. Yes, it does.

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JEFFREY C. DAVIS

Line
No.

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

3 A1. My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North
4 Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric
5 Company at the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic
6 Business Operations.

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. The purpose of my rebuttal testimony is to rebut the positions of Witness Kindschy
15 who provided direct testimony on behalf of the Michigan Public Service
16 Commission (MPSC) Staff (Staff) and of Witness Coppola who provided direct
17 testimony on behalf of the Michigan Attorney General (AG). Specifically, my
18 rebuttal will address both Witness Kindschy's and Witness Coppola's proposed
19 disallowances of Nuclear Generation capital expenditures.

20

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

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-47	LLI	Nuclear Production Plant
A-47	LL2	Nuclear Fuel Expenditures

Line
No.

1 **Q5. Were these exhibits prepared by you or under your direction?**

2 A5. Yes, they were.

3

4 **NUCLEAR GENERATION CAPITAL EXPENDITURES**

5 **Q6. Why are you rebutting the direct testimonies of Witness Kindschy and Witness**
6 **Coppola relative to the Nuclear Generation capital expenditures?**

7 A6. Taken together, the proposed Nuclear Generation capital expenditures
8 disallowances proposed by Witness Kindschy and Witness Coppola represent an
9 imprudent and unreasonable reduction of approximately \$181.4 million in Nuclear
10 Generation's projected project capital expenditures. Nuclear Generation's
11 projected project capital expenditures for the 24-month-period-ending December
12 31, 2025, in total, were approximately \$263.6 million so these proposals would
13 eliminate nearly 70% of the Company's projected capital expenditures for two
14 years at the Fermi 2 Power Plant (Fermi 2). The Company's proposed expenditures
15 are consistent, both operationally and economically, with historical capital
16 deployment at Fermi 2.

17

18 Additionally, Witness Coppola proposed a reduction of approximately \$20.0
19 million of nuclear fuel expenditures against DTE Electric's projected nuclear fuel
20 expenditures for the 24-month-period-ending December 31, 2025, of
21 approximately \$137.1 million.

22 Both Witness Kindschy's and Witness Coppola's proposed disallowances were
23 reached by applying a series of inappropriate conclusions which I will individually
24 rebut later in my testimony.

Line
No.

1 **Q7. Are there overlapping proposed capital reductions between Staff Witness**
2 **Kindschy's proposed reduction of approximately \$45.6 million and AG**
3 **Witness Coppola's proposed reduction of approximately \$175.4 million of**
4 **Nuclear Generation capital expenditures?**

5 A7. Yes, there is overlap in proposed Nuclear Generation capital expenditures
6 reductions between Witness Kindschy's proposals and Witness Coppola's
7 proposals. To simplify my rebuttal testimony, I plan to address each proposed
8 reduction on its own independent merits.

9

10 **MPSC STAFF PROPOSALS**

11 **Q8. What are your thoughts concerning Witness Kindschy's proposed reductions**
12 **of approximately \$45.6 million of Nuclear Generation from rate base?**

13 A8. The proposed removal of approximately \$45.6 million of Nuclear Generation
14 capital expenditures would not be reasonable and would not be prudent.

15

16 Nuclear Generation projects support the safe and reliable operation of the Fermi 2
17 Power Plant. I supported the reasonableness of the Nuclear Generation Projects
18 with the total historical period actual expenditures of approximately \$254.5 million,
19 and the projected capital expenditures of approximately \$339.5 million and \$80.1
20 million for the 24-month bridge period ending December 31, 2024, and the 12-
21 month projected test period ending December 31, 2025 respectively as depicted on
22 line 4, page 1 of Exhibit A-12, Schedule B5.3, in my direct testimony, augmented
23 by the Part III documents and other supporting documentation such as design
24 documents, commercial agreements and internal capital appropriations
25 authorizations provided in the due course of this proceeding.

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1 The Commission should not adopt Witness Kindschy's proposals so that DTE
2 Electric can continue with its work plans to operate the Fermi 2 Power Plant safely
3 and reliably as discussed in my direct testimony.

4

5 **Q9. How did Witness Kindschy arrive at the proposed capital expenditure**
6 **reduction of approximately \$45.6 million of Nuclear Generation capital**
7 **expenditures?**

8 A9. Witness Kindschy proposed capital expenditure reductions of approximately
9 (summarized by Witness Kindschy in Exhibit S-16.3):

- 10 • \$15.7 for Nuclear Generation capital expenditures for the 5-month period
11 ending April 30, 2024 (divided \$7.9 million for Routine and Small Projects
12 and \$7.9 million for Non-Routine and Large Projects)
- 13 • \$13.6 million for Nuclear Generation capital expenditures for the 7-month
14 period ending December 31, 2024 (divided as \$3.7 million for Routine and
15 Small Projects and \$9.9 million for Non-Routine and Large Projects)
- 16 • \$16.2 million for Nuclear Generation capital expenditures for the 12-month
17 period ending December 31, 2025 (divided \$8.5 million for Routine and
18 Small Projects and \$7.7 million for Non-Routine and Large Projects)

19

20 **Q10. What are your thoughts concerning Witness Kindschy's conclusion?**

21 A10. Witness Kindschy's conclusions are built upon three misconceptions: (1) Nuclear
22 Generation's project expenditure variances-to-plan (actuals compared to
23 projections provided in this electric rate case) for the 5-month period ending April
24 30, 2024 were not due to timing but rather due to performance, (2) then using those
25 misunderstood project expenditure variances-to-plan as her support to infer Nuclear

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1 Generation systematically projects its capital project expenditures on the high-side
2 of any expenditure uncertainty, and (3) then proposing as a remedy to remove this
3 perceived systematic high-side projection by the use of a certain project
4 management estimating model that is not applicable to Nuclear Generation
5 projected capital expenditures as depicted in Exhibit A-12, Schedule B5.3.

6

7 **Q11. What do you mean by timing and performance variance?**

8 A11. Timing variance means work has completed or will be completed at the projected
9 expenditure, but the timing of this projected expenditure is sooner or later than
10 expected. In contrast, performance variance means the work has completed or will
11 complete at an actual expenditure higher or lower than expected.

12

13 As Witness Kindschy is proposing broad reductions to the entire Nuclear
14 Generation portfolio of projects, I will take a moment to discuss individual project
15 timing impacts in the context of portfolio management. While prudent management
16 of a portfolio of projects certainly requires an understanding of the basis for the
17 timing variance; it would be unreasonable and not prudent to change or manage the
18 priorities of the portfolio based on timing variances as these timing variances can
19 reasonably be expected to converge to plan. Conflating timing variances and
20 performance variances within the greater portfolio management regime can lead to
21 non-optimal execution of priorities – it is after a project has completed or will
22 complete higher or lower in cost than projected that priorities are reevaluated to
23 achieve targeted expenditures (reference my direct testimony at line 12 of JCD-47).
24 None of Witness Kindschy's proposed reductions address a circumstance at Fermi
25 2 involving a performance variance.

Line
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1 **Q12. Why else do you mention reasonable and prudent “portfolio of projects”**
2 **rather than just reasonable and prudent management of individual projects?**

3 A12. As a noteworthy example, Nuclear Generation capital projects that are being
4 implemented during a refueling outage – because of the highly-integrated nature of
5 refueling outages – must be managed as an integrated portfolio of capital projects.
6 The execution of the refueling outage itself and the management of the overall
7 portfolio target expenditures provides for optimized decision-making versus
8 managing variances (timing or performance) on a project-by-project level.

9

10 **Q13. How does the “highly-integrated nature of refueling outages” impact**
11 **individual projects?**

12 A13. As I stated in my direct testimony, DTE Electric manages incremental supplier
13 personnel as a total. Individual projects must share these resources (such as
14 scaffolders, insulators, radiation protection, etc.) and as an outage schedule updates,
15 these resources are likely to be used by the projects in variance to the individual
16 projections, yet the total resource usage remains controlled per total refueling
17 outage capital projections. So, although individual capital projects may have
18 variance, the whole of the capital projects implemented during the refueling outage
19 will be on plan.

20

21 **Q14. Why would controlling resources in total be reasonable and prudent during a**
22 **refueling outage?**

23 A14. This is the most reasonable and prudent approach to managing and controlling the
24 timing of the work performed during a refueling outage. In the alternative – if DTE
25 Electric managed resources to each individual project cost projection, then that

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1 would require each individual project to have dedicated resources that could not be
2 shared – which would decrease resource efficiency, increase the total costs of each
3 project and increase Nuclear Generation’s capital expenditures in general – which
4 would not be reasonable and not prudent.

5

6 **Q15. What are your thoughts concerning Witness Kindschy’s proposed reductions**
7 **based on Nuclear Generation’s actual capital expenditures for the 5-month**
8 **period ending April 30, 2024?**

9 A15. Witness Kindschy inappropriately treats timing variances for the 5-month period
10 ending April 30, 2024, as permanent under-spends (performance variances). The
11 Fermi 2 Refueling Outage 22 (RF22) was in progress during April 2024 which
12 Witness Kindschy did not factor in her variance analysis. As I explained in my
13 direct testimony: (1) at line 12 of JCD-47, “Nuclear Generation manages capital
14 expenditures for the period and expected capital expenditures in total will be
15 incurred as projected” as in the period through the projected test year and (2) at line
16 21 of JCD-8, “Work such as capital replacements and modifications are
17 implemented when the plant is in the safest condition to do so. For most of our work
18 at Nuclear Generation, that safest condition is when the Fermi 2 plant is shut down
19 for a refueling outage.”

20

21 Nuclear Generation capital expenditures peak during the refueling outages. Capital
22 expenditures in the months leading up to and through a refueling outage constitute
23 most Nuclear Generation capital expenditures for the 24-month cycle. In fact,
24 capital expenditures within the refueling outage are not homogenous with respect
25 to schedule and can vary each outage. Generally speaking, capital expenditures

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1 during a refueling outage peak early in the refuel outage as that's when the material
2 is being withdrawn from the warehouse and when the maximum number of
3 incremental supplier personnel is on site, as the outage progresses incremental
4 supplier personnel demobilize as the scope completes and daily capital costs trend
5 lower, then capital costs peak again at the end of the refueling outage schedule as
6 plant components such as the reactor vessel, the drywell and the turbine systems
7 are returned to operations and associated capital costs are recognized. It is simply
8 not possible to draw an accurate conclusion as to total capital expenditures at a
9 nuclear plant by using monthly capital expenditures using only a portion of a
10 refueling outage actual costs – which is what Witness Kindschy did with her 5-
11 month period ending April 30, 2024 project variance analysis.

12

13 **Q16. When is a reasonable time following a refueling outage to review the capital**
14 **expenditures and make final assessments of the variances?**

15 A16. Three months following a refueling outage is generally sufficient time to allow all
16 final invoices to be receipted and to minimize timing variances. In the case of RF22,
17 which completed in May 2024, the three months would be complete with the
18 business close of July 2024.

19

20 **Q17. What were Nuclear Generation capital expenditures for the 8-month period**
21 **ending July 31, 2024?**

22 A17. Exhibit A-47, Schedule LL1 Nuclear Generation Capital Expenditures updates
23 DTE Electric's actual Nuclear Generation capital expenditures that Witness
24 Kindschy included in her Exhibit S-16.6 to include May, June, and July 2024
25 expenditures. The \$160.4 million depicted at line 4, column (j), page 1 of Exhibit

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1 A-47, Schedule LL1 is the total Nuclear Generation project capital expenditures for
2 the 8-month period ending July 31, 2024. The \$162.8 million depicted at line 5,
3 column (j), page 1 of Exhibit A-47, Schedule LL1 is the total Nuclear Generation
4 project capital expenditures for the 8-month period ending July 31, 2024, as
5 projected in the Exhibit A-12, Schedule B5.3. DTE Electric's Nuclear Generation
6 total capital expenditures for this 8-month period was essentially on plan.

7

8 **Q18. How should the Commission evaluate the Nuclear Generation actual**
9 **expenditures through July 2024 and the projected test period?**

10 A18. DTE Electric has reasonably and prudently completed its implementation of the
11 RF22 scope as projected in my direct testimony. I have demonstrated that Nuclear
12 Generation's capital expenditures through RF22 were at projected amounts after
13 accounting for timing associated with RF22; therefore, the Commission should not
14 adopt Witness Kindschy's proposed reduction of approximately \$15.7 million for
15 Nuclear Generation for the 5-month period ending April 30, 2024. Also, since
16 Witness Kindschy relied at least in part on timing variances of Nuclear
17 Generation's capital expenditures to justify further reductions in projected capital
18 expenditures, I would recommend the Commission not adopt Witness Kindschy's
19 proposed reductions for the 7-month period ending December 31, 2024, and the 12-
20 month period ending December 31, 2025, as well.

21

22 **Q19. Setting aside the timing variance for a moment, is Witness Kindschy correct**
23 **in concluding that Nuclear Generation includes high-side over-projections in**
24 **its expenditures depicted in Exhibit A-12, Schedule B5.3?**

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1 A19. No. As I stated in my direct testimony, Nuclear Generation removes all
2 contingencies from rate case exhibits; further, I state in direct testimony at line 25
3 of JCD-46 “some known scope with highly uncertain costs have projected
4 expenditures excluded from exhibits. DTE Electric takes reasonable and prudent
5 measures to depict capital expenditures as they are projected to be incurred.”

6

7 **Q20. Are you generally aware of the Association of Advancement of Cost**
8 **Engineering (AACE) estimating techniques used by Witness Kindschy as a**
9 **basis for proposed Nuclear Generation capital reductions of approximately**
10 **\$29.8 million?**

11 A20. Yes, to the extent of the information provided in Witness Kindschy’s direct
12 testimony and exhibits. The Association of Advancement of Cost Engineering
13 International (AACE) is one of several organizations that provide professional
14 development and certification for professional cost engineers. Witness Kindschy
15 referenced an AACE document titled AACE International Recommended Practice
16 No. 18R-97 titled, “COST ESTIMATE CLASSIFICATION SYSTEM – AS
17 APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR
18 THE PROCESS INDUSTRIES” (AACE Process Industries Recommended
19 Practices) as Exhibit S-16.3.

20

21 On page 2 of the AACE Process Industries Recommended Practices (page 3 of
22 Kindschy Exhibit S-16.3) is a table labeled “COST ESTIMATE
23 CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES” that provides
24 a summary of AACE’s estimate “classes” and their associated primary
25 characteristic and secondary characteristics. Witness Kindschy’s primary focus is

Line
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1 towards each AACE estimate class and its associated secondary characteristic of
2 “expected accuracy range.”

3

4 To formulate a proposed disallowance for Nuclear Generation’s projected
5 expenditures for the 8-month period ending December 31, 2024, Witness Kindschy
6 applied a 15% value found in the AACE estimate class 4 secondary characteristic
7 Expected Accuracy Range.

8

9 To formulate a proposed disallowance for Nuclear Generation’s projected
10 expenditures for the 12-month period ending December 31, 2025, Witness
11 Kindschy applied a 20% value found in the AACE estimate class 5 secondary
12 characteristic Expected Accuracy Range.

13

14 **Q21. Are there aspects of the AACE Process Industries Recommended Practices**
15 **that are inconsistent with my explanation of Nuclear Generation’s and the**
16 **Commission’s practice concerning contingencies?**

17 A21. Yes. Note [a] of the COST ESTIMATE CLASSIFICATION MATRIX FOR THE
18 PROCESS INDUSTRIES (page 3 of Kindschy Exhibit S-16.3) clarifies, “The state
19 of process technology and availability of applicable reference cost data affect the
20 range markedly. The +/- value represents typical percentage variation of actual
21 costs from the cost estimate after application of contingency (typically at a 50%
22 level of confidence) for given scope.” (Emphasis added). As I confirm in my direct
23 testimony, Nuclear Generation capital expenditures exclude contingencies.

Line
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1 **Q22. Does the AACE Process Industries Recommended Practices provided in**
2 **Witness Kindschy's Exhibit S-16.3 indicate an intention that it is appropriate**
3 **for to application to projects for operating nuclear power plants?**

4 A22. No. Page 1 of the AACE Process Industries Recommended Practices (page 2 of
5 Witness Kindschy's Exhibit S-16.3) states "This addendum to the generic
6 recommended practice provides guidelines for applying the principles of estimate
7 classification specifically to project estimates for *engineering, procurement, and*
8 *construction (EPC)* work for the *process industries*" emphasis added where process
9 industry generally refers to industries such as oil refinery or production of
10 chemicals and EPC generally refers to larger turnkey construction projects (note:
11 none of the Nuclear Generation capital expenditures depicted in Exhibit A-12,
12 Schedule B5.3 would be considered EPC/turnkey).

13

14 **Q23. Did Witness Kindschy otherwise discuss how she chose to use the AACE**
15 **estimating techniques for her proposed disallowances?**

16 A23. No. It is unclear how AACE estimating techniques became Witness Kindschy's
17 preferred method for identifying projected cost uncertainties. In reference to justify
18 applying the AACE estimate classes 4 and 5 to projected Nuclear Generation
19 capital expenditures, Witness Kindschy note son page 11 of her direct testimony at
20 line 3 "Staff's recommended reductions to 2024 and 2025 are further supported by
21 the comparison of the actual capital expenditures through April 2024 to what the
22 Company included in its case."

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1 **Q24. Does the timing variances identified by Witness Kindschy confirm the**
2 **appropriateness of Nuclear Generation's use of the AACE estimating**
3 **techniques?**

4 A24. No. As I discussed earlier, the Nuclear Generation's timing variances have been
5 minimized following the conclusion of RF22 and capital expenditures for the 8-
6 month period ending July 31, 2024, were approximately to plan. Any variance for
7 the 5-month period ending April 30, 2024, was coincidental and not indicative of
8 Nuclear Generation using capital expenditure projections with uncertainties
9 bounded by AACE Process Industries Recommended Practices.

10

11 **Q25. Are the Company's Nuclear Generation capital project expenditures created**
12 **by AACE-certified cost engineers or by applying the standards recommended**
13 **by AACE?**

14 A25. No.

15

16 **Q26. If Nuclear Generation capital expenditure projections are not provided by**
17 **AACE-certified cost engineers, is the Company confident the expenditures will**
18 **be incurred as projected?**

19 A26. Nuclear capital expenditure projections are, in general, relatively straight forward
20 application of quantities multiplied by rates distributed in time based on scheduled
21 resource use. Many Nuclear Generation projects are routine capital replacements,
22 DTE Electric has executed this work since operations began and will continue to
23 execute this work for as long as operations continue to support safe and reliable
24 operations. As I discussed in my direct testimony, contracts for work and materials
25 are well established (so unit rate is well-defined) and materials and labor schedules

Line
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1 are planned months in advance (so resource use is well-defined). Nuclear
2 Generation's expectation, as it is across the nuclear industry, is to adhere to the
3 schedule; therefore, DTE Electric is confident in its capital expenditure projections.
4

5 **Q27. How would you characterize the Nuclear Generation capital expenditures**
6 **depicted in Exhibit A-12, Schedule B5.3 for each project?**

7 A27. I think it would be appropriate and fair to characterize the Nuclear Generation
8 capital expenditures depicted in Exhibit A-12, Schedule B5.3 as already
9 representing the lower bound of a reasonable expenditure projection for each
10 project. Further reduction by applying a non-applicable standard would result in an
11 unreasonable and imprudent reduction in Nuclear Generation's capital
12 expenditures.
13

14 **Q28. Are there other considerations with respect to Witness Kindschy's proposed**
15 **reductions?**

16 A28. Yes. Witness Kindschy's generalized proposed reductions apply to all Nuclear
17 Generation projects, including those projects that will not be in service until beyond
18 the projected test period. As DTE Electric Witness Uzenski explains in her rebuttal
19 testimony on page TMU-8-Reubttal, "such disallowances should have no impact"
20 to DTE Electric's requested rate relief.
21

22 **ATTORNEY GENERAL PROPOSALS**

23 **Q29. What are your thoughts concerning Witness Coppola's proposed reductions**
24 **of approximately \$175.4 million of Nuclear Generation capital from rate base?**

Line
No.

1 A29. The proposed removal of approximately \$175.4 million of Nuclear Generation
2 capital expenditures would not be reasonable and would not be prudent.

3
4 Nuclear Generation projects support the safe and reliable operation of the Fermi 2
5 Power Plant. I supported the reasonableness of the Nuclear Generation Projects
6 with the total historical period actual expenditures of approximately \$254.5 million,
7 and the projected capital expenditures of approximately \$339.5 million and \$80.1
8 million for the 24-month bridge period ending December 31, 2024, and the 12-
9 month projected test period ending December 31, 2025 respectively as depicted on
10 line 4, page 1 of Exhibit A-12, Schedule B5.3, in my direct testimony, augmented
11 by the Part III documents and other supporting documentation such as design
12 documents, commercial agreements and internal capital appropriations
13 authorizations provided in the due course of this proceeding.

14
15 The Commission should not adopt Witness Coppola's proposals so that DTE
16 Electric can continue with its work plans to operate the Fermi 2 Power Plant safely
17 and reliably as discussed in my direct testimony.

18

19 **Q30. How did Witness Coppola arrive at the proposed reduction of approximately**
20 **\$175.4 million of Nuclear Generation capital expenditures?**

21 A30. Witness Coppola proposed reductions of approximately:

- 22 • \$83.9 million for Nuclear Generation projects that will be placed into
23 service beyond the projected test period (Witness Coppola's direct
24 testimony at line 2-3, page 46)

Line
No.

- 1 • \$41.1 million for the Plant Radio System (Witness Coppola's direct
- 2 testimony at line 12-13, page 42) and Security Computer System projects
- 3 (Witness Coppola's direct testimony at line 8-9, page 40)
- 4 • \$24.0 million for Natural Draft Cooling Towers, Document Management
- 5 System Enhancements, and Remote Monitoring projects (Witness
- 6 Coppola's direct testimony at line 16, page 45)
- 7 • \$20.0 million for nuclear fuel (Witness Coppola's direct testimony at line
- 8 4, page 44), and
- 9 • \$6.5 million for Sanitary Sewer System work (Witness Coppola's direct
- 10 testimony at line 9, page 46)

11

12 **Q31. What are your thoughts concerning Witness Coppola's proposal to reduce**
13 **approximately \$83.9 million of rate base for Nuclear Generation projects that**
14 **DTE Electric plans to place into service after the projected test period?**

15 A31. My direct testimony supports the reasonableness and prudence of these project
16 expenditures. Witness Coppola appears to be making only an accounting argument
17 as the basis for excluding these projects, so I refer to DTE Electric Witness
18 Uzenski's discussion on page TMU-8-Rebuttal that confirms that "projects that do
19 not go into service during the projected test period have no impact on the
20 Company's revenue requirement and deficiency." DTE Electric added the in-
21 service year projection to Exhibit A-12, Schedule B5.3, pages 2 - 4 to be transparent
22 about project in-service dates and impact to revenue requirement.

23

Line
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1 **Q32. What are your thoughts concerning Witness Coppola's proposal to reduce**
2 **approximately \$41.1 million of capital expenditures for the Security System**
3 **Computer and Plant Radio Projects?**

4 A32. Witness Coppola apparently misunderstood the internal capital appropriations
5 request forms that the Company provided and misinterprets an initial partial
6 appropriation for a baseline budget. This misunderstanding causes Witness
7 Coppola to incorrectly assert that the Security System Computer and Plant Radio
8 projects have incurred or are projected to incur unreasonable or imprudent
9 expenditures.

10

11 **Q33. What was the baseline budget for the Security Computer System?**

12 A33. As depicted on page 2 of Witness Coppola's confidential Exhibit AG-9, the initial
13 baseline budget for the Security System Computer project was approximately \$25.2
14 million. This appropriation was internally approved on January 26, 2023.

15

16 **Q34. Can you explain the \$9,948,000 amount for the Security System Computer**
17 **referenced by Witness Coppola?**

18 A34. The approximately \$9.9 million referenced by Witness Coppola was an initial
19 partial appropriation approval to initiate the project. The initial appropriation was
20 only sufficient to start the project and develop the information required to develop
21 the baseline budget and present the project for full project authorization. This is a
22 reasonable practice when the necessity and reasonableness of the intended work is
23 not in doubt, as is often the case in Nuclear Generation.

24

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1 **Q35. Is an initial partial appropriation prior to requesting a full baseline budget**
2 **standard practice?**

3 A35. Yes. It is standard practice to authorize larger project capital expenditures in
4 tranches so that the initial baseline budget once authorized can be used to measure
5 changes in scope, schedule, and budget.

6

7 **Q36. What were the initial partial appropriation and the baseline budget for the**
8 **Plant Radio project?**

9 A36. As depicted on page 2 of Witness Coppola's confidential Exhibit AG-10, the initial
10 baseline budget for the Plant Radio System project was approximately \$15.8
11 million. The initial partial appropriation for Plant Radio System was \$6.0 million.
12 This appropriation (baseline budget) was internally approved October 28, 2022.

13

14 **Q37. Why does the initial baseline budget authorization for the Plant Radio System**
15 **include only a narrative that stated, "Requesting total appropriations costs**
16 **associated with Plant Radios Mod for alignment with 8+4 2022 forecast?"**

17 A37. Appropriation forms are internal DTE documents, the scope of the Plant Radio
18 System project was generally understood so additional narrative was not provided.
19 As this appropriation form was to authorize the baseline line budget, the narrative
20 included states that the change is for "appropriations total costs" vs partial
21 appropriations.

22

23 **Q38. What were the total expenditures depicted in rate cases for the Plant Radio**
24 **System and Security System Computer projects?**

Line
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1 A38. Both projects were initially presented to the Commission in DTE Electric rate Case
2 No. U-20836. The total amount depicted in U-20836, Exhibit A-12, Schedule B5.3
3 for the Security System Computer project was \$24.8 million. The total amount
4 depicted in Case No. U-20836, Exhibit A-12, Schedule B5.3 for Plant Radio
5 System project was \$8.1 million. DTE Electric again depicted these projects in DTE
6 Electric rate Case No. U-21297 Exhibit A-12, Schedule B5.3 at \$23.9 million and
7 \$11.9 million for the Security System Computer and Plant Radio System projects,
8 respectively.

9

10 **Q39. Does the recently authorized Security System Computer project**
11 **appropriations (page 4 of Witness Coppola's confidential Exhibit AG-9)**
12 **request accurately describe why the project changed its baseline budget from**
13 **approximately \$25 million to \$39 million?**

14 A39. Yes. The recently authorized Security System Computer project appropriation to
15 increase the project's baseline costs to approximately \$39.2 million includes a
16 description of nine items that changed relative to the original baseline budget. Most
17 notable is the design and implementation of the Secured Owner Controlled Area
18 (SOCA) building as these expenditures were uncertain in prior rate cases and
19 excluded from previous projections. Other updates to scope and schedule such as
20 to use a more reliable technology for intrusion detection and to use recent operating
21 experience to add a fully integrated system site acceptance test prior to in-servicing
22 the project are reasonable and prudent updates to the project. As I state in my direct
23 testimony starting at line 25 of JCD-46, "some known scope with highly uncertain
24 costs have projected expenditures excluded from exhibits (such as the Security

Line
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1 Computer Replacement project) until such time the expenditures are capable of
2 being identified with reasonable specificity to include in the exhibit[.]”
3

4 **Q40. Does the updated Plant Radio project appropriations (page 4 of Witness**
5 **Coppola’s confidential Exhibit AG-10) request accurately describe why the**
6 **project baseline budget changed from approximately \$16 million to \$19**
7 **million?**

8 A40. Yes. Though, in the case of this updated Plant Radio project appropriation, the
9 variance narrative could have provided additional context such that it was clear that
10 “legacy issues with undersized wiring feeding the transformers of the UPS” means
11 that when DTE Electric approved the initial baseline scope, the wires powering the
12 uninterruptible power supplies (UPS) were assumed to have sufficient capacity to
13 operate safely with the UPS units required for the Plant Radios; however field
14 inspections and engineering calculations demonstrated that the wires would be
15 insufficient to support the new Plant Radio System. As I have discussed, since
16 Nuclear Generation and, in general DTE Electric, does not include contingencies
17 in its rate case projections, establishing expenditure projections to replace wiring
18 in the contingent event that the wire may not have sufficient capacity would be
19 inappropriate.
20

21 **Q41. How do you respond to Witness Coppola’s assertion in his testimony at line 19**
22 **of page 39, that these project changes represent an “excessive cost overrun” or**
23 **reflect “an imprudent and unreasonable approach to project cost**
24 **management?”**

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1 A41. I disagree. I acknowledge in my direct testimony at line 22 of JCD-46, “[t]he need
2 for and use of contingency amounts at the individual project level and at the
3 portfolio level is well understood in project management and portfolio
4 management.” However, as Witness Kindschy’s proposed reductions reinforce –
5 there is minimal grace extended to projections with potential for real world
6 uncertainty and yet, the world is an uncertain place. This paradigm leads to a
7 conclusion that projection variances in and of themselves are not evidence of
8 imprudence or unreasonable project management but rather a reasonable potential
9 outcome in some amount (higher or lower), for some project components based on
10 the case records developed by the Commission over the years.

11

12 **Q42. What are your thoughts on Witness Coppola’s questioning (line 7, page 45 of**
13 **his direct testimony) whether certain projects that you support are likely to**
14 **extend beyond the test period, yet have “annual” in-service designations are**
15 **“eligible for inclusion in rate base in this rate case?”**

16 A42. The inclusion of certain projects (Natural Draft Cooling Towers, Document
17 Management System Enhancements, Remote Monitoring) in this instant rate case
18 is fully appropriate, reasonable and prudent and represents DTE Electric’s evolving
19 Fermi 2 operations and management systems. That said project timing may move
20 should other Fermi 2 operational priorities manifest themselves through the
21 projected test period. It is fair to identify projects that have zero historical
22 expenditures and have projected expenditures only in the projected test period and
23 highlight any uncertainty in the in-service date.

24

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1 **Q43. Is complete disallowance of the projected expenditures by the Commission**
2 **appropriate for expenditures that support projects that may have their in-**
3 **service dates extend beyond the test period?**

4 A43. No. I discussed throughout my direct testimony regarding DTE Electric's nuclear
5 safety prioritization. The Commission should determine the Nuclear Generation
6 capital expenditures, in total, as presented are reasonable and prudent and are
7 consistent with Nuclear Generation's actual historical capital expenditures to safely
8 and reliably operate Fermi 2. Alternatively, an acknowledgement from the
9 Commission that the projects will be recoverable in the future once they are in-
10 service would be supportive.

11

12 **Q44. What are your thoughts concerning Witness Coppola's proposal to reduce**
13 **approximately \$24.0 million of capital expenditures for the Natural Draft**
14 **Cooling Towers, Document Management System and Remote Monitoring?**

15 A44. Witness Coppola asserts at line 11 of page 45 in his direct testimony that these
16 projects "should have identified project phases and timelines with a completion in-
17 service date" and Witness Coppola had asked for a specifically formatted project
18 status update ("i.e. needs identification, initial concept scoping, engineering design,
19 out for bids, construction, completed") in his discovery request depicted on page 2
20 of Witness Coppola's Exhibit AG-12. These phases are typically associated with a
21 phase-gate approval process. As I clarify later in my testimony, and as my discovery
22 response explains (also depicted on the same exhibit) that Nuclear Generation does
23 not use a phase-gate approval process as potentially envisioned by Witness
24 Coppola. The fact that project statuses as prescribed by Witness Coppola's

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1 discovery request are not used by Nuclear Generation does not demonstrate
2 anything whatsoever regarding reasonableness or prudence.

3

4 **Q45. Does Nuclear Generation use an “unorthodox project management approach”**
5 **as Witness Coppola suggests in his direct testimony at line 5, page 45?**

6 A45. Nuclear Generation uses nuclear work management processes to manage capital
7 projects. Witness Coppola’s assertion of “unorthodox” is unfounded as graded or
8 modified approaches to capital project management is reasonable and prudent
9 based on the scope and implementation of the capital projects. Nuclear Generation
10 does not use the phase-gate approval process potentially envisioned by Witness
11 Coppola as the majority of Nuclear Generation’s capital work is asset replacement,
12 not new construction, and though there may be a design change as I have discussed
13 in my direct testimony at line 15, page JCD-25, design change at a nuclear power
14 plant is to maintain configuration control, not to necessarily design new equipment.
15 This means that a generalized understanding of project management that may apply
16 in other fields, such as building construction, that includes steps such as (1) identify
17 problem, (2) design solution, (3) solicit material labor contracts, and (4) execute
18 work, is not necessarily applicable to an operating nuclear power plant.

19

20 For example, when a pump motor is at end of life – this pump motor must be
21 replaced because the Fermi 2 license requires the pump motor. DTE Electric
22 identifies the new pump motor (likely from the only supplier that sells such a pump
23 motor); however, the closest match to the existing pump motor is slightly different
24 in electrical draw, mechanical mounting and fitting and size and weight. DTE
25 Electric purchases the pump motor but now must perform a design change (plant

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1 modification) and update calculations to ensure the new electrical draw is
2 accounted for and the weight of the new pump motor is seismically accounted for.
3 As the design change is occurring, DTE Electric may also be performing
4 implementation tasks using its pre-approved labor suppliers.

5
6 A rigid adherence to a phase-gate approval process would result in decision-making
7 paralysis because the new pump motor must be purchased well before the design
8 would ever be completed. It is this dynamic that leads Nuclear Generation to
9 sometimes use a “partial” appropriation and then follow-up with a “full”
10 appropriation to allow solicitation, procurement, design and implementation
11 planning to all occur simultaneously at the initial stages, then as this initial work
12 progresses, the full amount of the project becomes clearer and the full appropriation
13 can be reasonably authorized. This approach is necessary, reasonable, and prudent.

14

15 **Q46. Does a project such as the Natural Draft Cooling Tower follow project**
16 **management principles?**

17 A46. Not in the manner potentially envisioned by Witness Coppola. Natural Draft
18 Cooling Towers is not a “project” in industry terms, it is a “capital maintenance
19 activity.” There are no “project phase” activities – for example, engineering is not
20 required because the assets being replaced are, in industry terms “like-for-like” and
21 thus the replacements of retirement units do not drive modification to the plant
22 when executed. As I state in my direct testimony, our suppliers have been pre-
23 selected and on-site therefore solicitation is not specific to this project. This exact
24 type of capital replacement has been performed in years past as the material

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1 condition of the cooling towers has warranted and work planning is relatively
2 straight forward.

3

4 **Q47. Would a project such as Remote Monitoring follow project management**
5 **principles?**

6 A47. Similar to the Natural Draft Cooling Tower, not in the manner potentially
7 envisioned by Witness Coppola. Remote Monitoring is not a “project” in industry
8 terms, but rather it is a “capital maintenance activity.” As I depict on page 28 of
9 Exhibit A-20, Schedule J2, the scope is the installation of equipment monitoring
10 devices. DTE Electric projects that with the completion of Plant Wireless,
11 engineering design requirements will be minimal for the 2025 scope. Though the
12 project is projected to be completed in 2026, the “annual” designation for in-service
13 is consistent with DTE Electric’s intent to place into service in 2025 those remote
14 monitoring assets installed in 2025, and then complete the initial remote monitoring
15 installation in 2026 and place the remaining balance of the assets in service then.

16

17 **Q48. Would a project such as the Document Management System follow project**
18 **management principles?**

19 A48. Not in the manner potentially envisioned by Witness Coppola. The Document
20 Management System is the purchase and addition of modules to Fermi 2’s existing
21 document management system. DTE Electric does not project plant modifications
22 or additional solicitations as the document management system is already in-use at
23 Fermi 2. For this rate case, DTE Electric projected modules for activities such as
24 automated workflow of design documents to be installed and in-service in 2025,

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1 with other modules such as paperless procedures projected to be in-service in 2026
2 – hence the “annual” designation for the in-service date.

3

4 **Q49. What are your thoughts concerning Witness Coppola’s proposal to reduce**
5 **approximately \$6.4 million of capital expenditures for the Sanitary System**
6 **project?**

7 A49. Witness Coppola asserts at line 4 of page 46 in his direct testimony that these
8 projects “should have a project plan and timeline with a stated completion date and
9 in-service date.” Also, Witness Coppola suggests at line 5 of page 46 of his direct
10 testimony: “The “Annual” in-service date designation by the Company would
11 imply an annual program, which does not appear to be correct for this project.” The
12 Sanitary system replacement project is intended to initiate and complete installation
13 of the two-pump system in 2025, where the “annual” designation is used to convey
14 that individual assets associated with the annual expenditures (in this case the two-
15 pump system noted in my direct testimony) will be in-service prior to year’s end
16 (in this case in-service in 2025). Additional expenditures to replace or reroute
17 additional portions of the sanitary system may be required – though not known at
18 this time, for this reason, my direct testimony explains project expenditures “extend
19 beyond the projected test period.”

20

21 **Q50. Does DTE Electric have any “inability or unwillingness to provide a project**
22 **timeline and current phase of development,” as Witness Coppola suggests on**
23 **page 46 of his direct testimony at line 7?**

24 A50. No. Witness Coppola had asked for a specifically formatted project status update
25 (“i.e. needs identification, initial concept scoping, engineering design, out for bids,

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1 construction, completed”) in his discovery request depicted on page 2 of Witness
2 Coppola’s Exhibit AG-12. As my discovery response explained (also depicted on
3 the same exhibit) and as I have described above, Nuclear Generation does not status
4 projects as a particular phase or in the manner requested. The sanitary sewer
5 program has no projected spend in 2024 and no historical actual spend. In non-
6 specific terms, this means the sanitary sewer project has not started and is not
7 projected to start until 2025. DTE Electric is reasonable and prudent to include the
8 Sanitary system replacement projected expenditures and there is no basis to
9 disallow the \$6.4 million of capital expenditures for the Sanitary System project
10 proposed by Witness Coppola and the Commission should not adopt Witness
11 Coppola’s proposed reduction.

12

13 **Q51. What are your thoughts concerning Witness Coppola’s proposal to reduce**
14 **approximately \$20.0 million of capital expenditures for Nuclear Fuel?**

15 A51. Nuclear Generation’s nuclear fuel expenditures are reasonable and prudent.
16 Witness Coppola’s proposal to reduce Nuclear Fuel expenditures is not reasonable
17 and not prudent and based on an incorrect inference from my discovery response
18 depicted on page 3 of Witness Coppola’s Exhibit AG-11 as well as a
19 misunderstanding about nuclear fuel projections provided in previous rate cases.

20

21 **Q52. Witness Coppola asserts on line 2, page 44 of his direct testimony at line 5 “the**
22 **Company discusses variances in the number of fuel assemblies from outage to**
23 **outage without addressing specifically the cost variance between 2023 and**
24 **2025.” Does purchasing more nuclear fuel assemblies address variance in cost**
25 **expenditures?**

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1 A52. I believe it does. Page 3 of Witness Coppola's Exhibit AG-11 shows Nuclear
2 Generation projects to purchase uranium, enrichment, and fabrication to support
3 244 nuclear fuel assemblies in 2025 for introduction into the Fermi 2 reactor core
4 in RF23 (2026); whereas Nuclear Generation only purchased uranium, enrichment
5 and fabrication to support 220 nuclear fuel assemblies in 2023 for introduction into
6 the Fermi 2 reactor core in RF22 (2024). All other factors being equal, 244 nuclear
7 fuel assemblies will have approximately 11% more total cost than 220 nuclear fuel
8 assemblies.

9

10 **Q53. Do you agree with Witness Coppola's assertion at line 7 on page 43 of his direct**
11 **testimony that DTE Electric's "calculation is in accordance with industry**
12 **accepted software and rules, without providing further explanation or support**
13 **for the calculation"?**

14 A53. No. In addition to the change in the number of nuclear fuel assemblies discussed
15 above, Page 3 of Witness Coppola's Exhibit AG-11 a discovery response from the
16 Company states that nuclear fuel expense is, in part, "an outcome of a reasonable
17 and prudent analysis of the nuclear fuel cycle components and *contract terms*
18 *applied* to the projected Fermi 2 nuclear core design requirements, consistent with
19 the Company's 2024 PSCR Plan U-21425." (emphasis added). In support of the
20 Company's 2024 PSCR Plan Case No. U-21425, DTE Electric Witness Wines
21 discussed how nuclear fuel projections are developed including use of relevant
22 electricity generation plans, nuclear fuel bundle loading quantities and nuclear fuel
23 cycle component prices; Witness Wines also discussed the status of DTE Electric's
24 nuclear fuel cycle contracts. The Company's 2024 PSCR Plan and 5-year forecast

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1 have been approved in Case No. U-21425 by the Commission's Order dated July
2 23, 2024.

3

4 **Q54. Witness Coppola asserts at line 1, page 44 of his direct testimony that DTE**
5 **Electric “has a propensity to overestimate the cost of nuclear fuel.” What are**
6 **your thoughts concerning Witness Coppola’s historical analysis of DTE**
7 **Electric’s nuclear fuel costs?**

8 A54. I will first introduce Exhibit A-47, Schedule LL2 Nuclear Fuel Expenditures.
9 Column (a) of Exhibit A-47, Schedule LL2 are recent DTE Electric rate cases,
10 column (b) describes the expenditure, in this instance total nuclear fuel, columns
11 (c) through (j) depict the level of total nuclear fuel expenditure DTE Electric
12 provided in the rate case (exhibits and associated workpapers) listed in column (a),
13 and I denote with an “A” those expenditure amounts depicted were actual historical
14 amounts and not projected. Column (k) is the sum of the projected nuclear fuel
15 expenditures for the rate case list in column (a) and column (l) is the sum of the
16 total historical actual expenditures for the same projection period (note: 2024 is not
17 complete and uses the projected amount) and used in column (k), such that
18 comparing columns (k) and (l) is valid.

19

20 Exhibit A-47, Schedule LL2 demonstrates that DTE Electric has historically
21 provided reasonable and prudent nuclear fuel expenditure projections. For example,
22 Witness Coppola himself highlights that the nuclear fuel projection in DTE Electric
23 rate Case No. U-20836 for 2021 nuclear fuel expenditures was approximately
24 \$122.7 million with actual nuclear fuel expenditures being \$120.1 million (line 14
25 on page 43 of direct testimony) or within 2%; DTE Electric’s projected 2023

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1 nuclear fuel expenditures for 2023 in Case No. U-20836 were \$111.0 million with
2 actual nuclear fuel expenditures being \$110.1 million or within 1%. As I depict at
3 line 9, column (k) of Exhibit A-47, Schedule LL2, the total projected nuclear fuel
4 expenditures provided in Case No. U-20836 (Calendar years 2021, 2022 and 2023)
5 were \$233.9 million with actual total nuclear fuel expenditures for the same period
6 at \$233.4 million.

7

8 **Q55. Witness Coppola converts the \$117.4 million total nuclear fuel expenditures**
9 **projected for 2023 in DTE Electric Case No. U-21297 to \$128.1 million by**
10 **asserting “the Company forecasted \$117,421,000 for 11 months of costs for**
11 **nuclear fuel which annualized means it had forecasted \$128,100,000 for the**
12 **entire year” at line 16 of page 43 of his direct testimony. Did DTE Electric**
13 **project approximately \$128.1 million for nuclear fuel expenditures for the 12-**
14 **months ending December 31, 2023, in DTE Electric rate Case No. U-21297?**

15 **A55. No. In DTE Electric rate Case No. U-21297, DTE Electric projected \$117.4 million**
16 **for the 12-month period ending December 31, 2023. Witness Coppola is correct in**
17 **his recollection that the DTE Electric rate Case No. U-21297 did use a bridge period**
18 **that included the 11 months ending November 30, 2023, but Case No. U-21297**
19 **also included the subsequent 12-month period ending November 30, 2024, as the**
20 **projected test period which only projected \$0.2 million of nuclear fuel expenditures.**
21 **DTE Electric’s total projected nuclear fuel costs for the 23-month period ending**
22 **November 30, 2024, was only approximately \$117.6 million, not \$128.1 million as**
23 **Witness Coppola mistakenly asserts.**

24

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1 **Q56. How do the total nuclear fuel expenditures depicted at line 10, page 1 of**
2 **Exhibit A-12, Schedule B5.3 (Case No. U-21534) compare to the total nuclear**
3 **fuel expenditures depicted at line 10, page 1 of Exhibit A-12, Schedule B5.3**
4 **(Case No. U-21297) then for the period ending November 30, 2024?**

5 A56. DTE Electric's total nuclear fuel expenditures depicted in Exhibit A-12, Schedule
6 B5.3 (U-21534) for the 23-month period ending November 30, 2024, is \$112.0
7 million. As I depict in Exhibit A-47, Schedule LL2 at line 10, column (k), the
8 previous rate case (Case No. U-21297) total nuclear fuel expenditures for the same
9 23-month period ending November 30, 2024, was \$117.7 million. The variance
10 between the two rate cases is approximately 4%.

11

12 **Q57. In DTE Electric's rate Case No. U-20162, DTE Electric projected total nuclear**
13 **fuel expenditures for 2018 and 2019. How did the historical actual**
14 **expenditures compare?**

15 A57. Recall, these expenditures support an 18-month fuel cycle. As I depict in Exhibit
16 A-47, Schedule LL2, at line 7, column (k,) DTE Electric's Case No. U-20162 total
17 nuclear fuel expenditure projections totaled \$152.0 million for the calendar years
18 2018 and 2019 and had historical actuals of \$150.5 million (depicted at line 7,
19 column (l)). The net variance between the U-20162 total nuclear fuel expenditure
20 projections and actual total nuclear fuel expenditures were less than 1%.

21

22 **Q58. In DTE Electric's rate Case No. U-20561, DTE Electric projected total nuclear**
23 **fuel expenditures for 2019 through 2021. How did the historical actual**
24 **expenditures compare?**

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1 A58. Recall, these expenditures support an 18-month fuel cycle. As I depict in Exhibit
2 A-47, Schedule LL2, at line 8, in DTE Electric rate Case No. U-20561, DTE
3 Electric projected \$83.5 million, \$0.1 million and \$114.4 million of nuclear fuel
4 expense for calendar years 2019, 2020 and 2021 respectively for a total projected
5 nuclear fuel expenditures total of \$198.0 million as depicted at line 8, column (k).
6 DTE Electric had actuals of \$78.0 million, \$0.3 million and \$120.1 million of
7 nuclear fuel expense for calendar years 2019, 2020 and 2021 respectively for a total
8 actual nuclear fuel expenditures total of \$198.4 million depicted at line 8, column
9 (l). The net variance between the three years is less than 0.5%.

10

11 **Q59. What do you conclude from your analysis of DTE Electric's historical**
12 **projections for nuclear fuel expenditures?**

13 A59. DTE Electric's nuclear fuel expenditure projections are reasonable and prudent.
14 Variances to the historical nuclear fuel expenditures have been immaterial and there
15 is a historical basis to be confident that DTE Electric's projected nuclear fuel
16 expenditures are accurate and very likely to be incurred as projected.

17

18 **Q60. Witness Coppola points to historical nuclear fuel expenditures of \$120.1**
19 **million in 2021 and \$110.0 million in calendar years 2021 and 2023 respectively**
20 **to assert that the average nuclear fuel expenditure of \$115.1 million is the**
21 **reasonable and prudent amount of 2025 expenditure for Fermi 2's nuclear fuel**
22 **(at line 10, page 43 of his direct testimony). Is Witness Coppola's analysis**
23 **consistent with how nuclear fuel projections are formulated?**

24 A60. No. The operational history of Fermi 2 renders this type of analysis invalid. Reactor
25 core design and nuclear fuel projections are not straightforward calculations but

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1 rather are dependent on the operational history of the reactor. The analysis of how
2 many nuclear fuel assemblies to replace each refueling outage requires specialized
3 education, training, and specific regulatory-approved software.

4
5 To help simplify the discussion – Nuclear fuel must be loaded into the reactor core
6 to sustain electricity generation operations through to the next refueling outage
7 where it's a given that the longer the time between the end of one refueling outage
8 and the start of the next refueling outage, the more nuclear fuel must be consumed
9 to sustain that operating cycle. Because Fermi 2 Refueling Outage 20 (RF20) had
10 a duration of approximately 138 days, and RF21 had a duration of approximately
11 98 days, DTE Electric was able to replace fewer nuclear fuel assemblies than the
12 equilibrium amount of 240 nuclear fuel assemblies to sustain the 2022 – 2024
13 operating cycle, where equilibrium amount means the number of nuclear fuel
14 assemblies calculated to be replaced every refueling outage assuming the reactor is
15 operated repeatedly to the same cycle plan. The planned RF22 duration was near
16 the equilibrium assumption of 45 days, which results in DTE Electric not only
17 replacing the equilibrium number of 240 nuclear fuel assemblies but also
18 incremental nuclear fuel assemblies to account for the nuclear fuel assemblies DTE
19 Electric did not have to replace in prior refueling outages.

20

21 **Q61. What is your recommendation to the Commission regarding Witness**
22 **Coppola's proposed reduction of approximately \$20.0 million for nuclear fuel**
23 **expenditures?**

24 A61. I recommend the Commission not adopt Witness Coppola's proposal to reduce
25 nuclear fuel expenditures by \$20.0 million. DTE Electric demonstrates that nuclear

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1 fuel expenditure projections are reasonable and prudent given the approved
2 methodology for the projected number of fuel assemblies. DTE Electric also
3 demonstrates the change in the projected number of fuel assemblies relative to past
4 operational cycles is reasonable and prudent given Fermi 2's operational history,
5 and DTE Electric has demonstrated its past nuclear fuel projections have been
6 reasonable, prudent, and accurate.

7

8 **Q62. Does this conclude your rebuttal testimony?**

9 A62. Yes, it does.

1 JUDGE WALLACE: All right. Go ahead,
2 Mr. Christinidis.

3 MR. CHRISTINIDIS: Thank you, your Honor.
4 Your Honor, the Company's next witness is Pina Bennett.
5 Ms. Bennett sponsored the Qualifications and Direct
6 Testimony of Pina Bennett, consisting of a cover sheet
7 and 71 pages of questions and answers. She also filed
8 Rebuttal Testimony of Pina Bennett, consisting of a cover
9 sheet and 29 pages of questions and answers. She
10 sponsors five direct exhibits and schedules: Those
11 direct exhibits and schedules are Exhibit A-12 Schedule
12 B5.9; Exhibit A-13 Schedule C5.7.1, Exhibit A-13 Schedule
13 C5.9, Exhibit A-13 Schedule C5.9.2, and Exhibit A-29
14 Schedule T1. She also sponsors five rebuttal exhibits
15 and schedules, which are designated as Exhibit A-49
16 Schedules NN1 through NN5. So with that, your Honor, the
17 Company would move to bind into the record the
18 Qualifications, Direct Testimony, and Rebuttal Testimony
19 of Pina Bennett, and move the admission of the
20 aforementioned exhibits and schedules.

21 JUDGE WALLACE: Is there any objection to
22 binding in the direct and rebuttal testimony of
23 Ms. Bennett?

24 Hearing none, the testimony is bound in.

25 Is there any objection to any of the
Penn Reporting, LLC - lori.penn@yahoo.com

1 exhibits an or associated schedules listed by
2 Mr. Christinidis, sponsored by Ms. Bennett? (No
3 response.)

4 (Testimony bound in.)

5 - - -

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
DIRECT TESTIMONY
OF
PINA BENNETT

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF PINA BENNETT

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

2 A1. My name is Pina Bennett (she/her/hers). My business address is: One Energy Plaza,
3 Detroit, Michigan 48226. I am employed by DTE Electric Company (“DTE
4 Electric” or “Company”).

5

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

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

8

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

10 A3. I graduated from Gujarat University (India) with a Bachelor of Science Degree in
11 Electronics. In addition, I received a master’s degree in business administration
12 from Gujarat University in India. I have also completed several Company-
13 sponsored courses and attended various seminars and conferences to further my
14 professional development.

15

16 **Q4. Do you have any professional certifications or other certifications?**

17 A4. Yes, I also hold a Lean Six Sigma Black Belt certification.

18

19 **Q5. Please summarize your professional experience.**

20 A5. I began my career in India on the product management team at Torrel Cosmetics, a
21 division of Torrent Pharmaceuticals, where I was responsible for launching a range
22 of eleven skincare products. I worked in the business-to-business marketing
23 industry in Singapore and was a professor at S. K. Patel Institute of Management
24 & Computer Studies, teaching master’s level marketing courses. While there, I
25 developed an executive marketing training program for corporate executives. I

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1 joined DTE Electric in 2008 as the program owner for the Outdoor Protective
2 Lighting program, in the Community Lighting organization, which was part of the
3 DTE Electric Regulated Marketing organization. Between 2010 and 2018, I held a
4 number of Chief of Staff positions across DTE Electric and DTE Energy Corporate
5 Services (LLC). These positions had varying titles and supported the Vice President
6 of Marketing, Vice President of Distribution Operations, Senior Vice President of
7 Distribution Operations, Chief Administrative Officer, and Chief Nuclear Officer.
8 In these roles, I was responsible for providing strategic oversight and organizational
9 accountability for business success. I then became the Manager of Joint Use
10 Operations within DTE Electric Sales and Marketing. In this role, I was responsible
11 for managing third-party attachments to DTE Electric-owned assets. In November
12 2022, I started my current role as Director of Electric Marketing in the Electric
13 Sales and Marketing organization of DTE Electric.

14

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

16 A6. My responsibilities as Director of Electric Marketing span three primary focus
17 areas:

- 18 1. Transportation Electrification: support and accelerate EV adoption within DTE
19 Electric's service territory and help the State of Michigan achieve its
20 decarbonization goals;
- 21 2. New Product Development: assess and provide products and services, which
22 support customer satisfaction and customer affordability, under the Value-
23 Added Programs and Services ("VAPS") regulations;

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- 1 3. Customer Marketing: communicate with customers regarding DTE Electric
- 2 rates and tariffs for electric service and address customer inquiries or
- 3 complaints.

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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to explain and support the programs, policies, and
4 Company departments, along with any associated costs, for the five following
5 areas:

- 6 1. Status of existing Charging Forward program components;
- 7 2. The Company's proposal for a Transportation Electrification Plan ("TEP");
- 8 3. Customer Collection – Merchant Fee expense;
- 9 4. Certain expenditures related to the 2023 full time-of-day ("TOD") roll out; and,
- 10 5. Electric Regulated Marketing operations and maintenance ("O&M") expense.

11

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

13 A8. Yes. I am sponsoring the following exhibits:

14 Exhibit	Schedule	Description
15 A-12	B5.9	Charging Forward Cost Projections
16 A-13	C5.7.1	Customer Service– Credit/Debit Card Merchant Fees
17 A-13	C5.9	Regulated Marketing Projected O&M Expenses
18 A-13	C5.9.2	TOD Regulatory Asset Deferral
19 A-29	T1	Charging Forward 4 th Annual Status Report

20

21 **Q9. Were these exhibits prepared by you or under your direction?**

22 A9. Exhibit A-29, Schedule T1 was prepared under my direction pursuant to the Orders
23 dated May 2, 2019 and May 8, 2020 in Case Nos. U-20162 and U-20561,
24 respectively. Exhibit A-13, Schedule C5.9.2 is co-sponsored with Company

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1 Witnesses Hatsios and Sparks. The remaining exhibits were prepared under my
2 direction in support of the instant case.

3

4 **1. Status of Existing Charging Forward Program Components**

5 **Q10. What is the status of the pilots in the existing Charging Forward program?**

6 A10. In May 2019, the Commission issued an Order in Case No. U-20162 approving the
7 original Charging Forward and funding was exhausted by year-end 2023. Building
8 on the momentum of the fleet element in the original Charging Forward program,
9 the Company proposed Charging Forward eFleets (“eFleets”) in Case No. U-20935
10 in December 2020 and received approval in March 2021. The third iteration of
11 funding for the Charging Forward Expansion (“Expansion”) was approved in
12 November 2022 in Case No. U-20836. Most recently, in December 2023, the
13 Michigan Public Service Commission (“MPSC”) approved funding in Case No. U-
14 21297 to continue Charging Forward programming through 2024.

15

16 **Q11. What elements of Charging Forward programming are categorized as**
17 **permanent programs or pilots?**

18 A11. The Charging Forward programming elements are categorized as follows:

- 19 • Permanent program offerings¹: Education & Outreach, Emerging
20 Technology Fund, and Program Administration;
- 21 • Pilot offerings: Home Charger Rebates, Home Charger Install, EV Rebates,
22 Business Charger Rebates, Business Charger Installation, eFleet Charger
23 Rebate, eFleet Battery Support, School Bus Chargers and Charging Hubs.

24

¹ As approved annually through 2028 with the December 1, 2023 Order in Case No. U-21297

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1 **Q12. What is the Company's total expected investment for the existing Charging**
2 **Forward program?**

3 A12. The total actual and estimated future investments for the existing Charging Forward
4 program, through the end of 2024, are summarized in Table 1 below.

5

6 **Table 1 Actual & Estimated Program Investment (in \$ thousands) by**
7 **Element²**

8

Program Element	2019	2020	2021	2022	2023	2024	Total
Program	273	448	648	965	1,610	1,813	5,757
Administration							
Education & Outreach	382	202	365	1,216	1,036	1,800	5,001
Business and eFleet	162	511	1,858	2,599	2,927	11,996	20,054
Charger Rebates							
Home Charger					520		520
Installation							
Business Charger Installation						3,315	3,315
Charging Hubs					96	1,800	1,896
eFleet Battery Support						5,000	5,000
School Bus Chargers						2,000	2,000
Residential Customer	48	121	290	655	1,828	2,000	4,941
Rebates ³							
Additional Elements	227	119	112	564			1,022
Emerging Tech Fund					825	1,000	1,825
Total	1,092	1,401	3,273	6,000	8,842	30,724	51,332

9

10 The capital, O&M, and regulatory asset treatment of the above investment is shown
11 in Table 2 below.

² Differences in totals due to rounding

³ Residential Customer Rebates include Home Charger Rebates and EV Rebates

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1 **Table 2 Actual & Estimated Program Investment (in thousands) by Type⁴**

2

Spend Type	2019	2020	2021	2022	2023	2024	Total
Capital	64		196	15	994	12,509	13,778
O&M					922	2,293	3,214
Regulatory Asset	1,028	1,401	3,078	5,985	6,927	15,922	34,341
Total	1,092	1,401	3,274	6,000	8,842	30,724	51,332

3 Exhibit A-12, Schedule B5.9 shows the total estimated calendar year investment
4 (lines 1 through 24) for the following periods:

- 5 ▪ January, 1 2022 to December 31, 2022 (“historical period”) in column (b);
6 ▪ January 1, 2023 to December 31, 2024 (“bridge period”) in column (e); and
7 ▪ Total actual and estimated pilot and permanent program costs for the
8 historical and bridge periods are \$6,000 thousand and \$39,566 thousand,
9 respectively, as shown in line 24.

10

11 **Q13. What are the costs included in Program Administration?**

12 A13. The December 1, 2023 Order in Case No. U-21297 approved \$1.8M in annual
13 O&M costs for Expansion Program Administration. The December 1, 2023 Order
14 in Case No. U-21297 also continued regulatory asset treatment for approximately
15 an average of \$0.8 million in annual costs through the projected test year for eFleet
16 Advisory Services, which was originally approved in Case No. U-20935.⁵ The
17 combined Program Administration investment enabled common elements for all
18 permanent programs and pilots approved in the Charging Forward program, to be
19 managed by a single budget and administrative team. The Company is in the
20 process of ramping up a 14-person team to accomplish the objectives addressed in
21 Case No. U-21297. The administrative team, currently at ten Full Time Employees

⁴ Differences in totals due to rounding

⁵ This approved plan for eFleet Advisory services spans the calendar years 2021 through 2025.

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1 (FTEs), allocates 40% of its resources to eFleets (regulatory asset), 15% (capital)
2 to reflect the work on capital projects, and 45% (O&M) on all other initiatives. By
3 2025, all Program Administrative spend will move to O&M. These expenditures
4 are shown in lines 2, 12 and 15 of Exhibit A-12, Schedule B5.9 with actual
5 investments of \$1.0 million and \$3.4 million for the historical and bridge periods
6 in columns (b) and (e), respectively.

7

8 **Q14. What are the costs for Education and Outreach (E&O)?**

9 A14. There are no modifications to the Company's combined E&O budget for the
10 Charging Forward program, as proposed and approved with the December 1, 2023
11 Order in Case No. U-21297, at a total of \$1.5 million annually in O&M and \$0.3
12 million in regulatory assets for eFleets. Lines 11 and 16 of Exhibit A-12, Schedule
13 B5.9, shows the actual investment of \$1.2 million for the historical period in
14 column (b) and \$2.8 million for the bridge period in column (e).

15

16 **Q15. What are the costs for Business and eFleet Charger Rebates?**

17 A15. The Company was approved a total of \$24.4 million, with the December 1, 2023
18 Order in Case No. U-21297, for Business and eFleet Charger Rebates. This total
19 includes \$5.8 million to exhaust funding of the original Charging Forward pilot
20 through 2023, \$6.9 million for eFleets Business Charger Rebates through 2024, and
21 \$11.7 million for Expansion's Business Charger Rebates through 2024. The
22 Company incurred decreased levels of approved and installed DCFC sites after
23 implementing additional requirements⁶ as ordered by the Commission that aligned

⁶ DTEE site requirements and preferred site conditions for DCFC sites are available at
<https://www.dteenergy.com/content/dam/dteenergy/deg/website/business/service-and-price/pev/plug-in-electric-vehicles-pev/DCFCSiteRequirements.pdf>

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1 with the National Electric Vehicle Infrastructure (NEVI) projects. Furthermore,
2 the Company's capital costs for public commercial DC fast chargers (DCFCs)
3 turned out to be lower than initially projected. The conservative approach taken
4 during the pilot phase contributed to this outcome and we intend to deploy these
5 funds in 2024 to support projects that have well-justified use cases to ensure prudent
6 investment. The eFleet project installations, tied to recipients of the Environmental
7 Protection Agency's Clean School Bus Rebate Program, were also more
8 conservative in terms of spend and timing. As a result of these insights, the
9 Company reduced the total budget for this component by approximately \$10
10 million. Added together, lines 3 and 18 of Exhibit A-12, Schedule B5.9, show the
11 actual and projected investment of \$2.6 million for the historical period and \$14.9
12 million for the bridge period in column (b) and (e) respectively. We intend to deploy
13 these funds in 2024 to support projects that are well-justified use cases to ensure
14 prudent investment.

15

16 **Q16. What are the costs for Home Charger Installation?**

17 A16. The Company was approved \$2.3 million, with the November 2022 Order in Case
18 No. U-20836, for Home Charger Installation. The pilot commenced in early 2023
19 and by the end of 2023, had provided turnkey charger installation solutions for over
20 600 residential customers and approved over 40 installations scheduled to be
21 completed in 2024, reducing financial and physical installation barriers to home
22 charger ownership and EVs.

23

24 With the initial set up of the pilot for financing home EV charger installations, there
25 was an overestimation of the capital expenditures required for the program. While

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1 the Company incurred upfront costs of \$2.4 million to purchase and install the
2 chargers and develop the necessary IT systems to set up and support the program,
3 the appropriate accounting treatment is to record \$1.9 million of these expenses as
4 Receivables from customers. Instead of recovering the Receivables through base
5 rates, the Company recovers those costs through a fee added to participating
6 customers' bills. Thus the \$1.9 million Receivable is not proposed to be included
7 as part of the Company's base rate request in the instant case and is not included in
8 Exhibit A-12, Schedule B5.9, Line 4, column (e). The remaining \$0.5M of capital
9 expenditure covers IT and program setup costs.

10

11 Additionally, around mid-year 2023, the Company received intervenor feedback on
12 transitioning the pilot to value-added programs and services ("VAPS"), which also
13 resulted in scaling back the investment as a regulated offering. With the recent
14 December 1, 2023, Order for Case No. U-21297, the Home Charger Installation
15 pilot has been terminated and the Company anticipates transitioning it to VAPS in
16 2024. Line 4 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b)
17 and bridge period costs of \$0.5 million in column (e).

18

19 **Q17. What are the costs for Business Charger Installation?**

20 A17. The Company was approved \$3.5⁷ million with the December 1, 2023 Order in
21 Case No. U-21297 for Business Charger Installation. Lines 5 and 19 of Exhibit A-
22 12, Schedule B5.9 show zero actual costs in column (b) and \$3.3 million for bridge
23 period costs in column (e).

24

⁷ Total of \$1.2 million for bridge period (\$0.5 million capital and \$0.7 million regulatory asset) and a total \$2.3 million for test period (\$1.0 million capital and approximately \$1.3 million regulatory asset)

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1 **Q18. What is the status of the Business Charger Installation program?**

2 A18. Originally, the Company was meant to own the chargers. Instead, the pilot was
3 modified to have the site hosts take ownership, while DTE Electric provides full
4 support for utility infrastructure, customer readiness, and charger expenses. The
5 Company intends to deploy the bridge period funding in 2024.

6

7 **Q19. What are the costs for Charging Hubs?**

8 A19. The Company was approved \$2.8 million, with the November 2022 Order in Case
9 No. U-20836, and \$2.7 million, with the December 2023 Order in Case No. U-
10 21297, for Charging Hubs. Line 6 of Exhibit A-12, Schedule B5.9 shows zero
11 actual costs in column (b), \$1.9 million for bridge period costs in column (e) and
12 \$3.5 million for the projected test period costs in column (f).

13

14 **Q20. What is the status for the Charging Hubs pilot?**

15 A20. DTE Electric was approved to begin construction on up to two Charging Hubs
16 designed for medium- and heavy-duty fleet vehicles providing multiple fast
17 chargers in a single location. The Company is collaborating with federal grant
18 partners, such as the State of Michigan, and Detroit Diesel (Daimler Truck North
19 America) to fulfill grant requirements for the Department of Transportation's
20 Rebuilding American Infrastructure with Sustainability and Equity, or "RAISE"
21 program that awarded \$8.5M of funding for the buildout of the first Charging Hub
22 in Redford. The Company is focused on executing key activities in the bridge and
23 test period which include defining roles and establishing partnership agreements,
24 finalizing the scope of work through cross-coordination with partners, launching
25 an RFP for the start of site design and engineering in 2024, and start of construction

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1 in 2025. Furthermore, the Company is scouting additional prospective sites to start
2 construction in 2025 while also looking for available federal and state grant
3 opportunities to maximize awards to the Southeast Michigan region in which DTE
4 Electric serves.

5

6 **Q21. What are the costs for eFleet Battery Support?**

7 A21. The Company was approved \$2.0 million, with the November 2022 Order in Case
8 No. U-20836, and \$3.0 million, with the December 1, 2023 Order in Case No. U-
9 21297, for eFleet Battery Support. Line 7 of Exhibit A-12, Schedule B5.9 shows
10 zero actual costs in column (b) and \$5.0 million for bridge period costs in column
11 (e). The Company intends to continue to seek partners, in 2024, in support of the
12 program.

13

14 **Q22. What are the costs for School Bus Chargers?**

15 A22. The Company received approval for \$2.0 million with the December 1, 2023 Order
16 in Case No. U-21297. Line 22 of Exhibit A-12, Schedule B5.9 shows zero actual
17 costs in column (b) and \$2.0 million for bridge period costs in column (e). Since
18 approval in December 2023, the Company has been working to establish the
19 program and intends to deploy the funding in 2024.

20

21 **Q23. What are the costs for Residential Customer Rebates?**

22 A23. Residential Customer Rebates include Home Charger Rebates and EV Rebates. The
23 Company received approval for \$2.0 million with the November 2022 Order in
24 Case No. U-20836, proposed \$1.0 million for Home Charger Rebates and \$1.0
25 million for EV Rebates in Case No. U-21297 and was approved a total of \$2.0

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1 million for both Residential Customer Rebates pilots. Line 17 of Exhibit A-12,
2 Schedule B5.9 shows the actual investment of \$0.7 million in column (b) and bridge
3 period costs of \$3.8 million in column (e).

4

5 **Q24. What are the costs included in Additional Elements?**

6 A24. In the November 2022 Order for Case No. U-20836, the Company was approved
7 to exhaust the remaining funding for the \$0.6 million budget as part of the expanded
8 scope of Charging Forward based on stakeholder feedback⁸. The funding for the
9 three Additional Elements supported costs for an EV-Grid Impact Study, an EV-
10 Ready Builder Rebate Pilot (as proposed in Case No. U-20561), and an EV-Only
11 Off-Peak Incentive Pilot (“Bring Your Own Charger”). Line 20 of Exhibit A-12,
12 Schedule B5.9 shows the actual costs of \$0.6 million in column (b) and zero bridge
13 period costs in column (e).

14

15 **Q25. What are the costs for the Emerging Technology Fund?**

16 A25. The Emerging Technology Fund was approved for \$0.9 million in Case No. U-
17 20836, and \$1.0 million annually for five years (through year 2028) with Case No.
18 U-21297. Line 21 of Exhibit A-12, Schedule B5.9 shows zero actual costs in
19 column (b) and \$1.8 million in bridge period costs in column (e).

20

21 **2. The Company’s Proposal for a Transportation Electrification Plan (TEP)**

22 **Q26. What is the purpose of this section?**

23 A26. In Case No. U-20836, the MPSC requested DTE Electric “to prepare and submit,
24 with its next rate case, a full scale, well-developed, permanent Charging Forward

⁸ Detailed further in the 3rd Annual Status Report (Exhibit A-29, Schedule T1) available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000038iECAAY>

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1 proposal that includes a BCA [benefit-cost analysis].” As a result, the Company has
2 spent the last year and a half developing a comprehensive TEP with robust analyses
3 and careful evaluation of the role of the utility along with in-depth benchmarking
4 and stakeholder consultation. The purpose of this section is to discuss the full TEP
5 portfolio – approach, programs, and benefit-cost analysis – and seek approval of
6 the expense for administering the TEP in 2025.

7

8 **Q27. How is this portion of your testimony structured?**

9 A27. This portion of my testimony is organized into the following four sub-sections:

10 I. Background and Approach

11 II. TEP Portfolio Proposal

12 III. TEP Benefit Cost Analysis

13 IV. TEP Investment

14

15 I. Background and Approach

16 **Q28. What is DTE Electric’s overall vision for its TEP?**

17 A28. DTE Electric’s goal is to power and enable a cleaner energy future for its customers
18 through transportation electrification. The Company aims to do this in a series of
19 ways:

- 20 ■ create a plan that enhances the state’s charging network and provides
- 21 customers beneficial electric pricing options along with education and
- 22 advisory services to help accelerate customers’ journeys to Electric Vehicle
- 23 (“EV”) adoption,
- 24 ■ amplify EV benefits for all customers and intentionally break down barriers
- 25 for low- and moderate-income customers and disadvantaged communities,

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- 1 ▪ integrate EV load with the grid of the future by using advanced technologies
- 2 to reduce peak demand and minimize costs to all customers, and
- 3 ▪ deliver reliable, cleaner energy to power EVs and reduce state-wide carbon
- 4 emissions.

5

6 **Q29. What are the Company’s guiding principles used to develop the TEP?**

7 A29. DTE Electric adhered to the following guiding principles in the development of the

8 TEP:

- 9 ▪ Support and accelerate EV adoption by facilitating charger deployment
- 10 while ensuring that the portfolio maintains affordability benefits for all DTE
- 11 Electric customers,
- 12 ▪ Consider unique reasons for utility participation such as closing charging
- 13 gaps and improving economics of electrification in the near-term, and
- 14 ▪ Promote equity by focusing on low-income (“LI”) customers and
- 15 disadvantaged communities (“DACs”).

16

17 **Q30. What was the Company’s approach to developing the TEP?**

18 A30. The Company spent the last 15 months developing a comprehensive TEP by:

- 19 1. Conducting in-depth benchmarking,
- 20 2. Evaluating likely service requirements, including the number of chargers,
- 21 charging infrastructure needed, and investment required,
- 22 3. Creating a framework to guide utility investment based on the Company’s guiding
- 23 principles, and,
- 24 4. Seeking stakeholder feedback, which was incorporated at multiple points in this
- 25 process.

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1 Each of these steps is discussed in more detail below.

2

3 **Q31. What was the Company's benchmarking process?**

4 A31. The Company analyzed six utility TEPs in-depth,⁹ chosen because of their recent
5 proposal or approval and the robustness of their included programs. The Company
6 also reviewed an industry benchmarking report in detail,¹⁰ and has consistently
7 participated in national EV working groups.¹¹ This work helped guide DTE
8 Electric's strategy and TEP development.

9

⁹ The six utilities included in benchmarking include Commonwealth Edison (ComEd), Consolidated Edison (ConEd), National Grid Massachusetts (National Grid), Southern California Edison (SCE), Xcel Colorado, and Xcel Minnesota. The TEPs benchmarked are:

- ComEd Beneficial Electrification Plan available at <https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf>, accessed December 5, 2023
- ConEd Electric Vehicle Infrastructure Make-Ready Program Implementation Plan available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b181AB1C0-0F11-44F6-B652-5705D91EC1B3%7d>, accessed December 5, 2023
- National Grid Direct Pre-filed Testimony of the Electric Vehicle Program Panel Exhibit NG-EVPP-1 available at <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106>, accessed December 5, 2023
- SCE Application of Southern California Edison Company (U338E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs available at <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K230/346230115.PDF>, accessed December 5, 2023
- SCE Decision on the Transportation Electrification Standard Review Projects, SCE's Medium- and Heavy-Duty Vehicle Charging Infrastructure Program available at <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF>, accessed December 5, 2023
- Xcel Colorado Transportation Electrification Plan 2021-2023 available at https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-2021-2023_TEP_Updated.pdf, accessed December 5, 2023
- Xcel Minnesota Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications available at <https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b90B25F82-0000-C32B-B70E-1C25A3E2A491%7d&documentTitle=20228-188061-07>, accessed December 5, 2023

¹⁰ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

¹¹ Alliance for Transportation Electrification, Midcontinent Transportation Electrification Collaborative, Electric Power Research Institute

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1 **Q32. What was the Company's high-level overview from the review of the TEPs?**

2 A32. The table below shows a high-level summary of the six TEPs at the time DTE
3 Electric benchmarked them.

4 **Table 3 Overview of Six TEPs Benchmarked as of Q4 2022^{12,13}**

5

Company	State	Electric Customers (millions)	Program Years	Investment (\$ millions)	# Charger Ports (L2 DCFC)	2030 EV Forecasts
ComEd	IL	4.1	'23-'25	\$270	7,730 196	700,000
ConEd	NY	3.8	'21-'25	\$290	18,500 457	500,000
National Grid	MA	2.2	'22-'25	\$278	31,400 393	500,000
SCE	CA	1.4	'21-'25	\$793	24,500 205	2,600,000
Xcel CO	CO	5.2	'21-'23	\$108	19,800 210	500,000
Xcel MN	MN	1.5	'23-'26	\$384	0 1,470	797,000

6

7 There are several key themes that emerged from the benchmarking:

- 8 1. Most of the TEPs outline investment and programs for a three- to five-year
9 timeframe, which is longer than a typical general rate case bridge and test period,
10 2. The TEPs can accommodate programmatic changes, as needed, in a dynamic
11 environment,
12 3. The TEPs generally emphasized Level 2 charging over DCFC to improve overall
13 customer affordability, due to the higher number of use cases for Level 2
14 charging, lower costs of installing Level 2 chargers compared to DCFCs, and
15 minimized grid impact, and

¹² Data for investment, program years, electric customers, and 2030 EV forecasts sourced from company TEP filings. Exceptions: # Charge Ports for SCE does not include the 870 sites approved for the Charge Ready Transport medium-duty and heavy-duty vehicle program; 2030 EV forecasts for ComEd and ConEd were estimated based on state EV targets and customer size

¹³ Since Q4 2022, Xcel CO has reached a settlement agreement on its TEP, Xcel MN has since withdrawn its TEP, and National Grid has since received approval for portions of its TEP

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1 4. The TEPs often include an emphasis on compliance with statewide regulations,
2 equity, multi-unit dwelling and fleet segments, supporting functions, and
3 managing incremental EV load, as well as a trend towards make-ready
4 incentives as opposed to utility ownership, discussed in more detail below.

5

6 **Q33. What has the Company found with respect to TEP regulation?**

7 A33. From a compliance perspective, seven states have legislative or regulatory
8 requirements for their investor-owned utilities to file periodic TEPs with their
9 utility commissions that describe the utilities' transportation electrification efforts
10 for the next three to five years. Utilities in Colorado, Illinois, New Mexico, Oregon,
11 and Washington are required to make such filings by state legislation while utilities
12 in Arizona and Virginia are required to do so by their utility commissions. States
13 that require TEPs generally call for updates every three to five years, reflecting the
14 need to modify programming based on experience as well as to revise plans to
15 address new transportation electrification goals or emerging state policies.¹⁴

16

17 Most states do not have requirements for their utilities to submit periodic
18 comprehensive TEPs, including many states with utilities that are actively investing
19 in transportation electrification. California and New York, together, account for
20 most of the \$3 billion in approved utility TE investments over the last 10 years in
21 the United States, yet neither state requires utilities to engage in a comprehensive
22 TEP process (although it has been proposed in California). In states like these,
23 utilities have filed TEPs to align with statewide environmental initiatives including

¹⁴ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment
available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

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1 statutory EV targets.¹⁵ The most impactful of these has been California’s Zero-
2 Emission Vehicle (“ZEV”) program and the related regulations that have set
3 increasingly stringent EV sales targets in California since 1990, with the most recent
4 amendment to the regulations, called the Advanced Clean Cars II regulations,
5 requiring all new passenger vehicles sold in California to be zero-emission by 2035.
6 Fifteen other states have since adopted the program.¹⁶ These states and California
7 are collectively called ZEV states, and their share of national EV sales is higher than
8 their share of the national population.¹⁷ This makes TEPs more likely to be filed in
9 these states compared to non-ZEV states.

10

11 **Q34. What has the Company found with respect to TEP equity policies?**

12 A34. An emphasis on equity, through supporting DACs and low- and moderate- income
13 (“LMI”) residential customers, is a key theme in most TEPs. The TEPs
14 benchmarked incorporated an equity focus in 20 to 40 percent of total plan
15 investments. The most common way in which these utilities are focusing on equity
16 is through enhanced program offerings for commercial customers located in DACs
17 (the definition varying by utility and state) and for residential customers that are
18 either located in DACs or that meet an income threshold set by the utility. For
19 example, National Grid proposed \$1,700 in make-ready and charger rebates for
20 customers that are in designated Environmental Justice Communities or that meet

¹⁵ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

¹⁶ Colorado, Connecticut, Delaware, Maine, Maryland, Massachusetts, Minnesota, New York, New Jersey, Nevada, Oregon, Rhode Island, Washington, Vermont, and Virginia

¹⁷ Evaluating Electric Vehicle Market Growth Across U.S. Cities available at https://theicct.org/wp-content/uploads/2021/12/ev-us-market-growth-cities-sept21_0.pdf, accessed December 5, 2023

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1 the low-income threshold and only up to \$1,000 for single-family homes (“SFHs”)
2 that do not meet these criteria.¹⁸

3

4 **Q35. What has the Company found with respect to MUD and fleet policies?**

5 A35. MUDS and fleets receive unique attention in most TEPs. MUDs do, mainly because
6 of the coordination issues between residents and those who own the property or
7 have a say in how it is managed, such as landlords or Homeowners Associations.
8 These coordination issues stem from the residents wanting EV charging but needing
9 these other stakeholders to approve or pursue the installation for them. Unless
10 landlords and Homeowners Associations are motivated to do this, MUD residents
11 are left without the ability to freely install chargers like single-family homeowners
12 can. There is also typically an equity focus. The TEPs benchmarked by the
13 Company feature increased incentives for, or programs limited to, MUDs located
14 in DACs, MUDs serving LMI residents, or having some other equity focus. For
15 example, Xcel Colorado has a utility-owned make-ready infrastructure program for
16 MUDs and offers a charger rebate for MUDs that meet income-qualified criteria or
17 that are in high emissions communities.¹⁹

18

19 Fleets, particularly medium- and heavy-duty vehicles (“MHDVs”), transit buses,
20 and school buses, are another segment that receive unique attention, especially
21 among larger utilities. Southern California Edison (SCE) has dedicated \$356 million

¹⁸ National Grid Direct Pre-filed Testimony of the Electric Vehicle Program Panel Exhibit NG-EVPP-1 available at <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106>, accessed December 5, 2023; Environmental Justice Communities defined by the State of Massachusetts

¹⁹ Xcel Colorado Transportation Electrification Plan 2021-2023 available at https://www.xcelenergy.com/staticfiles/xcelresponsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-2021-2023_TEP_Updated.pdf, accessed December 5, 2023

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1 through its Charge Ready Transport TEP to support the electrification of MHDVs
2 by providing low- or no-cost charging infrastructure.^{20, 21} As observed with MUDs,
3 some TEPs also have equity-focused programs or enhanced incentives within their
4 fleet programming. For example, Commonwealth Edison's (ComEd's) TEP
5 proposal included a \$120,000 rebate for electric school bus purchases while the
6 rebate for the buses serving DACs is 50% higher at \$180,000.²²

7
8 **Q36. What has the Company found with respect to the nature of TEP incentives?**

9 A36. Make-ready infrastructure programs are the most commonly offered type of
10 incentive program in the TEPs. A greater share of TEP capital budgets is allocated
11 to make-ready infrastructure programs versus own-and-operate programs.²³ In an
12 analysis of all United States utility TE filings from 2012 through Q3 2022,
13 conducted by the Midcontinent Transportation Electrification Collaborative in
14 2022, nearly \$2 billion had been allocated for make-ready infrastructure programs,
15 whereas in that same period, less than \$1 billion had been allocated for utility own-
16 and-operate programs.²⁴ DTE Electric's benchmarking found this trend to be
17 consistent in the three TEPs with significant capital budgets (excluding Xcel
18 Minnesota's withdrawn proposal), with 90% of their capital budgets being
19 allocated to make-ready infrastructure programs.

²⁰ SCE Decision on the Transportation Electrification Standard Review Projects, SCE's Medium- and Heavy-Duty Vehicle Charging Infrastructure Program available at <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF>, accessed December 5, 2023

²¹ Charge Ready Transport Advances Despite Pandemic-Related Challenges available at [Charge Ready Transport Advances Despite Pandemic-Related Challenges | Energized by Edison](#), accessed December 15, 2023

²² ComEd Beneficial Electrification Plan available at <https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf>, accessed December 5, 2023

²³ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

²⁴ Midcontinent Transportation Electrification Collaborative 2022 meeting; analysis only includes those filings listed on Atlas Public Policy EV Hub

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1 **Q37. What did the Company find with respect to the handling of supporting**
2 **functions in the benchmarked TEPs?**

3 A37. The benchmarked TEPs dedicate between 10% and 25% of their total TE spend on
4 other portfolio costs that include marketing, education, outreach, and program
5 support such as IT and program administration. Utilities recognize the need to
6 increase education on the benefits of EVs and spread awareness about their
7 programs. Proposals include expanding their websites and working with local car
8 dealerships. An extension of these programs, seen more commonly in the fleet
9 segment, includes advisory services such as call centers or dedicated staff to advise
10 customers. Per the ACEEE report, more than half the utility TEPs offer detailed
11 fleet advisory services, including fleet assessments, which give fleet operators
12 information on what electrification would cost them in terms of infrastructure
13 investments and ongoing vehicle charging.²⁵

14

15 **Q38. What else did the Company learn?**

16 A38. All benchmarked utilities emphasize the importance of strategically managing the
17 incremental load from EV charging to mitigate grid impacts. Most utilities have
18 participant requirements or incentives that support managed charging or Time of
19 Day rates. Both can influence customer charging behavior by encouraging or
20 requiring charging during off-peak hours. All utilities offer TOD rates to their
21 residential program participants and use their educational resources to encourage
22 off-peak charging. Although all utilities recognize the importance of strategically
23 managing the transition of additional load from EVs, especially as adoption
24 increases, managed charging is still in a relatively nascent stage. Only two utility

²⁵ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment
available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

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1 TEPs, those of National Grid and Xcel Colorado, offer an additional incentive for
2 participants to enroll in managed charging programs, similar to the DTE Electric
3 Smart Charge program today.^{26,27}

4

5 **Q39. What is the forecasted market size for EV registrations in DTE Electric's**
6 **service territory?**

7 A39. In DTE Electric's service territory of Southeast Michigan, EV sales have grown at
8 a compound annual growth rate (CAGR) of 90% from 2019 to 2022, with
9 approximately 13,100 EVs sold in 2022, compared to about 1,900 EVs in 2019.
10 Year to date, 77% of the newly sold EVs in Michigan are registered in DTE
11 Electric's service territory and 74% of these are all-electric.²⁸ There are currently
12 almost 46,000 EVs registered in Southeast Michigan, and, as shown in the Figure
13 below, the Company forecasts this number increasing to an estimated 326,000,
14 including MHDVs, by 2028, which is the timeframe of the Company's TEP.²⁹

15

²⁶ Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at <https://www.aceee.org/research-report/t2201>, accessed December 5, 2023

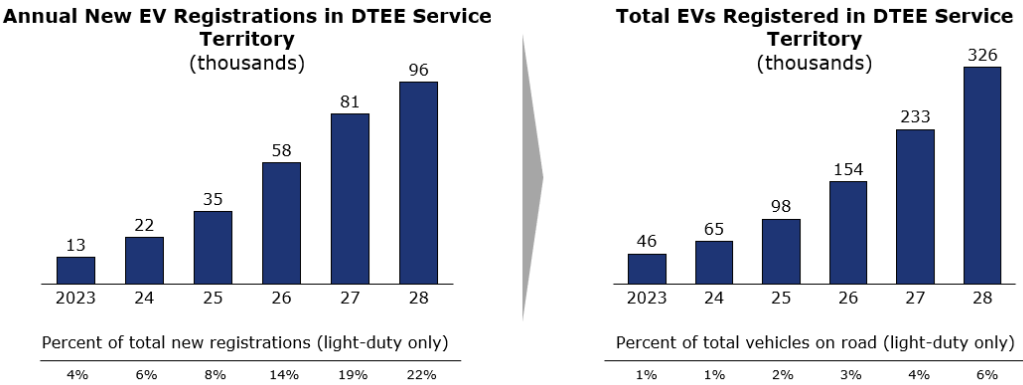
²⁷ DTE Electric Smart Charge brochure available at <https://www.dteenergy.com/content/dam/dteenergy/deg/website/residential/Service-Request/pev/plug-in-electric-vehicles-pev/SmartChargeBrochure.pdf>, accessed December 11, 2023

²⁸ The balance are plug-in hybrid EVs; regenerative hybrids and hydrogen fuel cell vehicles are not considered EVs

²⁹ Data for 2023 from S&P Global as of September 30, 2023; registration volumes (both actual and forecasted) include medium-duty and heavy-duty vehicles

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1 **Figure 1** **DTEE Forecast of Annual New EV Registrations and**
2 **Cumulative Registered EVs ³⁰**



3
4 **Q40. How did the Company arrive at this EV registration forecast?**

5 A40. This EV registration forecast, shown in the figure above, was derived from a
6 combination of a short-term forecast developed using recent registration data from
7 S&P Global and a long-term forecast derived from forecasts published by industry
8 experts. For the short-term forecast in 2024 and 2025, EV registrations were
9 determined using an exponential regression based on EV registrations in DTE
10 Electric service territory from 2018 through 2023. For 2027 and 2028, DTE Electric
11 EV registrations were derived from forecasts published in 2022 and 2023.³¹ To get
12 a Michigan EV forecast in the near term, a marginally lower forecast was factored
13 in to account for the lower growth rate in the near term for a non-ZEV state. The
14 fraction applied to the forecast to achieve this grows over time as, in the long term,
15 the Michigan EV sales rate is expected to be closer to the national EV sales rates.
16 2026 is the average of the forecast in 2025 and 2027, as it is the transitionary year

³⁰ Data for 2023 from S&P Global as of September 30, 2023; registration volumes (both actual and forecasted) include medium-duty and heavy-duty vehicles

³¹ Including those from Bloomberg New Energy Finance, Goldman Sachs, Electric Power Research Institute, International Council on Clean Transportation, Boston Consulting Group, and the U.S. Energy Information Administration

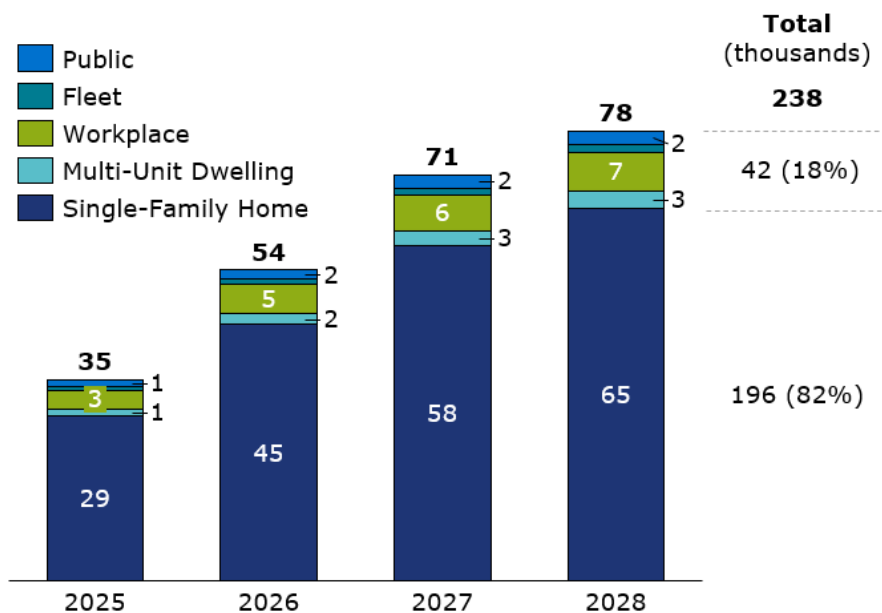
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1 between the short- and long-term forecasts. The Michigan EV forecast is then
2 converted to a DTE Electric EV forecast by applying another factor representing
3 the percentage of new EVs registered in the DTE Electric service territory
4 compared to the total registered in the state.

5
6 **Q41. What is the charging infrastructure required to support the forecasted EV**
7 **adoption?**

8 A41. The forecast shows an estimated increase to 326,000 EV registrations in 2028 from
9 the approximately 46,000 EVs registered in DTE Electric's service territory in
10 Southeast Michigan today. This increase in forecasted EV registration equates to
11 approximately 238,000 chargers being needed in DTE Electric's service territory
12 over the four-year TEP time horizon, increasing from approximately 35,000
13 chargers annually in 2025 to 78,000 annually in 2028, as shown in the figure below.

14
15 **Figure 2 Forecast of Incremental Chargers Needed in DTEE**
16 **Service Territory (thousands)**



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1 More than 80% of the estimated chargers needed to support the forecasted EV
2 adoption from 2025 through 2028 are projected to be at single-family homes. The
3 majority of the incremental chargers needed are Level 2 chargers, driven by the
4 residential segment that includes both single-family homes and MUDs.

5
6 **Q42. How was this charging infrastructure requirement evaluated?**

7 A42. First, the Company developed an overview of the needs of the five primary
8 customer segments. The five primary customer segments are consistent with the
9 TEPs benchmarked and are described in the table below.

10

11 **Table 4 Overview of Primary Customer Segments and Needs**

12

Segment	Customer Description	Market Needs
SFHs	Residential customers in detached homes which generally have a single electrical panel (includes buildings with three or fewer housing units)	- Longer duration charging is possible, so it can be served by Level 2 chargers (Level 1 charging was not considered for this analysis) - Cost of installation, which can be as much as \$8,000, can be barrier for low-income customers
MUDs	Commercial customers with buildings that have four or more housing units. Parking may be in shared lots or designated parking spots	- Longer duration charging is possible, so it can be served by Level 2 chargers except in unique situations (e.g., no parking) - If landlords lack motivation to install chargers, it deters EV adoption for residents
Public	Commercial customers owning chargers for public use, either at a destination (e.g., stores and restaurants) or on-route near a major thoroughway	- In some areas, Level 2 chargers are sufficient, but majority of charging needs, in the future, will be fulfilled by DCFCs that have a shorter charging time - In 2023, there was a lack of public charging infrastructure in disadvantaged and rural communities

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		identified within DTE Electric service territory
Fleet	Commercial customers owning chargers for business use. Fleets can be one or more light-duty vehicles and/or MHDVs	- Type of charger needed varies depending on type of EV, vehicle miles traveled, and parking duration(s) - Large fleet depots, particularly for MHDVs, can have high installation costs
Workplace	Commercial customers owning chargers for employee use with their personally owned vehicles	Longer duration charging is possible, so it can be served exclusively by Level 2 chargers. Over time, workplaces may be served by DCFCs, as well

1

2

Once the customer segments were defined, DTE Electric's EV registration forecast was proportioned into each customer segment.

4

5

The formula shown in the figure below was used to calculate the incremental number of chargers by customer segment and charger type (Level 2 or DCFC) for a given year:

8

9

**Figure 3 Formula for Incremental Number of Chargers, by
Customer Segment and Charger Type**

10

11

12

$$\text{Chargers} = \frac{\frac{\text{Number of EVs}}{\text{EVs per Charger Port}} \times \text{Charger Mix}}{\text{Ports per Charger}}$$

13

14

The incremental number of EVs forecasted each year was divided by the number of EVs served per charger port to arrive at the number of ports. EVs per charger port is assumed to be as low as one for single family homes and as high as approximately 200 for public on-route charging in 2028. The assumption is that the number of EVs

15

16

17

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1 per charger port increases over time, as adoption of EVs increases and chargers are
2 utilized more efficiently.

3

4 The number of ports calculated above was then segmented into charger type by
5 multiplying the number by the charger mix, which is a percentage representing the
6 assumed share of Level 2 or DCFC ports for that segment. The charger type for
7 single-family homes and MUDs was assumed to be 100% Level 2 chargers since
8 longer duration parking is expected. Public charging was assumed to be primarily
9 DCFCs. For fleet charging, the charger mix varies by use case and vehicle type; the
10 Company assumed 80% Level 2 charging for light-duty vehicles, 80% DCFCs for
11 larger vehicles and 100% DCFCs for buses.

12

13 Finally, the number of ports for each charger type was divided by the number of
14 ports per charger to arrive at the number of chargers by customer segment. The
15 number of ports per charger ranges from one to 1.3, depending on the segment and
16 the year. For example, one port per charger is assumed for single-family homes and
17 school buses, while the need for public charging increases to 1.3 ports per charger
18 in 2028.

19

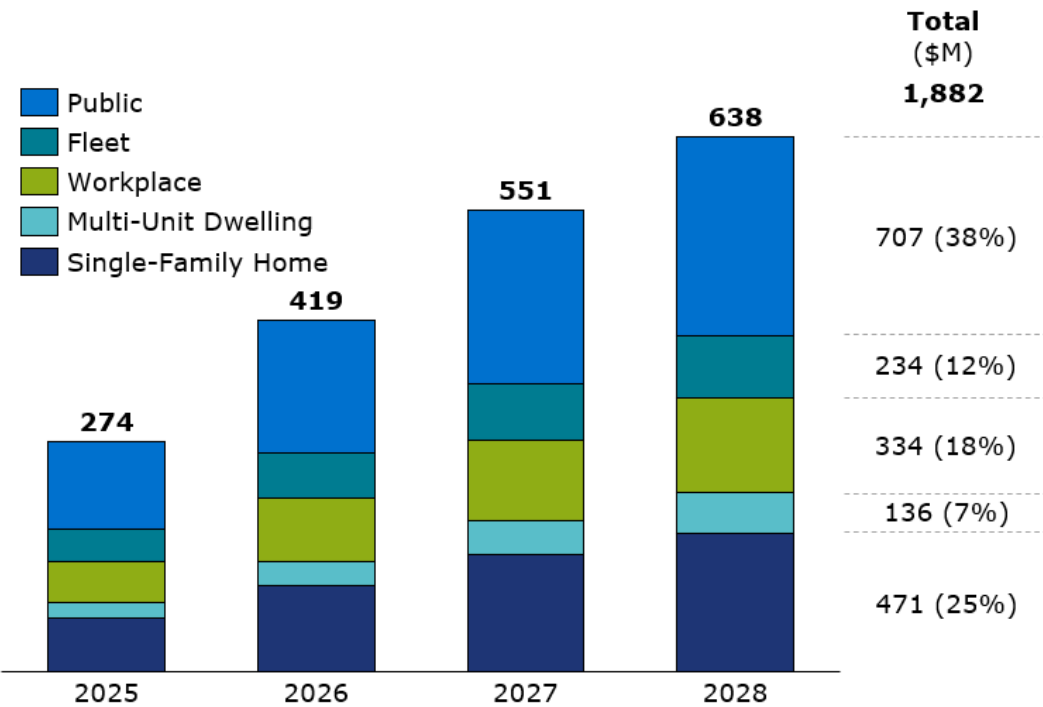
20 **Q43. What is the estimated investment required to support the number of chargers**
21 **needed?**

22 A43. The approximately 238,000 incremental chargers needed over the four-year TEP
23 time horizon will require nearly \$1.9 billion of infrastructure investment, funded
24 by a mix of public, private, government, and utility sources, increasing from

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1 approximately \$274 million in 2025 to \$638 million in 2028, as shown in the figure
2 below:
3

4 **Figure 4 Annual Investment Required for Charging Infrastructure in DTE**
5 **Electric Service Territory by Customer Segment (\$ millions)**
6



7
8 Even though the public charging segment represents just 3% of the chargers needed,
9 as shown in the figure above, it is the largest driver of investment required in the
10 near term at nearly 40% due to the high costs of DCFCs and the associated
11 installation. Conversely, although the single-family home charging segment
12 represents over 80% of the total projected chargers, they only require about 25% of
13 the total investment since they are much less expensive.
14

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1 **Q44. What assumptions were made in order to calculate the estimated investment**
2 **needed?**

3 A44. DTE Electric data were used to define cost assumptions by charger segment and
4 type, as shown in the table below:
5

6 **Table 5 Average Approximate Installation Costs by Charger Type and**
7 **Segment, 2025-2028³²**
8

Type	Segment	Utility Make-Ready	Customer Make-Ready	EV Charger	Total Cost
Level 2	SFH	\$230	\$1,580	\$590	\$2,400
	MUD	\$1,360	\$13,600	\$590	\$15,550
	Workplace	\$330	\$13,310	\$1,460	\$15,100
	Fleet	\$1,040	\$12,960	\$1,440	\$15,440
	Other Public	\$1,250	\$12,520	\$1,450	\$15,220
DCFC	School bus	\$16,510	\$61,900	\$32,750	\$111,160
	Transit bus	\$16,510	\$61,890	\$79,010	\$157,410
	Workplace	\$5,480	\$65,770	\$78,210	\$149,460
	Fleet	\$16,500	\$61,870	\$78,680	\$157,050
	On-route	\$20,630	\$61,890	\$78,790	\$161,310
	Destination	\$17,710	\$53,130	\$76,320	\$147,160

9
10 The Company also considered the following factors in developing its cost
11 assumptions:
12

- Inflation,

13

- Charger costs decreasing by 3% each year due to expected technological

14 advancements, and

³² Rounded to the nearest 10. Definitions and specific examples for utility make-ready, customer make-ready, and EV charger equipment are provided in Table 7 below. Utility make-ready includes customer-owned CIAC (typically 15% of total utility make-ready on average) and non-CIAC utility make-ready for which DTE Electric is responsible

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- 1 ▪ For every increase in project size by two chargers, charger costs were
2 reduced by 2% and installation costs were reduced by 5% for Level 2
3 chargers and 10% for DCFCs, on a per-charger basis. No further per-charger
4 cost savings were assumed for project sizes over ten chargers.

5

6 The impact of these factors on the cost assumptions is that charger and installation
7 costs decline as the number of chargers per location increases, and for a fixed
8 number of chargers per location, charger costs decline and installation costs increase
9 over time.

10

11 DTE Electric also reviewed internal project data that indicated that 20% of fleet
12 installations and 75% of workplace installations did not require any service
13 upgrades, so the utility make-ready (“UMR”) costs for these segments were reduced
14 accordingly. For single-family homes, the internal project data revealed that the
15 average customer make-ready (“CMR”) cost for “newer” buildings (built in 1980 or
16 after) is about half the average CMR cost for “older” buildings (built before 1980).
17 Similarly, it is estimated that newer single-family homes would experience about a
18 five-year delay on the kinds of UMR costs that older SFHs typically incur today.

19

20 The investment required does not include transmission or power supply costs.

21

22 **Q45. What was the Company’s approach to engaging stakeholders in the TEP**
23 **design?**

24 A45. DTE Electric engages stakeholders in its current Charging Forward programs by,
25 among other things, hosting annual stakeholder discussions and submitting

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1 quarterly and annual status reports in the Case No. U-20162 docket. Listening to
2 stakeholders during the TEP development helped DTE Electric produce a well-
3 balanced and well-aligned plan to serve customers. The Company implemented a
4 stakeholder engagement process aimed at providing transparency and obtaining
5 feedback on the overall approach and development phases of the planning to ensure
6 that its TEP balances the diverse interests of its stakeholders. This was achieved
7 through a series of webinars and surveys and included:

- 8 ▪ Focused discussions with the MPSC,
- 9 ▪ A kick-off webinar with stakeholders to explain the TEP approach, discuss
10 the guiding principles, and request their engagement,
- 11 ▪ Three separate webinars for the three key stakeholder groups (defined
12 below) to share our need assessment, customer segmentation, and charger
13 installation cost categories and to seek insights into stakeholder positions on
14 key things like which needs that DTE Electric should support, and whether
15 the Company should consider waiving Contribution in Aid of Construction
16 ("CIAC") for residential or business customers,
- 17 ▪ Three surveys following each stakeholder webinar to allow the stakeholders
18 to provide additional feedback, and
- 19 ▪ Individual follow-up meetings with organizations, if requested.

20 DTE Electric invited 110 organizations to engage in this process and about half of
21 the organizations invited participated, of which half belonged to the EV Industry
22 stakeholder group.

23

24 **Q46. What were the three key stakeholder groups?**

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1 A46. DTE Electric included more than 100 organizations that could be impacted by the
2 TEP and organized these into three key stakeholder groups: EV industry, customer-
3 facing, and policy & advocacy groups. The types of organizations in those key
4 stakeholder groupings are shown in the table below:

6 **Table 6 Types of Organizations in the Three Key Stakeholder Groups**

EV Industry	Customer-Facing	Policy & Advocacy
• Auto manufacturers • Charger manufacturers • Network providers • Charger installation companies	• Municipalities • Regional planning organizations • Transit agencies • Businesses • Gas and convenience store owners • Rental car companies • Transportation Network Companies	• MPSC • Regional advocacy groups • National advocacy groups

8

9 **Q47. What insights were garnered from stakeholders?**

10 A47. Stakeholders provided feedback through the stakeholder engagement process, most
11 of which was fairly aligned. There were some areas where stakeholders had
12 divergent opinions. The feedback that most stakeholders were aligned on included:

- 13 ▪ There is a need to provide charger rebates to facilitate EV adoption in the
14 near term,
- 15 ▪ Utility TEPs should have a strong focus on multi-unit dwellings, low-income
16 customers, and disadvantaged communities,
- 17 ▪ The resulting portfolio should provide net affordability benefits to all DTE
18 Electric customers using a robust BCA, and

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- 1 ▪ DTE Electric should also focus on grid modernization to help improve
2 reliability and on streamlining interconnection timelines to improve the
3 customer experience.

4 The process also identified the following differing positions:

- 5 ▪ Utilities should own chargers for specific use cases, such as curbside Level
6 2 charging and rural fast charging *versus* utility ownership should be
7 minimal and encouraged as a last resort,
8 ▪ There are clear failures in the EV charger market today *versus* it is premature
9 to assume failures in the nascent EV market in Michigan,
10 ▪ Utilities should waive CIAC from customers *versus* cost causation principles
11 of rate design (and appropriate credits based on expected load and revenue)
12 should remain in place for EV requests, similar to new service requests and
13 upgrades, and
14 ▪ Charging infrastructure needs and corresponding investment identified in the
15 need assessment for DTE Electric's TEP should be based on the aspirational
16 EV goal of two million EVs by 2030 in the MI Healthy Climate Plan *versus*
17 basing them on DTE Electric's EV forecast.³³

18
19 **Q48. How was the TEP informed by stakeholder feedback?**

20 A48. In accordance with the Company's guiding principles, DTE Electric had already
21 envisioned supporting and accelerating EV adoption by facilitating charger
22 deployment while ensuring affordability benefits for all DTE Electric customers
23 and promoting equity by focusing on low-income customers and disadvantaged

³³ MI Healthy Climate Plan available at <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>, accessed December 18, 2023

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1 communities, which are things that TEP stakeholders valued as well. After
2 receiving insights from stakeholders, DTE Electric also decided:

- 3 ▪ not to waive CIAC beyond revenue credits from existing line extension
- 4 policy,
- 5 ▪ to use its own EV forecasting methodology to determine charging
- 6 infrastructure needs, and
- 7 ▪ not to include utility-owned pole-mounted chargers with this initial TEP.

8 The Company believes that there is merit in the utility owning and operating pole-
9 mounted chargers due to the lower costs along with the opportunity to seek federal
10 funding at scale, and the ability to provide more affordable overnight charging
11 solutions for DACs and MUDs. However, in order to achieve consensus where
12 possible, the Company has opted not to include any utility-owned charging with its
13 initial TEP.

14

15 **Q49. What framework did DTE Electric use to develop the TEP?**

16 A49. DTE Electric evaluated the participation models for each of the customer segments,
17 leveraging the guiding principles and stakeholder feedback.

18

19 First, DTE Electric defined the three primary cost categories for charger installation
20 and refined the five primary customer segments.

21

22 The three primary cost categories for charger installation help provide
23 considerations for utility support for EV charging. Definitions and specific examples
24 for these three cost categories, which include utility make-ready, customer make-
25 ready, and EV chargers are provided in the table below:

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1 **Table 7 Charger Installation Cost Category Definitions and Examples**

2

	Utility Make-Ready	Customer Make-Ready	EV Charger
Description	Upgrades on the utility side of the meter, from the line transformer to the meter	Upgrades on the customer side of the meter, from after the meter to the EV charger stub out	Hardware required to charge the EV
Examples	- Grid edge infrastructure (e.g., pole top transformer) needs to be upgraded to support residential EV load - Another service line needs to be added to support EV chargers in a parking lot	- A residential customer upgrades the panel to support an EV Charger - A commercial customer installs conduit and cable from the panel to the charger stub out	- Level 2 chargers - DCFCs

3

4 The five primary customer segments were further divided into sub-segments to

5 allow DTE Electric to examine specific needs and dynamics at a more granular level

6 to appropriately determine the degree to which the Company should participate.

7 These sub-segments are defined in the table below:

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1

Table 8 Overview of Customer Sub-Segments

2

Segment	Customer Sub-Segments	Description of Location or Use Case
Single-Family Homes	Low-Income	Level 2 chargers for SFH residents within 200% of federal poverty limit
	Non-Low Income	All other Level 2 chargers at SFHs
Multi-Unit Dwellings	Low-Income	Level 2 chargers at affordable MUD housing (e.g., public housing, government-subsidized private housing, etc.)
	Non-Low Income	All other Level 2 chargers for MUDs
Public	DAC/rural on-route DCFC	DCFCs within one mile of a major thoroughway and in DACs and/or rural areas
	All other on-route DCFC	All other DCFCs within one mile of a major thoroughway
	Destination DCFCs	All DCFCs further than one mile from a major thoroughway
	Destination Level 2	All Level 2 public charging, including pole-mounted charging
Fleet	Transit agencies	DCFCs serving transit buses
	Schools	DCFCs serving school buses
	Level 2	Level 2 charging for fleet EVs, typically light-duty vehicles
	All other DCFCs	All other DCFCs for fleet EVs
Workplace	-	Chargers for employee use with personally owned vehicles

3

4

The ways in which DTE Electric ultimately decided to support the above customer sub-segments, including justification for its proposal are included in the following TEP Portfolio Proposal section.

5

6

7

8

II. TEP Portfolio Proposal

9

Q50. What are the Company's proposed TEP programs?

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1 A50. DTE Electric's proposed TEP programs achieve its guiding principles by
2 facilitating charger deployment while maintaining overall affordability benefits for
3 all DTE Electric customers, improving economics of electrification in the near-
4 term, and promoting equity with a focus on low-income customers and
5 disadvantaged communities. The portfolio is summarized in the table below:

7 **Table 9 Proposed TEP Rebate Programs, 2025-2028**

Customer Segment	Customer Sub-Segments	Rebate ³⁴	Segment Availability	Total Investment (\$ millions)
SFHs	LI Level 2	\$2,200	100%	24.0
MUDs	LI Level 2	\$14,400	90%	7.0
	Non-LI Level 2	\$5,000	45%	20.7
Public	DAC/rural on-route DCFC	\$70,000	35%	21.6
	All other on-route DCFC	\$50,000	35%	15.4
Fleet	Transit bus DCFC	\$70,000	100%	2.3
	School bus DCFC	\$70,000	30%	7.0
	Other DCFC	\$70,000	30%	20.0
	Other Level 2	\$2,500	90%	6.8
Total	-	-	-	124.8

9
10 The on-route charging segment makes up the biggest category of investment at 30%,
11 followed closely by fleet at 29%, MUDs at 22% and single-family homes at 19%.
12 A benefit cost analysis is provided in the next section.

13

³⁴ LI SFH and LI MUD are average estimates based on total installation costs and would not exceed actual costs

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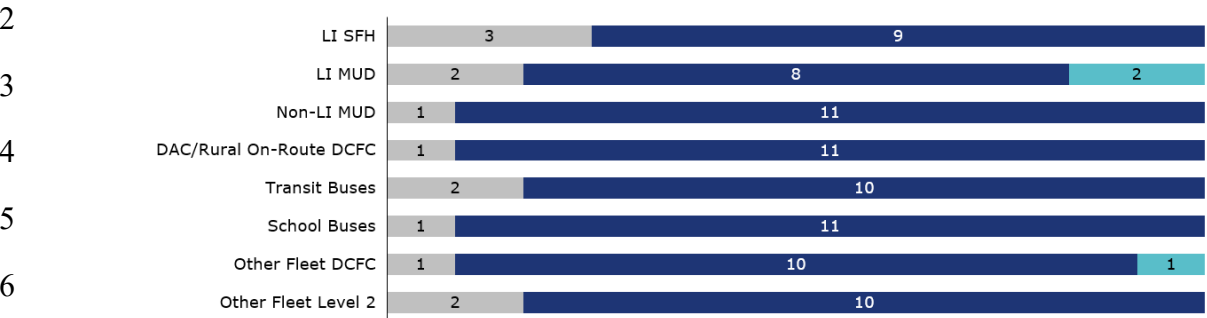
1 **Q51. How was the final portfolio informed by stakeholder feedback?**

2 A51. The Company provided a preview of its proposed TEP programs to the stakeholders
3 in October 2023 and sent a survey to participants following the discussion. 83% of
4 the survey participants stated that they were either “satisfied” or “very satisfied”
5 with the proposed TEP programs; the balance stated they were “neutral”. The figure
6 below shows the survey responses on the proposed rebate amounts by customer
7 sub-segment:

8

9 **Figure 5 Survey Responses to Proposed Rebate Amounts by Sub-**
10 **Segment^{35,36}**

11



17

18 The greatest impact stakeholder feedback had on the final proposed TEP was the
19 inclusion of the non-DAC/Rural on-route DCFC customer segment in the TEP. This
20 customer segment was not included in the TEP preview shown to stakeholders, and
21 as such is not included in the survey questions shown in the previous figure. In

³⁵ The 12 survey respondents included representatives from BorgWarner, BP Pulse, ChargerHelp, EV Connect, Flo EV Charging, General Motors, Michigan Auto Dealers Association, Michigan Energy Innovation Business Council (MEIBC), Michigan Public Service Commission, Southeast Michigan Council of Governments (SEMCOG), Tesla, and University of Michigan.

³⁶ Note that non-DAC/Rural on-route DCFC is missing from this survey, because this customer segment was not included in the TEP preview this survey was designed to complement, but in response to stakeholder feedback it was added to the final proposed TEP.

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1 response to stakeholder feedback at this and other webinars (for example,
2 stakeholders ranked this customer segment the third-most important for utility
3 action), the Company decided to add the non-DAC/Rural on-route DCFC customer
4 sub-segment to the final portfolio of proposed TEP programs.

5

6 **Q52. What is the justification behind the Company's support of the Single-Family**
7 **Home segment?**

8 A52. The Company is proposing support for Home Charger Rebates for low-income
9 residential customers in single family homes over the TEP timeframe at 100% of
10 the forecasted charger deployments for this subsegment in the DTE Electric service
11 territory, for a total investment of approximately \$24 million. The proposed rebate
12 would cover the cost of the Level 2 charger and the full cost of the customer's
13 installation and is calculated at an average of \$2,200 per rebate.
14 The Company has focused its support on the low-income single-family home
15 subsegment for these reasons:

- 16 ■ While over 80% of the chargers needed between 2025 and 2028 are expected
17 to be in the single-family home segment, per Figure 2 above, the Company
18 and stakeholders believe that EV adoption in the non-low-income sub-
19 segment is unlikely to be solely determined by the cost to install a home
20 charger. However, this can be a significant barrier for low-income residential
21 customers,
- 22 ■ Customers need to install a charger at home to unlock the fuel pricing of
23 approximately \$1 eGallon equivalent and experience the benefits and
24 features of a dedicated EV charger,

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- 1 ▪ Customers can face high installation costs due to outdated electrical wiring
- 2 and/or breaker panels. While the average total cost of installation is \$2,400,³⁷
- 3 the range can vary from as low as \$750 to as high as \$7,850, based on a
- 4 review of more than 500 installations completed through the Company's
- 5 Home Charger Installation pilot program,
- 6 ▪ The Company received strong stakeholder support for this approach with
- 7 one key stakeholder stating, in a feedback webinar, that "[the low-income]
- 8 community needs resources to move to EV adoption. This segment cannot
- 9 be left behind."

10

11 **Q53. What participation criteria will the Company require for the income-qualified**
 12 **Home Charger Rebates?**

13 A53. Initially, the Company envisioned a low- and moderate-income customer eligibility
 14 threshold of 400% of the federal poverty limit. Some key stakeholders gave us
 15 feedback that this was too high. Consequently, DTE Electric lowered the income
 16 eligibility threshold to 200% of the federal poverty limit, which aligns with the
 17 threshold for other DTE low-income programs³⁸ and would be approximately
 18 \$60,000 for a four-person household.

19 Other qualification requirements are:

- 20 ▪ Proof of EV purchase or lease,
- 21 ▪ Installation of an ENERGY-STAR certified or vehicle manufacturer charger
- 22 less than or equal to 12 kilowatts, and

³⁷ Total cost of installation includes DTE Electric costs of about \$200 for non-CIAC utility make-ready

³⁸ The Energy Efficiency Assistance program and Shutoff Protection Plan are two such DTE programs

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- 1 ▪ Enrollment in a Time of Day (“TOD”) rate, such as Whole-Home TOD
- 2 (D1.2), Dynamic Peak Pricing (D1.8), EV-only TOD (D1.9), or the recently
- 3 approved Overnight Savers (D1.13).

4

5 **Q54. Are there additional considerations for the income-qualified Home Charger**
 6 **Rebates proposal?**

7 A54. Yes. It will be critical to monitor and adjust the income eligibility threshold based
 8 on market dynamics of EV adoption. For example, if the upfront premium for EVs
 9 continues to remain out of reach for low-income customers, DTE Electric may need
 10 to adjust the income threshold of the Home Charger Rebate program upwards to
 11 meaningfully support this segment and encourage EV adoption in Southeast
 12 Michigan.

13

14 **Q55. What is the justification behind the Company’s support of the Multi-Unit**
 15 **Dwelling segment?**

16 A55. The Company is proposing to support the multi-unit dwelling (“MUD”) segment
 17 for both low-income MUD housing and for all other MUDs with two separate
 18 programs.

19 The Company is proposing support for rebates for qualified low-income MUDs at
 20 about 90% of the forecasted MUD charger deployments in this subsegment over the
 21 TEP timeframe, for a total investment of approximately \$7 million. The proposed
 22 income-qualified Business Charger Rebate would cover the cost of the Level 2
 23 charger and the full cost of the installation that the customer is responsible for
 24 paying, including the CIAC portion of the utility make-ready and the customer
 25 make-ready. The average rebate is calculated at \$14,400 per charger.

Line
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1

2

The Company is also proposing support for all other MUDs at about 45% of the forecasted MUD charger deployments in this subsegment over the TEP timeframe, for a total investment of approximately \$20.7 million, to cover the cost of the charger and a portion of the installation. The proposed revised Business Charger Rebate would be \$5,000 and would cover the cost of the Level 2 charger.

3

4

5

6

7

8

The Company proposes supporting this segment in this manner for the following reasons:

9

10

- As discussed in the single-family home segment above, access to overnight charging is critical to unlock fuel savings and this can be a purchase barrier for EVs,

11

12

13

- The average total cost of installation (less utility-owned non-CIAC utility make-ready) is approximately \$14,400 over the TEP timeframe, as shown in Table 9, driven primarily by customer make-ready, which often requires trenching and extending electrical wiring to parking areas,

14

15

16

17

- The cost of installation can make it a challenge for landlords, especially in the low-income or affordable housing subsegment, to install EV chargers,

18

19

- While landlords in segments other than the low-income subsegment may have some incentive to install chargers as an amenity to attract tenants and retain occupancy, landlords in the low-income subsegment may not have the same motivation or resources to install EV chargers,

20

21

22

23

- As discussed above, benchmarking shows that MUDs are receiving unique attention in other utility TEPs due to some of the same reasons outlined above, and

24

25

Line
No.

- 1 ▪ Stakeholders surveyed by DTE Electric ranked the low-income MUD
2 housing segment as the fourth most important subsegment for utility action.

3

4 **Q56. What participation criteria will the Company require for the rebates in the**
5 **MUD segment?**

6 A56. To qualify for the income-qualified Business Charger Rebate, the MUD must meet
7 at least one of the following criteria:

- 8 ▪ MUD is owned and managed by a public entity such as the Housing
9 Commission,
10 ▪ MUD receives government subsidization that requires at least 40% of the
11 units to be for residents whose household incomes do not exceed 60% of the
12 area median income (such as the LI Housing Tax Credit),
13 ▪ MUD has at least 40% of their residents participating in the Housing
14 Voucher Program, or
15 ▪ Other criteria deemed equivalent to those above.

16

17 Qualification requirements proposed for both income-qualified and non-income
18 qualified Business Charger Rebates include:

- 19 ▪ Installation of a qualified, networked charger (similar to the Business
20 Charger Rebates program today),
21 ▪ Authorizing network provider to share charger data with DTE Electric,³⁹
22 ▪ Commitment to 97% charger uptime, and

³⁹ Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

Line
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- 1 ▪ Demonstrated tenant interest in installing EV chargers; this helps protect
2 utility investment through greater likelihood of utilization of charging-
3 related assets and investment.

4

5 **Q57. Are there additional considerations for the Business Charger Rebates for**
6 **multi-unit dwellings?**

7 A57. Yes. There are two additional considerations for the Business Charger Rebates in
8 the multi-unit dwelling segment:

9 1. The Company believes that Level 2 charging is appropriate for the longer
10 parking duration at MUDs. This enables fuel savings for tenants while
11 minimizing impacts to the DTE Electric grid. However, the Company is
12 proposing that an exception could be made to allow rebates for DCFCs at MUDs
13 in special cases, for example, if there is extremely limited parking space for
14 residents.

15 2. One quarter (25%) of the stakeholder survey respondents indicated that DTE
16 Electric's proposed support of the low-income MUD market was too much and
17 one quarter (25%) of the survey respondents indicated that DTE Electric's
18 support of the non-low-income MUD market was not enough. These results
19 warrant the flexibility for DTE Electric to adjust the low-income MUD housing
20 qualification requirements and the rebate amounts in this segment based on
21 market demand to help appropriately enable MUD resident EV adoption during
22 the TEP timeframe.

23

24 **Q58. Can you explain the reasons for the Company's support of the Public**
25 **Charging segment?**

Line
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1 A58. Stakeholders ranked all the public charging subsegments, including on-route and
2 destination charging, as the most important for utility action because the availability
3 of public charging is critical to reducing range anxiety, which is a key barrier to EV
4 adoption. Reliable, on-route fast charging, defined as fast charging within one mile
5 of a major throughway exit, can increase customer's confidence in the refueling
6 infrastructure and so, the Company is proposing to provide support for on-route
7 public fast charging by offering a rebate of \$70,000 per on-route DCFC in
8 disadvantaged communities and rural areas and \$50,000 per on-route DCFC in
9 other areas. To manage affordability impacts to its customers, DTE Electric
10 proposes to support 35% of the forecasted on-route public charger deployment for
11 an investment of \$21.6 million in the DAC and rural on-route subsegment and \$15.4
12 million in other on-route areas.

13

14 As noted above, public charging represents the highest category of investment
15 required over the TEP timeframe because of the expensive hardware and the high
16 cost of installation of DCFCs driven by high-voltage wiring. Site hosts seek higher
17 utilization rates to recoup their investments which tends to concentrate private sector
18 investment in higher-income areas that have high EV adoption rates. This is
19 reflected in DTE Electric's increased support for the DAC and rural on-route
20 subsegment as compared to the other on-route areas.

21

22 The Company expanded its support to on-route DCFCs not in DAC or rural areas
23 based on stakeholder feedback in the development phase. Stakeholders consider
24 utility support in this area critical in the near-term to decrease range anxiety and to
25 complement available federal funding opportunities, such as the NEVI program.

Line
No.

1 DTE Electric does not, however, propose rebates for the destination charging
2 segments as the economics of Level 2 charger deployment are not as challenging,
3 and businesses have other motivation for installation such as increased foot traffic.
4 For site hosts installing a destination DCFC, DTE Electric will continue to offer a
5 commercially available rate without demand charges for sites less than one
6 megawatt.⁴⁰

7

8 **Q59. What participation criteria will the Company require for its on-route Business**
9 **Charger Rebates program?**

10 A59. Participating customers will need to install a qualified, networked charger (similar
11 to the Business Charger Rebate program today), authorize the network provider to
12 share charger data with DTE Electric, and commit to 97% charger uptime.⁴¹

13

14 To qualify for the DAC on-route rebate, a community will need to be identified as
15 disadvantaged by the Michigan State Plan for EV Infrastructure Deployment.⁴²

16 To qualify for the rural on-route rebate, a community will need to be identified as
17 rural as viewed on the U.S. Department of Transportation Rural Eligibility Map.⁴³

18

⁴⁰ General Service Rate D3 as described in DTE Electric Company Rate Book for Electric Service available at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cur.pdf?rev=e0168ab41b8245bba5f3ca7631c29614&hash=D16249E421EC5AB0F5C3A2304B0FB0F7>, accessed December 18, 2023. Sites over one megawatt also qualify through June 2026

⁴¹ Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

⁴² Michigan State Plan for EV Infrastructure Deployment available at <https://www.michigan.gov/mdot/travel/mobility/initiatives/nevi>, accessed December 18, 2023

⁴³ Rural defined as, "located outside of a U.S. Census-designated urban area with a population of 50,000 or more." Rural Eligibility available at <https://www.transportation.gov/rural/eligibility>, accessed December 11, 2023

Line
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1 **Q60. How does the Company propose continuing its support of the Fleet Charging**
2 **segment?**

3 A60. Transit and school bus electrification have received unique attention in
4 governmental policy and funding programs due to the expected community
5 benefits. Due to the high upfront premium of electric buses, additional support is
6 often needed to improve economics even with the available funding. Although
7 school bus chargers are lower cost, on average, than transit bus chargers, schools
8 require more incentives to convert since the buses drive fewer miles than transit
9 buses and so do not achieve the same level of fuel savings to offset the upfront
10 premium. DTE Electric stakeholders ranked this subsegment high in terms of
11 importance for utility action, following public charging and low-income MUDs
12 (see Figure 5).

13

14 Therefore, the Company is proposing to continue its eFleet Charger Rebate program
15 for both school and transit buses with a rebate of \$70,000 per DCFC, assuming 60
16 kW and 150 kW DCFCs for those subsegments respectively. DTE Electric proposes
17 supporting 100% of the transit bus charger subsegment over the TEP timeframe for
18 a total investment of approximately \$2.3 million. The Company proposes a total
19 investment of approximately \$7 million to support 30% of the forecasted school bus
20 chargers needed while interest and affordability evolves.

21

22 DTE Electric also proposes to continue offering a \$2,500 eFleet Charger Rebate for
23 all fleet owners installing a Level 2 charger. The Company proposes supporting 90%
24 of the forecasted charger deployments in this subsegment for a total investment of
25 \$6.8 million. Encouraging Level 2 charging for fleets improves the total cost of

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1 ownership economics, which is a key driver for fleet conversion, while also reducing
2 grid impacts and supporting DTE Electric customer affordability.

3

4 The Company also proposes continuing offering up to a \$70,000 eFleet Charger
5 Rebate for DCFCs for approximately 30% of the forecasted charger deployments
6 for a total investment of \$20 million.

7

8 **Q61. What participation criteria will DTE Electric require for the Fleet Charging**
9 **segment?**

10 A61. Participating fleet customers will need to install a qualified, networked charger
11 (similar to the eFleet Charger Rebate program today), authorize the network
12 provider to share charger data with DTE Electric, agree to load commitments, and
13 commit to demand ceilings in constrained areas or for large depots to help manage
14 grid impacts.⁴⁴ Additionally, schools will need to install vehicle-to-grid chargers to
15 be eligible for the full \$70,000 rebate.

16

17 **Q62. Are there additional considerations for the TEP portfolio proposal?**

18 A62. Yes. There are four additional considerations:

19 1. DTE Electric investment is designed, at the portfolio level, to:

20 a. Maintain affordability benefits for all DTE Electric customers, as
21 calculated using the BCA methodology discussed in the next section, and

⁴⁴ Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if the charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

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1 b. Remain within the total MPSC-approved level of investment, which is
2 being proposed at \$125 million for rebates and \$20 million for
3 supporting functions over the TEP timeframe from 2025 to 2028.

4 2. As indicated in the explanation of multiple segments in this section, maintaining
5 flexibility to adjust TEP programming within the approved investment limits
6 and while maintaining affordability at the portfolio level, will be critical to
7 successfully enable overall EV adoption during the TEP timeframe. EV's are
8 still relatively new and evolving and DTE Electric can envision several
9 developments like EV pricing challenges, charger technology advancement,
10 supply chain constraints, federal incentive changes, private investment changes,
11 and EV sales not occurring as forecasted, requiring complementary modification
12 in TEP programming. Examples of adjustments the Company may need to make
13 to further TEP success in achieving its goals include changing rebate dollar
14 amounts, customer eligibility criteria, terms and conditions, and rebate volume
15 by subsegment.

16 3. DTE Electric is not proposing to support the workplace charging subsegment as
17 it is believed that there is sufficient incentive for workplaces to install chargers
18 as an amenity to attract employees, and

19 4. Electric Choice customers, if they request a rebate, will receive a discounted
20 rebate of about 35% (for example, up to \$25,000 instead of \$70,000 per charger)
21 to maintain affordability benefits for all DTE Electric customers by accounting
22 for the lower amount of rate revenue received from Electric Choice customers.

23

24 **Q63. What rate book modifications is the Company proposing as part of its TEP?**

Line
No.

1 A63. The Company is proposing the following modification in rate book language as
2 sponsored by Company Witness Willis:

3 ▪ Deletion of the Charging Forward CIAC waiver in section C6.1(16) of
4 Section C – Part I, Company Rules and Regulations.

5

6 **Q64. Why is the Company requesting the deletion of the Charging Forward CIAC**
7 **waiver?**

8 A64. Consistent with providing positive rate impacts and affordability benefits accruing
9 to all customers, DTE Electric decided, as part of its TEP, to no longer waive CIAC
10 beyond revenue credits from the existing line extension policy. This is also in
11 alignment with feedback received from key stakeholders. Making the rate book
12 modification as described above will align the rate book and the TEP.

13

14 **Q65. How did you support the design of the Company's EV Fast Charger Rate?**

15 A65. Under my direction, a list of 68 known DTE Electric DCFC customers was
16 generated and provided to Company Witness Willis. This list was initially compiled
17 using data from the Alternative Fuels Data Center,⁴⁵ and supplemented using
18 Charging Forward participant data.

19

20 **Q66. How will DTE Electric engage key stakeholders during the TEP timeframe?**

21 A66. DTE Electric proposes to continue providing Annual Status Reports for its TEP
22 programs.

23

⁴⁵ Alternative Fuels Data Center, available at [Alternative Fuels Data Center: Alternative Fueling Station Locator \(energy.gov\)](https://afdc.energy.gov/stations/#/analyze?region=US-MI&fuel=ELEC&ev_levels=dc_fast), https://afdc.energy.gov/stations/#/analyze?region=US-MI&fuel=ELEC&ev_levels=dc_fast, and accessed December 6, 2023. Advanced filter choices included Location: Michigan, Fuel: Electric and DCFC, Station: Public and Available

Line
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1 **Q67. What metrics does the Company propose to track?**

2 A67. The Company proposes to track the following metrics, by segment:

- 3 ▪ Rebate applications filed,
- 4 ▪ Rebate applications approved,
- 5 ▪ Charger uptime,
- 6 ▪ Charger utilization rate,
- 7 ▪ On-peak and off-peak charging,
- 8 ▪ Customer satisfaction,
- 9 ▪ Total investment including equity-focused programs, and
- 10 ▪ Installation cost per port, including utility make-ready investment, customer-
- 11 owed contribution in aid of construction, customer make-ready, and charger
- 12 costs.

13 These metrics will be tracked to guide necessary adjustments to program parameters
 14 to further customer affordability and overall effectiveness of the TEP. The Company
 15 will also monitor program activity and feedback to remain agile and scale its
 16 programs in accordance with its guiding principles and to successfully influence
 17 EV adoption.

18

19 III. Benefit Cost Analysis (“BCA”)

20 **Q68. What methodology was used to evaluate the TEP BCA?**

21 A68. In the November 2022 Order in Case Number U-20836, the Michigan Public
 22 Service Commission requested that DTE Electric “*submit a full scale, well-*
 23 *developed, permanent Charging Forward proposal that includes a BCA.*” The
 24 Commission additionally stated that “*the requirement of a BCA should not be*
 25 *interpreted as a requirement that all pilots be financially solvent at the time they*

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1 *are proposed (although that is preferable) but that when weighing costs versus*
2 *benefits for a full-scale program, benefits outweigh costs over the duration of the*
3 *program.”* As such, DTE Electric developed a robust BCA for the TEP that can be
4 evaluated by segment and for the whole TEP portfolio. This BCA shows that the
5 TEP portfolio provides net benefits to customers over its duration.

6

7 DTE Electric used the net present value (“NPV”) of the revenue requirement
8 assessed for the TEP programs as the BCA test for the TEP. Revenue requirement
9 is the required additional revenue that DTE Electric needs to collect from customers
10 to recover the cost of administering the TEP programs. When the TEP programs
11 produce positive revenue requirement NPV, customers will end up, all things equal,
12 paying higher electric rates. Conversely, when the TEP programs produce negative
13 revenue requirement NPV, the TEP provides an offset to electric rates.

14

15 **Q69. What are the key assumptions incorporated in the BCA analysis?**

16 A69. The revenue requirement analysis takes the following elements into consideration,
17 segmented by their effects, where (+) means they are adding rate pressure, whereas
18 (-) means they are providing rate relief:

- 19 ■ (+) utility-owned UMR investment for rebated chargers,
- 20 ■ (+) rebates for chargers,
- 21 ■ (+) supporting function costs (for portfolio-level BCA only),
- 22 ■ (+) energy cost of serving "qualified" additional EV load, and
- 23 ■ (-) electric revenue from “qualified” additional EV load.

24

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1 It is important to note that the BCA only considers incremental load from rebated
2 chargers (i.e., “qualified” additional EV load). The “qualified” additional EV load
3 occurring on TEP-supported chargers – and accounted for in the BCA – is only about
4 10% of the total expected EV load through 2030.

5
6 The rebated charger utilization rates used for the BCA are listed by charger type and
7 customer segment in the table below:
8

9 **Table 10 Charger Power and Utilization Rate by Customer Sub-segment and**
10 **Charger Type**

Charger Type	Customer Sub-Segment	Utilization Rates ⁴⁶
Level 2 12kW	SFH	2%
	MUD (LI / all other)	6% / 9%
Level 2 19kW	Workplace	1%
	Other fleet	7%
	Destination	8%
DCFC 60kW	School bus	4%
DCFC 150kW	Transit bus	14%
	Workplace	<1%
	Other fleet	5%
	On-route (disadvantaged community & rural / all other)	2% / 4%
	Destination	1%

12
13 For additional conservatism, the BCA assumes a constant utilization rate, despite
14 the utilization rate likely increasing over time, especially in segments where
15 chargers serve multiple vehicles, such as on-route DCFCs. For most segments, the
16 utilization rate used in the BCA is the average across the four TEP program years
17 as output from the segment assessment model, discussed above. For a few other

⁴⁶ Utilization rates used in the BCA are outputs from the market assessment process

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1 segments, utilization rates were chosen using Charging Forward data instead. For
2 example,

- 3 ▪ Low-income MUDs and on-route DCFCs in DACs used the lower-end of a
- 4 range of utilization rates from recent Charging Forward data, and
- 5 ▪ Other fleet DCFCs used a utilization rate in line with experience from eFleet
- 6 Advisory Services.

7

8 The energy cost of serving “qualified” additional EV load was calculated for each
9 customer segment as an annual weighted average derived from hourly wholesale
10 power price forecasts, consistent with the Company’s 2022 Integrated Resource
11 Plan filing (Case No. U-21193 Order dated July 26, 2023). Electric revenue from
12 “qualified” additional EV load was calculated based on electric tariff rates for EV
13 customers in their applicable rate classes. The 2024 values for electric tariff rates
14 and the cost of energy values by customer segments are listed in the tables below:

15

16 **Table 11 2024 Values for Electric Tariff Rates**

17

Input	\$/kWh	Source
SFH charger revenue	0.1502	Weighted average of residential rates D1.11, D1.2, and D1.9 ⁴⁷
All other charger revenue	0.1340	General service rate D3 (no demand charges) ⁴⁸

18

⁴⁷ Using EV Data Sharing pilot data (participant tariffs and split of on-peak vs. off-peak charging for the corresponding tariffs).

⁴⁸ The Company does not anticipate the 1 MW threshold waiver sunset of June 2026 to affect the BCA as the vast majority of DCFC installations will remain below the acceptable threshold. However, DTEE will address this if needed after June 2026.

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1 **Table 12 2024 Cost of Energy Values by Customer Segment⁴⁹**

2

Customer Segment	Cost of Energy (\$/kWh)
Single-Family Homes	0.0411
Multi-Unit Dwellings	0.0412
Public	0.0414
Fleet	0.0385
Workplace	0.0408

3

4 The revenue requirement is calculated using standard utility financing costs and
5 accounting treatment:

- 6 ▪ Rebates are treated as a regulatory asset (amortized over a five-year period),
- 7 ▪ Utility-owned UMR investments are capitalized (depreciated over a 40-year
- 8 period, the expected life of the UMR equipment),
- 9 ▪ 50/50 debt-to-equity ratio with 9.9% return on equity and 4.1% weighted
- 10 average cost of debt,
- 11 ▪ 26% income tax,
- 12 ▪ 2% property tax, and
- 13 ▪ Discount rate of 6.92% for NPV calculation, based on DTE Electric's
- 14 currently approved pre-tax weighted average cost of capital of its total
- 15 capital structure.

16

17 **Q70. What are the results of the BCA analysis?**

18 A70. The NPV of revenue requirements for all customer segments supported by the TEP
19 are shown in the table below:

⁴⁹ Cost of energy is an annual weighted average for each customer segment. This is determined by multiplying the hourly load forecast for each customer segment by the corresponding hourly market locational marginal pricing forecast (aligned with 2022 IRP through 2042) to determine the total annual cost for that customer segment, and then that total cost is divided by the total energy consumed by that customer segment. Starting in 2043, cost of energy for all segments is assumed to grow at 2.5%.

Line
No.1 **Table 13 NPV Revenue Requirement of Proposed TEP Customer Segments**

2

Customer Segment	Customer Sub-Segments	NPV Revenue Requirement (\$ millions)⁵⁰
SFHs	LI Level 2	-15
MUDs	LI Level 2	+2
	Non-LI Level 2	-31
Public	DAC/rural on-route DCFC	+14
	All other on-route DCFC	-3
Fleet	Transit bus DCFC	-6
	School bus DCFC	+7
	Other DCFC	-5
	Other Level 2	-37
Supporting Functions		+17
Total		-56

3

4 Overall, the TEP portfolio-level BCA results in \$56 million of rate relief for DTE
5 Electric customers. The segment-level revenue requirement NPVs range from \$14
6 million in rate pressure for the DAC/rural on-route DCFC subsegment to \$37
7 million in rate relief for the other fleet Level 2 segment. The portfolio-level BCA is
8 the sum of the segment-level NPVs less the NPV of increased revenue requirement
9 for supporting functions that include E&O, program administration, additional
10 elements, and the emerging technology fund (approved in Case Number U-21297
11 for five years, starting in 2024, with a projected annual investment of approximately
12 \$1 million).

13

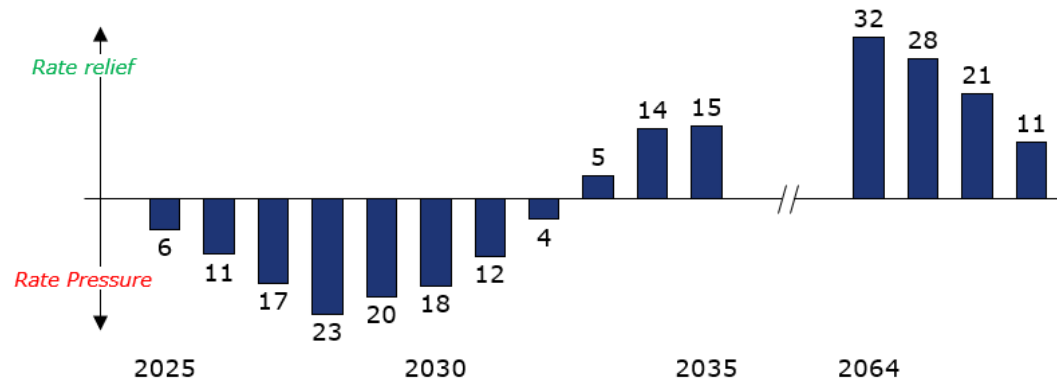
14 As shown in Figure 6 below, the annual revenue requirement initially applies rate
15 pressure, but the TEP begins providing rate relief in 2033, increasing to a maximum
16 of \$32 million of rate relief in 2064. So, while there is rate pressure in the near-term,

⁵⁰ For net revenue requirement, + means the sub-segment or portfolio is adding rate pressure whereas - means it is providing rate relief. See above for more detail.

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1 it is offset by future rate relief, making rebates beneficial for customers in the long
2 run.

3 **Figure 6 Annual Revenue Requirement from the 2025-2028 TEP**
4 **Investment (\$ millions)**



6
7 **Q71. What, in addition to the above discussion, should be considered when**
8 **reviewing the BCA results?**

9 **A71.** DTE Electric considers the \$56 million in rate relief, calculated as a result of the
10 proposed TEP investment using the BCA methodology described above, to be a
11 conservative estimate, for several reasons:

- 12 1. The BCA only considers incremental load from rebated chargers; it does not
13 take credit for any “network effects” of EV sales influenced by the TEP through
14 reduced range anxiety. In fact, as mentioned above, the “qualified” additional
15 EV load accounted for in the BCA is only about 10% of total expected EV load
16 through 2030,
- 17 2. As described previously, utilization rates are held constant over the life of the
18 electrical infrastructure serving the charger, despite likely increasing over time
19 as EV adoption grows, and

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1 3. The BCA does not take credit for any revenue generated in the first year of any
2 rebated charger's installation, despite rebated chargers coming online
3 throughout the year that the investment occurs.

4

5 **Q72. How will DTE Electric account for utility make-ready costs for all newly**
6 **installed EV chargers, regardless of participation in the TEP?**

7 A72. DTE Electric customers are expected to request new or upgraded service
8 connections to install chargers, even if they do not participate in a TEP program.
9 Based on the market assessment above, approximately \$189 million of utility make-
10 ready investment will be needed for utility make-ready work to connect the
11 chargers required to support EV adoption from 2024 through 2028. From this same
12 analysis, DTE Electric estimates that it will be responsible for approximately 85%
13 of this investment, following DTE Electric tariff and line extension policy, with the
14 balance coming from customers' CIAC. Therefore, the total non-CIAC UMR
15 investment of \$161 million has been included in the new customer connection
16 portion of the budget of DTE Electric's 2023 Distribution Grid Plan (DGP) for the
17 DGP investment timeframe of 2024 through 2028 (filed September 29, 2023, in the
18 Case No. U-20147 docket). Non-CIAC UMR costs, for all new or upgraded service
19 connections to install chargers, for the bridge year of 2024 (\$4.7 million) and the
20 test year of 2025 (\$11.4 million) are included on page 5 , line 29 of Schedule B5.4
21 of Exhibit A-12.

22

23 IV. TEP Expense

24 **Q73. What costs and accounting treatment is DTE Electric requesting for rate**
25 **recovery in this proceeding associated with the TEP?**

Line
No.

1 A73. TEP costs and accounting treatment the Company requests in this proceeding
2 associated with the TEP are summarized in the table below:

3

4 **Table 14 Projected TEP Program Spend in 2025 by Accounting Treatment (\$,**
5 **in thousands)**

6

Program Component	Accounting Treatment			Totals
	Capital	O&M	Regulatory Asset	
Program Administration		1,752		1,752
Education & Outreach		1,500		1,500
Business and eFleet Charger Rebates (public, fleet and MUD segments)			16,002	16,002
Residential Customer Rebates (low-income single family homes only)			3,126	3,126
Emerging Tech Fund			1,000	1,000
TEP IT Capabilities	1,600			1,600
Total Program Spend	1,600	3,252	20,128	24,980

7

8 **Q74. What are the costs for Education & Outreach?**

9 A74. As the new fuel provider for EVs and to build off early success, the Company
10 proposed EV E&O as a permanent offering in Case Number U-21297, and the
11 Commission approved \$1.5 million, as shown in Exhibit A-12, Schedule B5.9, line
12 11, column (f), on an ongoing basis for these efforts. Over 90% of surveyed
13 stakeholders agreed that continued E&O as part of the TEP was either “important”
14 or “extremely important” and nearly 60% responded the same for the eFleet
15 Advisory Service, with the balance remaining “neutral” in both cases.

16

17 As its E&O efforts mature with the TEP in 2025, DTE Electric intends to roll eFleet
18 Advisory Services under the ongoing E&O umbrella. The Company will also

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1 explore a similar service for MUDs, to ease the charger installation process for
2 landlords. This service would partially address coordination issues stemming from
3 landlords and Homeowners Associations not pursuing or allowing charger
4 installations because they do not understand the incentives available or the
5 installation process.

6

7 **Q75. What are the costs for program administration?**

8 A75. Similar to E&O, the Company proposed a permanent EV team in Case No. U-21297
9 and received approval in the December 1, 2023 Order. A permanent DTE Electric
10 EV team will provide continuous, stable, and high-quality TEP administration and
11 execution. Annual program administration costs for the TEP time frame are
12 estimated to be about \$1.8 million, as shown in Exhibit A-12, Schedule B5.9, line
13 12, column (f), to support labor costs for the EV team and program costs, such as
14 EV industry knowledge sharing and the web-based rebate application subscription
15 from PowerClerk®. The team will be responsible for everything from strategy to
16 program execution, including facilitating EV-related federal funding opportunities
17 for Southeast Michigan, as applicable.

18

19 **Q76. What are the costs for the Emerging Technology Fund?**

20 A76. As approved in Case No. U-21297, the \$1 million annual Emerging Technology
21 Fund allows the Company to efficiently test new technologies and prepare for
22 widespread EV adoption in the future. The Company launched an annual grant
23 program to enable timely funding of prudent pilots in a rapidly evolving technology
24 environment. Organizations seeking funding are vetted via three stages of review:
25 initial screening by the EV team, cross-functional review by other business units

Line
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1 within DTE Electric, and the final review by the Emerging Technology Fund
2 Advisory Committee that was established in March 2023.⁵¹ Each year, the Advisory
3 Committee convenes multiple times a year for rounds of reviews until the \$1
4 million funding is exhausted for deserving proposals. Line 21 of Exhibit A-12,
5 Schedule B5.9 shows \$1.0 million in test period costs in column (f).

6

7 **Q77. What are the costs for TEP IT capabilities?**

8 A77. The Company is proposing an information technology investment of approximately
9 \$1.6 million, as shown in Exhibit A-12, Schedule B5.9, line 8, column (f), to build
10 data capabilities and dashboards for the purpose of tracking and reporting. This is
11 the majority of the approximate \$2.5 million that DTE Electric estimates will be
12 necessary to fully support the TEP programs during their four-year timeframe. This
13 is approximately 2% of the total proposed rebates, which is in alignment with, and
14 in some cases, even below, the benchmarked TEPs. Please see above for details on
15 metrics proposed to be tracked.

16

17 **3. Customer Collection – Merchant Fees**

18 **Q78. What is the purpose of your testimony regarding merchant fees?**

19 A78. The purpose of my testimony regarding merchant fees is to support the recovery of
20 debit and credit card payment transaction fee expenses in the Company's rates.

21

22 **Q79. What are merchant fees?**

⁵¹ Members include Ecology Center, EPRI, Ford, GM, the MPSC, and Next Energy

Line
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1 A79. Merchant fees are the transactional costs associated with the processing of debit
2 and credit card payments. These costs, or fees, are expenses borne by the Company
3 and levied by the customer's debit and credit card issuer and payment processor.
4

5 **Q80. What type of debit and credit cards does the Company allow customers to use?**

6 A80. DTE Electric allows the use of all debit cards for bill payments. In addition, it
7 allows customers to use Visa, Discover, or MasterCard credit cards. DTE Electric
8 has restricted the type of credit cards that are allowed for bill payment to these three
9 card issuers as they offer a lower negotiated utility transaction rate for customers
10 using consumer credit cards.
11

12 **Q81. How many DTE Electric customers used credit or debit cards as a form of**
13 **payment over the last five years?**

14 A81. The number of customers using the debit or credit payment option one or more
15 times in a given year is shown in the table below. It has increased by 13% over the
16 last five years, from less than 1.0 million in 2018 to over 1.1 million in 2022.
17

18 **Table 15 Number of DTE Electric Customers paying with a Credit/Debit Card**

19 **2018-2022**

20

	2018	2019	2020	2021	2022
Residential	985,417	1,047,404	1,060,122	1,092,245	1,112,592
Non-Residential	34,707	37,480	38,518	39,863	41,173
Total	1,020,124	1,084,884	1,098,640	1,132,108	1,153,765

21

22 **Q82. What is the average monthly merchant fee paid by the Company?**

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1 A82. The average monthly customer merchant fee paid by the Company for residential
2 and non-residential customers in 2022 was \$0.94 and \$4.72, respectively.

3

4 **Q83. What measures has the Company taken to minimize merchant fees?**

5 A83. DTE Electric continues to restrict the use of debit and credit cards for business
6 customers with two mitigation policies that were proposed and approved by the
7 Commission in prior rate cases:

8 1. In Case No. U-20162, the Company proposed excluding industrial customers on
9 rate schedules D6.2, D8, D10, and D11 from using debit or credit cards (“Rate
10 Blocking”, implemented August 2019), and

11 2. In Case No. U-20561, the Company proposed limiting the use of debit and credit
12 card payments to commercial and industrial (“C&I”) customers whose aggregate
13 annual energy bill in the preceding calendar year was less than \$75,000 (“Annual
14 \$75K Blocking”, implemented January 2021.)

15 **Q84. How many DTE Energy customers were restricted from using a debit or credit
16 card over the last five years?**

17 A84. All customers are provided the opportunity to use a debit or credit card as a form
18 or payment, with the exception of those customers associated with the two cost
19 mitigation strategies described above. The number of customers restricted based on
20 those two cost mitigation strategies over the last five years is shown in the table
21 below:

Line
No.1 **Table 16** **Total DTE Customers Restricted from Credit/Debit Card Payments⁵²**

2

	2019	2020	2021	2022	2023
Rate Blocking	271	243	191	164	116
\$75K Blocking	-	-	5,328	5,238	5,882
Total	271	243	5,519	5,402	5,998

3

4 **Q85. How have the non-residential cost mitigation strategies curtailed merchant fee**
5 **expense?**

6 A85. From 2016 to 2018, non-residential merchant fee expenses grew 50%, increasing
7 from \$2.1 million in 2016 to \$4.7 million in 2018. From 2019 to 2022, non-
8 residential merchant fee expense decreased by 22%, from \$5.4 million in 2019 to
9 \$4.2 million in 2022, as shown in line 3 of Exhibit A-13, Schedule 5.7.1, page 2,
10 columns (b) and (e), respectively. The reduction in non-residential merchant fees
11 since 2019 is attributed to the implementation of the two cost mitigation strategies
12 described above.

13

14 **Q86. What does the Company forecast for merchant fees in the projected test**
15 **period?**

16 A86. The Company forecasts and seeks recovery of \$12.29 million for merchant fees in
17 the projected test period, as shown in line 5 of Exhibit A-13, Schedule C.5.7.1, page
18 1, column (g).

19

20 **Q87. How did the Company develop the merchant fee forecast?**

⁵² The blocked customers include DTE Gas customers in the totals since this is not separated in the reporting system.

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1 A87. The Company calculated a 2023 forecast, as shown in Exhibit A-13, Schedule
2 C5.7.1, page 2, column (g), line 4, from September 2023 year-to-date actuals and
3 three months forecast. As described above, total merchant fees have decreased in
4 recent years due to the non-residential cost mitigation strategies implemented in
5 2019 and 2021. However, now that both strategies have been in effect for over one
6 year, the Company anticipates merchant fees to level off in 2023 and not further
7 decrease. The two-year customer count growth of 0.5% was applied to the total
8 2023 merchant fee expense in column (g) to develop the 2024 and 2025 forecast,
9 as shown in columns (h) and (i), line 4 of the same exhibit.

10

11 **Q88. How did the Company calculate the customer count growth rate?**

12 A88. The company used the 2023, 2024 and 2025 customer counts in Exhibit A-15,
13 Schedule E6, page 1, as detailed in the table below, to calculate the growth rate
14 used to forecast 2024 and 2025 merchant fees.

15

16 **Table 17 Customer Count Growth Percentage Calculation**

17

Customer Type	Column (s)	2023 (Line 6)	2024 (Line 7)	2025 (Line 8)	2 Year Growth
Residential	(b)	2,055,641	2,064,797	2,074,827	0.5%
Non-Residential	(c) to (e)	215,031	216,100	217,086	0.5%

18

19 **4. Advanced Customer Pricing Pilot and Full Time of Day Rollout**

20 **Q89. What is the role of evaluation, monitoring and verification (EM&V) in the**
21 **Advanced Customer Pricing Pilot Program (ACPP) for 2022 and the amount**
22 **sought for recovery?**

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1 A89. The role of EM&V during the ACPP pilot supported administering participant
2 surveys and ensuring that evaluation and analysis of this data to provide
3 compelling, comprehensive and insightful information as the Company progressed
4 toward a full TOD rollout. Information included optimal communication channels
5 to reach customers, the most useful tools to provide (such as on-peak/off-peak
6 usage graphs on the website), and content most impactful for the welcome kit (such
7 as tips to save energy on the new rate). As shown in line 5 of Exhibit A-13, Schedule
8 C5.9.2, column (e), DTE Electric is seeking to recover \$0.172 million of O&M
9 expenses related to EM&V. Authorization to defer ACPP project costs to a
10 regulatory asset was provided in Case No U-20162.

11

12 **Q90. What is the role of Customer Outreach in the full TOD rollout?**

13 A90. Customer Outreach communicated the transition to full TOD rollout to ensure that
14 all residential electric customers were informed that their base rate would be
15 changed to a new TOD rate in March 2023.

16

17 **Q91. What is the total O&M expense for Customer Outreach that DTE Electric is**
18 **seeking to recover?**

19 A91. DTE Electric is seeking to recover \$2.497 million of O&M expenses related to
20 Customer Outreach for the full TOD rollout. The calendar year 2022 expenses are
21 \$2.044 million and 2023 expenses are \$0.453 million. As explained further by
22 Witness Uzenski, these expenses have been approved by the Commission for
23 deferral and amortization over a period that includes the projected periods in this
24 proceeding, as detailed on Exhibit A-13, Schedule C5.9.2, line 10.

25

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1 **Q92. Why is \$2.497 million of O&M expense needed for Customer Outreach?**

2 A92. Based on lessons learned from the Advanced Customer Pricing Pilot, DTE Electric
3 prepared customers for the upcoming change in their rate by sending a series of
4 communications via multiple channels. The majority of communications were sent
5 prior to the full TOD rollout in March 2023 and informed and educated customers
6 about their new rate and provided tips for savings on a TOD rate. The Company
7 conducted message testing with research and focus groups to ensure that all
8 communications developed were both easy to understand and engaging. The
9 Company also produced the following two videos as part of its outreach strategy:

- 10 • What a customer needs to understand about the new rate; and
- 11 • How to save money on the new rate by shifting usage to non-peak times and
- 12 tools to help manage usage.⁵³

13

14 **5. Electric Regulated Marketing Operations & Maintenance Expense**

15 **Q93. What does Electric Regulated Marketing O&M expense include?**

16 A93. Electric Regulated Marketing O&M expense includes the following areas:

- 17 ▪ Major Account Services, which manages new and existing customer
- 18 relationships for C&I customer classes,
- 19 ▪ Electric Marketing, which manages marketing campaigns to educate
- 20 customers, develops new product and service offerings, and performs project
- 21 management,
- 22 ▪ Economic Development, which seeks to stimulate local economic growth
- 23 and activity, including job growth through business attraction and expansion,

⁵³ Video on how to save money on the new rate - Time of Day 3 p.m. - 7 p.m. | Products | DTE Energy, available at <https://solutions.dteenergy.com/dte/en/Products/Time-of-Day-3-p-m---7-p-m-/p/TOD-3-7>, accessed on January 5, 2024

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- 1 ▪ The Demand Response Portfolio costs, supported by Company Witness
- 2 Farrell
- 3 ▪ Charging Forward O&M expense, explained above, and
- 4 ▪ Amortization of the Charging Forward regulatory assets, supported by
- 5 Company Witness Uzenski.

6

7 **Q94. What are the Electric Regulated Marketing O&M expenses for the historical**
8 **period?**

9 A94. As shown in line 15 of Exhibit A-13, Schedule C5.9, column (e), Electric Regulated
10 Marketing total O&M expense for the adjusted 2022 historical test period was \$20.5
11 million.

12

13 **Q95. What is the total Electric Regulated Marketing O&M expense for the**
14 **projected test period that DTE Electric is seeking to recover?**

15 A95. As shown in line 15 of Exhibit A-13, Schedule C5.9, column (k), DTE Electric is
16 seeking to recover \$32.2 million of Electric Regulated Marketing O&M expense in
17 the projected test period.

18

19 **Q96. What is driving the change between the historical period and the projected test**
20 **period?**

21 A96. DTE Electric is proposing an increase of \$11.62 million based on the following
22 changes to the historical 2022 Electric Marketing O&M expense.

- 23 1. EV Program O&M expense of \$3.25 million, as shown in column (i), line 10 of
- 24 Exhibit A-13, Schedule 5.9;

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- 1 2. \$2.96 million related to Demand Response (“DR”) programs, as supported by
2 Company Witness Farrell and shown in line 9 of the same exhibit;
3 3. Charging Forward regulatory asset amortization of \$3.51 million, as supported
4 by Company Witness Uzenski and shown in line 11 of the same exhibit; and,
5 4. Inflation for 2023, 2024 and 2025 in the amount of \$1.9 million, as shown in
6 columns (f) through (h), line 15 of the same exhibit.

7

8 The majority of the increase (\$6.8 million) is driven by the Company’s EV
9 programs, which are either proposed in this case and justified above (\$3.25 million)
10 or already approved in prior cases and seeking regulatory asset amortization (\$3.51
11 million). Another \$2.96 million of the increase is due to demand response programs
12 and justified in the instant case by Company Witness Farrell.

13

14 The remaining \$1.89 million is based on assumed labor and material annual inflation
15 adjustment factors of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025, as
16 supported by Company Witness Uzenski.

17

18 **Q97. What are your conclusions regarding the level of Electric Regulated**
19 **Marketing O&M expense for the projected test period?**

20 A97. The Electric Regulated Marketing O&M expense is reasonable, prudent, and
21 necessary to support the programs proposed by the Company in the instant case, to
22 maintain the existing level of customer support to C&I Major Account Services
23 customers, to support the Company’s economic development activities, and to
24 educate all customers on Company offerings.

25

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1 **Q98. What are your thoughts on the level of DTE Electric's historical and projected**
2 **capital, regulatory asset, and O&M expenses contained in your testimony,**
3 **overall?**

4 A98. DTE Electric has been reasonable and prudent in past capital and O&M expenses,
5 and I anticipate this to continue through the projected test period and beyond. I
6 believe that DTE Electric has fully justified, as reasonable and prudent, its request
7 for capital, regulatory asset, and O&M expenses that are set forth in my testimony
8 and associated exhibits.

9

10 **Q99. Does this complete your direct testimony?**

11 A99. 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	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
<u>for miscellaneous accounting authority.</u>	)	

REBUTTAL TESTIMONY

OF

PINA BENNETT

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF PINA BENNETT

Line
No.

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

3 A1. My name is Pina Bennett (she/her/hers). My business address is: One Energy Plaza,
 4 Detroit, Michigan 48226. I am employed by DTE Electric Company as Director,
 5 Electric Marketing.

6

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

9 A2. Yes.
 10

11 **Purpose of Testimony**

12 **Q3. How is your testimony organized?**

13 A3. My testimony will address various recommended changes from multiple parties
 14 with respect to the Company's electric vehicle (EV) proposals and Merchant Fees.
 15 Collectively, my rebuttal testimony will address direct testimony from the
 16 following parties:

- 17 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 18 Witnesses Freeman, and Revere.
- 19 • Attorney General (AG) Witness Coppola;
- 20 • Michigan Environmental Council (MEC), Natural Resource Defense
- 21 Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan
- 22 (CUB) (collectively MNSC) Witness Jester
- 23 • AG-MN (MEC and NRDC) Alvarez and Stephens;
- 24 • Michigan Energy Innovation Business Council, Institute for Energy
- 25 Innovation, and Advanced Energy United (MEIU) Witness Dr. Sherman;

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- 1 • City of the Ann Arbor (AA) Witness Stults;
- 2 • Electrify America LLC. Witness Shah and Davis; and
- 3 • EVgo Witness Stegall;
- 4

5 **Q4. What is the purpose of your rebuttal testimony?**

6 A4. There are 14 specific topics I will rebut in this testimony, as listed below. Unless I
7 explicitly state agreement, I will provide a detailed discussion of why the
8 intervenor's recommendations should not be accepted.

9

10 **Charging Forward**

- 11 1. Applications and Awards from Federal EV programs;
- 12 2. School Bus Charger Program update;
- 13 3. Charging Hubs update;
- 14 4. Emerging Technology Fund update;
- 15 5. Reallocation of Funds; and
- 16 6. EV Forecast
- 17

18 **Transportation Electrification Plan (TEP)**

- 19 7. Charger Uptime Requirements;
- 20 8. Destination Charging;
- 21 9. Residential Program;
- 22 10. Public Level 2 Chargers;
- 23 11. Fleet Rebates for Schools;
- 24 12. Contribution In Aid of Construction (CIAC) Waiver; and
- 25 13. Benefit Cost Analysis (BCA) for TEP.

Line
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1 **Credit and Debit Card Merchant Fees**

2 14. Credit and Debit Card Merchant Fees

3

4 The absence of a discussion of other matters in my testimony should not be taken
5 as an indication that I agree with all other aspects of intervenor testimony. My
6 testimony instead focuses on high priority issues and responses to the positions of
7 these parties.

8

9 **Q5. Are you sponsoring any exhibits in this proceeding?**

10 A5. Yes. I am sponsoring the following exhibits:

11	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
12	A-49	NN1	Rebuttal Freeman Disallowance Residential and
13			Business Charger Rebates
14	A-49	NN2	Charging Forward Capital Expenditures
15	A-49	NN3	U-21534 EVgoDTE-1 Discovery Response
16	A-49	NN4	U-21534 AGDE-4.149c Discovery Response
17	A-49	NN5	U-21534 Discovery Responses EV Forecast

18

19 **Q6. Were these exhibits prepared by you or under your direction?**

20 A6. Yes, they were.

21

22 **Charging Forward**

23 **Q7. What is your impression of how Charging Forward is perceived by all**
24 **intervenors?**

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1 A7. There generally appears to be support for Charging Forward. Six witnesses have
2 made some suggestions, which I address below.
3

4 **Topic 1: Rebuttal to Applications and Awards from Federal EV Programs**

5 **Q8. How do you respond to Staff Witness Freeman's suggestion to supply a list of**
6 **the federal EV programs the Company has applied for and been awarded in**
7 **its next rate case (page 9, lines 19-20)?**

8 A8. The Company will provide, in the Company's next rate case, a list of the federal
9 EV programs the Company has directly applied for and been awarded.
10

11 **Topic 2: Rebuttal to School Bus Charger Program Updates**

12 **Q9. How do you respond to Staff Witness Freeman's recommendation for the**
13 **Company, in its next rate case, to discuss in detail its School Bus Charger**
14 **program and share any initial results from the program? (Page 5, lines 4-6)**

15 A9. While I believe DTE Electric has generally kept stakeholders well-informed of the
16 School Bus Charger program, the Company does file an annual EV status update
17 report and will make a point of updating the Commission on the status of the School
18 Bus Charger program, in particular, in its next EV Annual Status Report.
19

20 **Topic 3: Rebuttal to Charging Hubs**

21 **Q10. How do you respond to Staff Witness Freeman's request to provide a detailed**
22 **explanation on the progress of the Company's Charging Hub (page 5, lines 8-**
23 **19)?**

24 A10. The Company's Charging Hub pilot was designed to facilitate fleet electrification
25 by offering multiple fast chargers and pull-through spaces for heavy-duty and larger

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1 vehicles at a single location. DTE Electric was approved to spend \$2.8 million in
2 Case No. U-20836 to build, own, and operate up to two Charging Hubs and
3 encouraged by the Commission in Case No. U-21297 to pursue all available state
4 and federal funding for the project. After evaluating various sites, DTE Electric
5 backed a grant application for a hub in Southeast Michigan. In February 2023, DTE
6 Electric collaborated with the State of Michigan's Office of Future Mobility and
7 Electrification (OFME) and Daimler Truck North America (DTNA) to apply for a
8 grant for a Charging Hub in Redford, Michigan. The application was bolstered by
9 more than ten letters of support from local businesses and stakeholders. In June
10 2023, an \$8.5 million Rebuilding American Infrastructure with Sustainability and
11 Equity (RAISE) grant for the build out of the Truck ¹ Stop of the Future was granted
12 to OFME. The State's legislative spending authority process is such that the grant
13 money cannot be used or used in anticipation until the grant is signed. The grant
14 can only be signed upon final budget approval. This has led to an estimated six-
15 month delay on the project. DTE Electric has been working with the project
16 partners to execute agreements that define roles and responsibilities, the scope of
17 work, and other financial and operational details, as set forth by Witness Peterson
18 in her testimony in Case No. U-21297 (page 47, lines 5-15). The project team
19 expects to launch a Request for Proposal for the site design and engineering by the
20 end of 2024 and to begin construction on the site in 2025. Given the collaborative
21 nature of the project with the involvement of multiple state and commercial entities,
22 I agree to provide a Charging Hubs update in the Company's EV Annual Status
23 Report.

¹ [State of Michigan partners with Daimler Truck North America and DTE Energy to build Michigan's 'truck stop of the future' | Michigan Business](https://www.michiganbusiness.org/press-releases/2023/06/daimler-dte/) available at <https://www.michiganbusiness.org/press-releases/2023/06/daimler-dte/>

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1 **Topic 4: Rebuttal to Emerging Technology Fund (ETF) Progress**

2 **Q11. What is your reaction to Staff Witness Freeman's request to provide a report**
3 **on the results of the initial awards from the Company's Emerging Technology**
4 **Fund in its next rate case and yearly thereafter (page 10, line 3-4 and page 7,**
5 **lines 2-6)?**

6 A11. I believe the Company is already effectively doing so, as stated in my direct
7 testimony in this case on page 51, rows 21-22, by committing to providing Annual
8 Status Reports for its TEP programs.

9
10 **Topic 5: Rebuttal to Reallocation of Funds**

11 **Q12. How do you respond to EVgo Witness Stegall (page 15 line 20 through page 16**
12 **line 10 and page 19 lines 10-13) suggesting the Company reallocate any funds**
13 **remaining from the existing Business Charger Rebate program on December**
14 **31, 2024 into the non-DAC/rural subsegment of the proposed Business**
15 **Charger Rebate program?**

16 A12. I appreciate Witness Stegall's interest in seeing the funds reallocated. As stated in
17 my response (U-21534 Exhibit A-49 Schedule NN3 EVgoDTE-1.1c Discovery
18 Response), there are 149 sites and 593 in the pipeline to receive funding through
19 DTE Electric's Business Charger Rebate program. Given the popularity of the
20 program, as acknowledged by Witness Stegall (page 7, lines 20 through page 8, line
21 1), DTE Electric could first hold funds for any customer who has already applied
22 prior to December 31, 2024 and whose projects are showing progress to protect
23 customers who are in the process of making these large investments. If there is
24 funding remaining after this, the Company is open to reallocating the remaining

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1 funding into the non-DAC/rural subsegment of the proposed Business Charger Rebate
2 program, should there be no significant opposition from other stakeholders.

3

4 **Topic 6: Rebuttal to EV Forecast**

5 **Q13. What are the views on the forecast adoption of EVs presented by various**
6 **witnesses?**

7 A13. Two witnesses shared their opinions on the EV forecast presented by the Company
8 that was used for planning in this instant case. MEIU Witness Sherman asserts on
9 page 16, lines 4-13 that the forecasted EV deployment used by the Company in this
10 case is likely too low. Conversely, AG Witness Coppola, while not directly
11 addressing the Company's forecast, suggests on page 25 lines 1-18, and page 26,
12 lines 1-12, that the market for EVs is less than what the Company projects, and
13 therefore the Company does not need to make certain investments to accommodate
14 future growth in EVs.

15

16 **Q14. What is MEIU Witness Sherman's opinion on the EV sales forecast?**

17 A14. Witness Sherman agrees with the underlying methodology the Company used to
18 forecast EVs, however she asserts that some of the inputs may be incompatible due
19 to recently adopted Federal vehicle emissions standards from the EPA that she cites.
20 Specifically, on page 16, lines 5-13 of her testimony, Witness Sherman states that
21 "This is procedurally reasonable but on examination, two of the six forecasts
22 utilized projected national EV sales that are too low to be compatible with recently
23 adopted Federal vehicle emission standards, which the U.S. Environmental
24 Protection Agency ("EPA") characterized as based on EVs being 30 to 56 percent

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1 of light duty vehicle sales by 2032. It is therefore likely that the Company's EV
2 sales forecast is too low."

3

4 **Q15. How do you respond to Witness Shermans assertions?**

5 A15. I have several concerns. First, Witness Sherman's citation from the EPA includes
6 the following quote: "EPA projects that for manufacturing years 2030-2032
7 manufacturers may choose to produce battery electric vehicles (BEVs) for about 30
8 percent to 56 percent of new light-duty vehicles sales and about 20 percent to 32
9 percent of new medium-duty vehicle sales." The quote from the EPA is, like other
10 forecasts, an opinion on their expectations of the market. While the EPA is a
11 credible source, the Energy Information Administration (EIA), a statistical division
12 of the Department of Energy, projects 16% of new vehicle sales will be electric by
13 2032², which further highlights the reason the Company relies on multiple sources
14 to conduct its forecast. Additionally, the 2032 expectation that Witness Sherman
15 relies on to assert the sales forecast is too low is beyond the time period range of
16 the planning done for this instant case, as well as the Company's TEP which goes
17 through 2028.

18

19 **Q16. How does AG Witness Coppola characterize the market for EVs?**

20 A16. On page 25 line 4 through page 26 line 4, Witness Coppola states "During the first
21 six months of 2024, EV manufacturers have realized that electric vehicles are not
22 selling at the pace anticipated as late as 2023 and EVs are stockpiling at dealers'

² U.S. Energy Information Administration - EIA - Independent Statistics and Analysis available at <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.62-48-AEO2023.1-0~ref2023-d020623a.63-48-AEO2023.1-0~ref2023-d020623a.67-48-AEO2023.1-0&map=ref2023-d020623a.4-48-AEO2023.1-0&ctype=linechart&sourcekey=0>

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1 lots. EV buyers often have been dissatisfied with the actual driving range,
2 particularly during the winter and hot days that quickly drain the car batteries.
3 Reliability of certain vehicles with recalls for software and equipment failures has
4 also created customer dissatisfaction and increased concerns and fear with
5 prospective EV buyers. EV manufacturers have cut back production of EVs,
6 delayed new models, deferred building new batteries plants, and redirected
7 resources to hybrid vehicles with batteries that self charge during gasoline-fueled
8 operation. The current environment and demand for EV does not support the
9 increase in spending forecasted by the Company for 2024 and 2025 for UMR. With
10 EV adoption currently waning, I propose that the 2024 and 2025 capital
11 expenditures for UMR be set at the 2023 amount plus inflation.” He further states
12 on page 55 (lines 6-9) that “...consistent with my recommendations in the Utility
13 Make Ready testimony, I propose that the forecasted capital expenditures in
14 Schedule B5.9 [EV Charging Forward] be reduced by 45% for 2024 and 2025...”
15 Ultimately, these statements result in Witness Coppola recommending that the
16 Company be disallowed various investments on the basis that EV adoption will not
17 occur at the pace the Company expects it to.

18

19 **Q17. Do you agree with the way Witness Coppola characterizes the EV market and**
20 **that EV adoption may not materialize at the rate the Company has proposed?**

21 A17. No. I disagree with Witness Coppola’s characterization. There is ample evidence
22 to support the Company’s projections of EVs that were used as the basis for various
23 investments in this instant case. Witness Coppola characterizes the EV market in a
24 way that makes it seem like the EV market is in decline, but this is not true. EV
25 adoption is still growing, even if at a slower pace than prior projections, with

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1 external analysts projecting that as affordability in the mass market segment of EVs
2 improves, adoption will follow³. In several discovery responses requested by the
3 AG (U-21534 Exhibit A-49 Schedule NN5), the Company responded that year-to-
4 date in 2024 EV sales experienced their highest levels on record in the state of
5 Michigan, demonstrating continued growth, not decline, in the EV market.

6

7 Furthermore, the Company's forecast is on track as it pertains to accuracy. The
8 Company is projecting over 22,000 new electric vehicles to enter the Service Area
9 in 2024, which through five months of 2024, the market is on track to achieve, as
10 seen in Table 1.

11

Table 1: 2024 EV Registrations

Month	Count of Registrations
January	1,240
February	1,567
March	1,772
April	2,234
May	2,603
Monthly Average	1,883
Annualized (1,883 x 12)	22,596

12

13 As it pertains to the number of EVs the Company is forecasting, the Company
14 believes the projections presented in this instant case are conservative, and
15 reflective of the realized pace of EV adoption. For reference, the Michigan MI

³ [J.D. Power-GlobalData Automotive Forecast July 2024 | J.D. Power \(jdpower.com\) available at https://www.jdpower.com/business/press-releases/jd-power-globaldata-automotive-forecast-july-2024](https://www.jdpower.com/business/press-releases/jd-power-globaldata-automotive-forecast-july-2024)

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1 Healthy Climate Plan⁴ targets 50% of new vehicle sales being electric by 2030.
2 Additionally, as stated above, MEIU Witness Sherman suggests EVs could make
3 up 30%-56% of new vehicle sales by 2032. Both the MI Healthy Climate Plan goal,
4 and the midpoint of the range opined on by Witness Sherman are likely higher than
5 what the Company's forecast is on pace to achieve at 22% of new vehicles being
6 electric by 2028.

7

8 **Q18. How do you respond to AG Witness Coppola's proposed capital disallowances**
9 **of \$7 million in 2024 and \$2.3 million in 2025 related to the EV Charging**
10 **Forward Program? (page 55, lines 6-9)**

11 A18. I disagree. As discussed earlier in my testimony, the Company has developed
12 reasonable projections in its EV forecast. Witness Coppola's recommendation to
13 reduce the EV Charging Forward capital spend by 45% based on a slower EV
14 adoption expectation should be rejected.

15

16 **Q19. What are your thoughts with respect to AG Witness Coppola's proposed**
17 **disallowance of 2024 and 2025 capital expenditures for utility make ready**
18 **(UMR) associated with EVs by setting such UMR expense at the 2023 amount**
19 **plus inflation due to an expectation of lower attachments based on the EV**
20 **forecast (pages 24-26)?**

21 A19. I disagree. The Commission should find that the Company's EV forecast presented
22 in this instant case is reasonable and appropriately reflects expected EV adoption
23 over time. Both the UMR expense I utilize and the Company's EV adoption
24 forecast are reasonable projections. Therefore, Witness Coppola's conclusion that

⁴ [MI Healthy Climate Plan \(michigan.gov\)](https://www.michigan.gov/healthyclimate)

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1 EV adoption is “currently waning” and recommendation to disallow \$3.7 million
2 in 2024 and \$10.2 million in 2025 of project expenditures associated with EV-
3 related UMR should be rejected.

4

5 **Q20. How do you respond to AG-MN Witness Stephen’s recommendation for an**
6 **independent expert analysis of the EV adoption forecasts (page 23, lines 17**
7 **through 20)?**

8 A20. The Company strongly disagrees with Witness Stephen’s recommendation for an
9 independent expert analysis of the EV adoption forecasts. The Company has based
10 its forecast analysis on expert external forecasts which are conducted by reputable
11 organizations with extensive experience and expertise in the field. These forecasts
12 are often based on comprehensive data and sophisticated models, making them
13 reliable sources of information. Additionally, the Company adjusts these forecasts
14 for local conditions in Michigan and its service territory. This means the forecasts
15 already take into account local factors such as the state’s economic conditions,
16 infrastructure, and policies related to EVs. Conducting an audit and independent
17 expert analysis would require significant resources, including time and money.
18 These resources could be better spent on other initiatives that directly support the
19 adoption of EVs, such as infrastructure development and customer education.

20

21 **Q21. What is your response to AG-MN Witness Alvarez’s testimony on page 20,**
22 **rows 11 through 13, indicating that about 95% of EV charging for customers**
23 **on time-of-use rates occurs off-peak?**

24 A21. The Company disagrees with Witness Alvarez’s assertion that about 95% of EV
25 charging happens off-peak. As referenced in my response to U-21534 Exhibit A-

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1 49 Schedule NN4 AGDE-4.149c Discovery Response , historical data up until
2 April 2024, shows that residential DTE Electric customers on the EV-specific rate
3 (D1.9), as well as those participating in the Home Charger Rebates pilot, had loads
4 that were below the AG's assertion at approximately 92% off-peak.

5
6 Additionally, it's important to note that not all EV owners will choose to participate
7 in the Company's programs and may opt to charge their vehicles at their
8 convenience. The report cited by Witness Alvarez rightly points out that "one
9 cannot conclude that these behavior patterns will hold as PEV technology matures,
10 charging technology and charging behaviors evolve, and PEVs achieve greater
11 market adoption beyond the early adopter phase." This suggests that as the EV
12 market matures and charging behaviors evolve, the Company may see a shift in
13 charging patterns. Therefore, it's crucial to consider this factor when planning for
14 future infrastructure and rate design.

15

16 **Transportation Electrification Plan (TEP)**

17 **Q22. What is your impression of how DTE Electric's TEP is perceived by all**
18 **intervenors?**

19 A22. There generally appears to be support for much of DTE Electric's Transportation
20 Electrification Plan by many intervenors. Eight witnesses also suggested limited
21 rejections or modifications to some of what the Company has proposed, which I
22 address below.

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1 **Q23. How do you respond to Staff Witness Freeman’s recommendation to disallow**
2 **\$8,000,000 for the Company’s Business and eFleet Charger Rebates program**
3 **(pages 8-9)?**

4 A23. I disagree with this recommendation (see Exhibit A-49 Schedule NN1 Rebuttal
5 Freeman Disallowance Residential and Business Charger Rebates). The
6 Company’s Business and eFleet Charger Rebates program for the TEP year 2025,
7 aims to support various segments, including low-income (LI) multi-unit dwellings
8 (MUDs), non-LI MUD, Public Disadvantaged Community (DAC)/Rural on-route
9 Direct Current Fast Chargers (DCFCs), other on-route DCFCs, and all fleet
10 segments. Compared to the 2024 Charging Forward levels, there’s a notable
11 increase in proposed rebate amounts per segment. For example, the average rebate
12 for low-income MUD customers is expected to be \$14,400, while DAC Public and
13 Fleet customer rebates for DCFCs are anticipated to average \$70,000. A reduction
14 in funding by \$8,000,000 would result in approximately 600 fewer rebates across
15 all proposed segments of the TEP.

16

17 **Q24. How do you respond to Staff Witness Freeman’s recommendation to disallow**
18 **\$1,000,000 for the Company’s Residential Customer Rebate program (pages**
19 **9-10)?**

20 A24. For the TEP year 2025, the Company’s Residential Customer Charger Rebates
21 program is designed to assist low-income single-family homes. This represents an
22 increase in the proposed rebate amounts compared to the 2024 Charging Forward
23 levels (see U-21534 Exhibit A-49 Schedule NN1 Rebuttal Freeman Disallowance
24 Residential and Business Charger Rebates). The average rebate is projected to be
25 \$2,200, on average, and will cover the cost of the charger and the full cost of

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1 installation; a substantial increase from the current levels of \$500 for Home Charger
2 Rebates and \$1,500 for EV Income Rebates. A funding reduction of \$1,000,000
3 would result in approximately 455 fewer rebates being available to support the
4 adoption of EVs for LI single-family home, therefore the Commission should reject
5 the recommendation.

6

7 **Q25. How do you respond to Witness Jester's reporting recommendations to**
8 **supplement the Transportation Electrification Plan with a forecast of load**
9 **profiles at line transformers, circuit feeder origination at the substation, and**
10 **at generation when electric vehicle charging is combined with existing loads at**
11 **various levels of electric vehicle adoption and by also providing an analysis of**
12 **load net of renewable generation at various levels of electric vehicle adoption**
13 **with Michigan attaining 50% renewables, 60% renewables, and 80%**
14 **renewables and to include full 8760-hour annual load profiles for electric**
15 **vehicle charging (pages 36 line 14 through page 37, page 43 lines 13-21 and**
16 **45)?**

17 A25. No, I do not agree. It poses challenges in terms of data availability, data cleaning
18 efforts, and potential misunderstanding of the data. For example, to the extent
19 public chargers are 1) not on a standalone meter and/or 2) not specifically known
20 to the Company to be a charger, the Company cannot at this time commit to the
21 granular and specific data being sought. While technology and data accessibility
22 improvements may support this requirement in the future, it would be difficult
23 today.

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1 **Topic 7: Rebuttal to Charger Uptime Requirements**

2 **Q26. How do you respond to the charger uptime statements from Electrify America**
3 **LLC. Witness Davis (page 4 through page 6 line 4)?**

4 A26. I acknowledge that charger reliability and network uptime information are
5 sensitive; the Company believes that charger uptime has to be measured to ensure
6 ratepayer funding is utilized most effectively. The 97% uptime target aligns with
7 Federal Highway Administration's (FHA) requirements, and the Company believes
8 these sites should have the same targeted reliability as National Electric Vehicle
9 Infrastructure (NEVI) EV sites, which will continue to fuel the growth of EV sales
10 in the Company's electric service territory. The Commission adopted the uptime
11 requirement in Case No. U-20836, where the Commission stated, "the Commission
12 adopts a 97% charger uptime for participants in this pilot as is currently proposed
13 by the FHA's NEVI program guidelines. Should the FHA ultimately revise or
14 update its guidance on uptime requirements upon issuance of the final NEVI rule,
15 the Commission would then be open to revisiting these guidelines and reserves the
16 right to modify this charger uptime requirement to maintain consistency with
17 federal guidelines." (Case No. U-20836 Order issued November 18, 2022, pp. 327-
18 331) I understand that many factors can impact an EV charger's uptime. Factors in
19 addition to charging equipment malfunctions such as, internet or cellular service
20 provider interruptions, outages caused by the vehicles, physical damage to the
21 charging equipment, and electric utility service interruptions can occur
22 unexpectedly, but the Charging Station Operator must be able to demonstrate that
23 the charging port would otherwise be operational. Furthermore, the Company's
24 TEP proposal does not propose to share any identifiable confidential and

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1 competitively sensitive uptime information from prospect site hosts receiving
2 rebates.

3

4 **Q27. How do you address Electrify America LLC. Witness Davis's (page 4 line 14**
5 **through page 6 line 4) concerns regarding the Company's participation**
6 **criteria requiring a "qualified, networked charger"?**

7 A27. The Company is open to collaborating with stakeholders on an alternate solution;
8 for example, to require a meter instead of qualified, networked chargers for
9 participating EV sites. This could potentially allow more charger providers to
10 participate and remove the burdensome process to onboard periodically qualified
11 Network Providers and requiring them to share monthly interval and session data.

12

13 **Topic 8: Rebuttal to Destination Charging**

14 **Q28. How do you respond to the recommendations from Electrify America LLC.**
15 **Witness Davis (page 6 line 15 through page 7 line 11), EVGo Witness Stegall**
16 **(page 13), and MEIU Witness Sherman (page 44) that propose to eliminate the**
17 **requirement that public DCFC must be "on-route" locations within one mile**
18 **of a major thoroughway to qualify for a rebate and instead extend these rebates**
19 **to all public DCFC locations?**

20 A28. I do not agree with Witness Davis, Witness Stegall, and Witness Sherman's
21 proposal to eliminate "on-route" locations within one mile of a major thoroughway
22 and instead extend rebates to all public DCFC locations. DTE Electric is committed
23 to supporting 35% of the forecasted on-route public charger deployment. The
24 funding is in alignment with stakeholders' priorities. Their ranking of all public
25 charging subsegments, including on-route and destination charging, as the most

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1 important for utility action, indicates their value on public charging in reducing
2 range anxiety. The provision of fast, reliable, on-route charging within one mile of
3 a major throughway exit is crucial in increasing customer confidence in EV
4 refueling infrastructure.

5

6 **Topic 9: Rebuttal to Residential Program**

7 **Q29. What is your stance on the proposal by both MEIU Witness Sherman (page 39**
8 **lines 3-5) and AA Witness Stults (pages 29 lines 10-17) that the residential**
9 **customer rebates program set the income-qualified threshold at 400%**
10 **(Sherman) or alternatively 300% (Stults) of the federal poverty level, for the**
11 **future?**

12 A29. As I have stated in my direct testimony (page 41), the Company had, in fact,
13 envisioned an income-qualified customer eligibility threshold of 400% of the
14 federal poverty limit. During the stakeholder engagement phase of the TEP
15 development, the Company received feedback from some stakeholders that this was
16 too high. Consequently, DTE Electric lowered the income eligibility threshold to
17 200% of the federal poverty limit, which also aligns with the threshold for other
18 DTE low-income programs⁵. Witness Sherman provides an example of
19 Southwestern Public Service Company, (SPS) and its inaugural TEP and asserts
20 that DTE Electric, given the restrictive income thresholds proposed for the Single
21 Family Home rebates, may similarly struggle to deploy LI rebates. I address this in
22 my direct testimony (page 42) that it will indeed be critical to monitor and adjust
23 the income eligibility threshold based on EV adoption to meaningfully support this

⁵ [Limited Income Assistance | DTE Energy – available at https://www.dteenergy.com/us/en/residential/save-money-energy/get-started-with/limited-income-assistance.html](https://www.dteenergy.com/us/en/residential/save-money-energy/get-started-with/limited-income-assistance.html)

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1 segment and encourage EV adoption in Southeast Michigan. Given that the
2 program was developed with stakeholder feedback in mind, the Company does not
3 deem it appropriate to modify the threshold without further participation data.

4

5 **Q30. Do you agree with MEIU Witness Sherman's recommendation on page 39**
6 **lines 5-8 to allow customers to self-attest to their income?**

7 A30. I do not. In the Company's experience administering the EV Rebate program, many
8 customers do not necessarily pay close attention to the eligibility criteria for a
9 program, instead relying on the Company to validate their eligibility. There is risk
10 involved with customer self-attestation when individuals with higher incomes
11 could potentially falsely claim to be low-income and take away resources from
12 those who truly need them. And while self-attestation might seem that it would
13 reduce administration burden, dealing with potential fraud and its consequences
14 could actually result in more administrative work for the Company in the long run.
15 Per my testimony (page 40), over 80% of the chargers needed between 2025 and
16 2028 are expected to be in the single-family home segment and the cost of installing
17 a home charger can be a significant barrier for low-income residential customers.
18 To ensure that the correct segment of customers benefits from this program, it is
19 necessary to have checks and balances in place to administer the program
20 accurately.

21

22 **Q31. What is your stance on MEIU Witness Sherman's recommendation on page**
23 **39 line 11 through page 41 line 9 that the residential TEP program qualify**
24 **customers on a location-based criteria as an alternative option to increasing**

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1 **the threshold for rebates to 400 percent of the federal poverty level, to ensure**
2 **meaningful support for LI households through this rebate segment?**

3 A31. As stated above, the Company intends to provide meaningful support for LI
4 households through this rebate segment and will monitor and adjust the income
5 eligibility threshold based on EV adoption and considering participation data.

6

7 **Q32. How do you respond to MEIU Witness Sherman's recommendation (pages 42**
8 **line 18 through page 43 line 7) that the requirement to demonstrate tenant**
9 **interest for the MUD-based charger programs is limited to a self-attestation?**

10 A32. I agree that this may be worth considering if there are also other reasonable
11 indications of legitimate charging demand. Some examples might include those
12 identified by the Company in discovery response MEIUDE-2.4a, which is also
13 Exhibit MEIU-21 (LSS-21). This would include tenant surveys, signed letters of
14 interest from tenants, pre-commitments from tenants, documents from past requests
15 for EV charging, or data on the number of tenants with EVs.

16

17 **Q33. What is your assessment of MEIU Witness Sherman's recommendation to**
18 **modify the Company's MUD rebate proposal?**

19 A33. Witness Sherman states on page 43 lines 11-12 of her direct testimony that for
20 MUDs that do not meet the Company's LI thresholds, the site host should be able
21 to use the full \$5,000 to pay for the charger and/or any make-ready costs. That is
22 exactly what the DTE Electric TEP is intended to accomplish. The Company
23 acknowledges that while landlords of MUDs that do not meet the LI eligibility may
24 have some incentive to install chargers as an amenity to attract tenants and retain
25 occupancy, coordination issues can still exist between landlords and tenants.

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1 Hence, the Company proposed to continue its support of this segment and raised its
2 current fixed rebate for other MUDs from \$2,000 to \$5,000 per Level 2 Charger.
3 Since the rebate is a fixed amount, the full \$5,000 is intended to be awarded to the
4 successful applicant to this rebate program.
5

6 **Topic 10: Rebuttal to Public Level 2 Chargers**

7 **Q34. What is your response to MEIU Witness Sherman's recommendation to make**
8 **rebates available for public Level 2 chargers (page 45 line 13 through page 47**
9 **line 10)?**

10 A34. Site hosts considering the installation of Level 2 chargers will find the economics
11 of deployment less challenging. These chargers utilize the standard 240V electrical
12 supply, which many businesses already have in place, making electrification cost-
13 effective. Beyond the financial aspect, businesses have additional motivations for
14 installation, such as the potential for increased foot traffic, even in the absence of
15 rebates. It is important to note that the majority of future charging needs are
16 expected to be met by DC Fast Chargers (DCFCs), due to their shorter charging
17 time, and therefore, we reject the recommendation to include rebates for public
18 Level 2 chargers at this time.
19

20 **Topic 11: Rebuttal to Fleet Rebates for Schools**

21 **Q35. What is your response to MEIU Witness Sherman's recommendation to offer**
22 **partial rebates to schools that do not utilize bi-directional chargers (page 48,**
23 **lines 7-8)?**

24 A35. As stated in my testimony (page 48 lines 14-16), the Company is proposing to
25 continue its eFleet Charger Rebate program for both school and transit buses with
26 a rebate of \$70,000 per DCFC, assuming 60 kW and 150 kW DCFCs for those

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1 subsegments respectively. The Company is open to considering Witness Sherman's
2 recommendation to offer partial rebates to schools that do not utilize bi-directional
3 chargers, and implement a charger output capacity tier- based rebate approach
4 similar to the existing Charging Forward eFleets Charger Rebates.

5

6 **Topic 12: Rebuttal to Contribution In Aid of Construction (CIAC) Waiver**

7 **Q36. Do you agree with MEIU Witness Sherman's assertion on pages 11 line 6**
8 **through page 12 line 5 of her direct testimony that make-ready programs are**
9 **different from policies that waive utility CIAC requirements for EV charging**
10 **stations?**

11 A36. No. It's essential to view make-ready programs and CIAC waiver policies, their
12 goals, and impacts, as complementary tools in the toolkit for promoting EV
13 infrastructure, rather than distinct, unrelated policies. Witness Sherman's argument
14 assumes that CIAC costs and make-ready infrastructure costs are entirely separate.
15 However, in reality, these costs are interconnected. The CIAC costs are part of the
16 total cost that a customer incurs when installing new public EV charging
17 infrastructure. Therefore, any program or policy that addresses one aspect of the
18 cost inherently impacts the other. Both make-ready programs and CIAC waiver
19 policies aim to reduce the financial burden on customers installing new public EV
20 charging infrastructure. They both contribute to the broader goal of promoting the
21 use of electric vehicles, therefore, the difference in their mechanisms does not
22 change their ultimate impact. Therefore, the Commission should not consider
23 Witness Sherman's recommendation on page 50, lines 5-9, to reject the Company's
24 proposal to eliminate the CIAC policy waiver.

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- 1 **Q37. How do you respond to Electrify America LLC. Witness Shah (page 6 lines 3-**
 2 **21) and MEIU Witness Sherman's (pages 11 line 17 through page 12 line 5)**
 3 **reaction to the Company's removal of its CIAC waiver policy?**
- 4 A37. DTE Electric's decision to align the CIAC policy for EV customers with other
 5 connections promotes fairness and equity, ensuring all customers contribute to the
 6 infrastructure they use. This decision also aims to provide positive rate impacts and
 7 keep rates affordable for all customers. The transition from a pilot to a permanent
 8 TEP necessitates this alignment for the program's sustainability. While cost
 9 certainty is important for Electrify America, it's also crucial for the Company and
 10 its customers to better manage costs and reduce risk. Despite the higher capital costs
 11 of developing DCFC sites, DTE Electric believes there are other ways to promote
 12 public charging infrastructure, such as partnerships, grants, and incentives. The
 13 implications of removing the CIAC waiver should be considered in the broader
 14 context. Over the past five years that DTE Electric has been running Charging
 15 Forward program, the CIAC waiver played a minimal to non-existent role⁶ (see
 16 Exhibit A-49 Schedule NN2 Charging Forward Capital Expenditures) in this
 17 program for the participating site hosts. Additionally, as the EV market matures
 18 and the costs associated with EV infrastructure are becoming more socialized (i.e.,
 19 distributed across a larger number of users), the need for such a waiver is
 20 diminishing. This market maturity reduces the need for regulatory mechanisms like
 21 the CIAC waiver, which were initially designed to stimulate interest and growth in
 22 EV adoption.

⁶ Actual total customer-owed CIAC spend for years 2019 through 2023, was \$275,000 in relation to Exhibit A-49 Schedule NN2 Charging Forward Capital total customers as reported with response to AGDE-4.140 question.

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1 Furthermore, as EV adoption increases, the costs associated with EV infrastructure
2 are being spread across a larger user base, further reducing the per-user cost.
3 Therefore, the CIAC waiver is no longer appropriate or necessary in the context of
4 a maturing and cost-socialized EV market. Lastly, as noted with my testimony on
5 page 51, rows 9 through 12, the decision to no longer waive CIAC is in alignment
6 with feedback received from key stakeholders and making the rate book
7 modification will align the rate book and the TEP.

8

9 **Topic 13: Rebuttal to Benefit Cost Analysis for TEP**

10 **Q38. What is your reply to MEIU Witness Sherman's three concerns about the TEP**
11 **BCA (pages 20 line 8 through page 25 line 8)?**

12 A38. Witness Sherman mentions three concerns about the TEP BCA – First, she asserts
13 that the Company's BCA is overly conservative in a number of its assumptions.
14 Second, Witness Sherman concludes that the Company's BCA incorrectly assumes
15 a constant utilization rate over time for all types of chargers. Finally, Witness
16 Sherman responds that the Company's BCA fails to account for any of the societal
17 benefits realized as a result of transportation electrification.

18

19 First, accounting for all of the increase in expected revenue from increased EV
20 charging in the TEP instead of 10% of the expected revenue is a conservative
21 approach intentionally adopted by the Company. It is important to strive for
22 accuracy in estimating the benefits of EV charging and by accounting for only 10%
23 of the benefits, the BCA is approaching risk mitigation conservatively ensuring that
24 even if the actual benefits are lower than expected, the investment will still be
25 justified. Additionally, the BCA focuses on the incremental load from rebated
26 chargers, which is a more accurate reflection of the direct impact of the Company's

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1 program. While network effects and indirect impacts are important, they can be
2 difficult to measure and attribute directly to the DTE Electric program.

3

4 Second, for Witness Sherman's concern about including an increasing utilization
5 rate over time for public chargers, the Company believes it is crucial to take a
6 balanced and sustainable approach to expanding public charging infrastructure.
7 This involves taking into consideration technological advancements such as faster
8 charging times that reduce the need for a high number of public charging stations,
9 and user behavior such as EV owners' preference to charge their vehicles at home
10 overnight.

11

12 Third, the Company deems that adding additional societal benefits such as
13 greenhouse gas and criteria pollutant emission reductions to the BCA may not be
14 appropriate due to many reasons, including attribution, uncertainty, and equity. It
15 is crucial to strike a balance between comprehensive analysis and focused
16 actionable insights for the Company's operations and investments. The primary
17 purpose of the Company's BCA is to assess the costs and benefits directly
18 associated with its operations and investments, and these benefits are often indirect
19 and realized by society at large. While some additional benefits may be quantified,
20 such as using the Federal Social Cost of Carbon (SCC) to calculate the benefits of
21 carbon reductions, attributing these benefits to the actions of a single company can
22 be challenging. Additionally, future regulatory changes, technological
23 advancements, and shifts in societal behavior can significantly impact the
24 realization and magnitude of these benefits. Lastly, the additional benefits of

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1 transportation electrification (like improved air quality) might not be evenly
2 distributed and may disproportionately benefit certain groups over others.

3

4 Based on these considerations, the Commission should reject the changes Witness
5 Sherman proposes regarding modifying the Company's BCA analysis.

6

7 **Q39. How do you respond to Staff Witness Revere's (page 8 lines 1-20) concerns**
8 **regarding site-specific BCAs for fleet customers, and only allowing rebates for**
9 **net positive BCAs for other customers?**

10 A39. The Company does not agree with Staff Witness Revere. It is important to consider
11 the portfolio-level benefits that extend beyond the individual customer or fleet
12 segment. Conducting individual BCAs for each fleet customer can be
13 administratively burdensome and costly. These administrative costs, which will
14 ultimately be borne by customers, could potentially offset some of the benefits
15 derived from individual positive BCAs.

16

17 **Q40. How do you respond to MNSC Witness Jester's recommendation on page 40**
18 **line 4 through page 42 line 7 to the Commission to generally support DTE**
19 **Electric's proposed spending, without endorsing the benefit-cost analysis as**
20 **presented?**

21 A40. The Company does not agree with MNSC Witness Jester's critique of the benefit-
22 cost analysis presented by the Company and is disappointed in his unwillingness to
23 endorse it. However, the BCA as presented by DTE Electric provides an
24 appropriately comprehensive, conservative, and realistic assessment of the costs
25 and benefits of its TEP. Therefore, the Company's BCA appropriately supports the

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1 proposed levels of Company TEP spending. Witness Jester favors a BCA that far
2 exceeds the scope of this case and evaluates a wide variety of matters with, at best,
3 oblique connections to the Company's electric rates. The Company's attribution of
4 only a portion of EV adoption to DTE Electric's TEP is a conservative approach
5 that takes into account the fact that not all EV adoption can be directly attributed to
6 the Company's efforts. This approach avoids overestimating the benefits of the
7 TEP, thereby providing a more realistic assessment of its impact. Witness Jester's
8 comparison to line extensions is not entirely appropriate. Line extensions are a
9 direct result of utility investment, whereas EV adoption is influenced by a multitude
10 of factors beyond the Company's control, such as vehicle availability, government
11 incentives, and individual consumer preferences. The BCA also takes into account
12 the impacts on non-participating customers by attributing only a conservative
13 portion of EV adoption to the TEP and ensuring that the costs borne by non-
14 participating customers are not overstated. Therefore, it is reasonable for DTE
15 Electric to attribute only a portion of EV adoption to its TEP.

16

17 **Topic 14: Credit and Debit Card Merchant Fees**

18 **Q41. Did Attorney General Witness Coppola agree that DTE Electric should**
19 **continue to recover non-residential merchant fees?**

20 A41. No, Witness Coppola proposes disallowance of \$3.5 million of non-residential
21 merchant fees by the Company. Witness Coppola argues, on page 107, lines 13-16,
22 "Non-residential customers, which consists primarily of small to medium size
23 commercial and industrial businesses, have more options and sophistication than
24 residential customers to pay their gas and electric bills through other less costly
25 means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House

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1 (ACH).” On page 108, lines 3-8, Witness Coppola also argues that the Company
2 should follow Consumers Energy’s actions and reimpose a convenience fee for
3 customers. DTE Electric does not agree that non-residential customers should be
4 charged a convenience fee to utilize a credit / debit card to pay their utility bill.
5 Business customers appreciate the flexibility and convenience to choose a card
6 payment transaction.

7

8 **Q42. Has DTE Electric implemented mitigation policies to decrease non-residential**
9 **merchant fees?**

10 A42. Yes. In 2019, the Company began mitigating merchant fees with a rate blocking
11 policy for large commercial and industrial customers. The Company further
12 limited usage of credit cards for customers with over \$75,000 in annual usage
13 beginning in 2021.

14

15 **Q43. Which DTE Electric non-residential customers are utilizing credit/debit cards**
16 **to pay their utility bill?**

17 A43. Given the two mitigation policies implemented, we believe the 54,000 non-
18 residential customers that utilized a card payment last year are largely small
19 business customers that often utilize credit cards to run their businesses and who
20 may not use other tools such as EFT. Furthermore, according to the National Small
21 Business Association, approximately 37% of small businesses have used credit
22 cards over the past 12 months to meet their capital needs which suggests that
23 facilitating credit card use for small business is a meaningful part of maintaining
24 business customer satisfaction and financial flexibility.

Line
No.

1 **Q44. Does this conclude your rebuttal testimony?**

2 A44. Yes, it does.

1 JUDGE WALLACE: O.K. Next,
2 Mr. Christinidis.

3 MR. CHRISTINIDIS: Briefly, your Honor, I
4 believe there's one additional exhibit and Schedule
5 associated with Ms. Uzenski that I may have missed; if
6 you give me one second, I can try to clarify that.
7 Ms. Uzenski also cosponsors Exhibit A-27 Q1 with Witness
8 Foley, so we would move the admission of that exhibit as
9 well to the extent that's necessary here this morning.

10 JUDGE WALLACE: All right. Thank you,
11 Mr. Christinidis, for clarifying that. O.K. Back to
12 you, then.

13 MR. CHRISTINIDIS: Yes. Thank you, your
14 Honor. With that, I believe that covers the witnesses I
15 was going to sponsor today. Mr. Janiszewski will be up
16 next with a series of additional Company witnesses to
17 bind in.

18 JUDGE WALLACE: Thank you. Please go
19 ahead, Mr. Janiszewski.

20 MR. JANISZEWSKI: Thank you, your Honor.
21 At this time, the Company moves to bind into the record
22 the Qualifications and Revised Direct Testimony of Pankaj
23 Sharma, consisting of a cover sheet and 141 pages of
24 questions and answers. The Company also moves for the
25 admission of the following 13 direct exhibits that

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

1 accompanied Mr. Sharma's revised direct testimony marked
2 as Exhibit A-12 Schedule B5.7, Exhibit A-12 Schedule
3 B5.7.1, Exhibit A-12 Schedule B5.7.2, Exhibit A-12
4 Schedule B5.7.4, Exhibit A-12 Schedule B5.7.5, Exhibit
5 A-12 Schedule B5.7.6, Exhibit A-12 Schedule B5.7.7,
6 Exhibit A-12 Schedule B5.7.8, Exhibit A-12 Schedule
7 B5.7.9, Exhibit A-13 Schedule C5.13, Exhibit A-24
8 Schedule N1, Exhibit A-24 Schedule N2, and Exhibit A-24
9 Schedule N3. Next, the Company moves to bind into the
10 record the Rebuttal Testimony of Pankaj Sharma,
11 consisting of a cover sheet and 19 pages of questions and
12 answers. The Company also moves for the admission of the
13 four rebuttal exhibits that accompanied Mr. Sharma's
14 rebuttal testimony, marked as Exhibit A-46 Schedule KK1,
15 Exhibit A-46 Schedule KK2, Exhibit A-46 Schedule KK3, and
16 Exhibit A-46 Schedule KK4. And there are no changes to
17 Mr. Sharma's revised direct testimony, rebuttal
18 testimony, or any of his exhibits.

19 JUDGE WALLACE: O.K. Is there any
20 objection to binding in revised direct testimony of
21 Mr. Sharma?

22 Hearing none, the testimony is bound in.

23 Is there any objection to binding in the
24 rebuttal testimony of Mr. Sharma?

25 Hearing none, the testimony is bound in.

1 Is there any objection to any of the
2 exhibits or associated schedules that were sponsored by
3 Mr. Sharma for admission once we've completed binding in
4 the remaining Company testimony? (No response.)

5 (Testimony bound in.)

6 - - -

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
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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

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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

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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.

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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

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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

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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%					

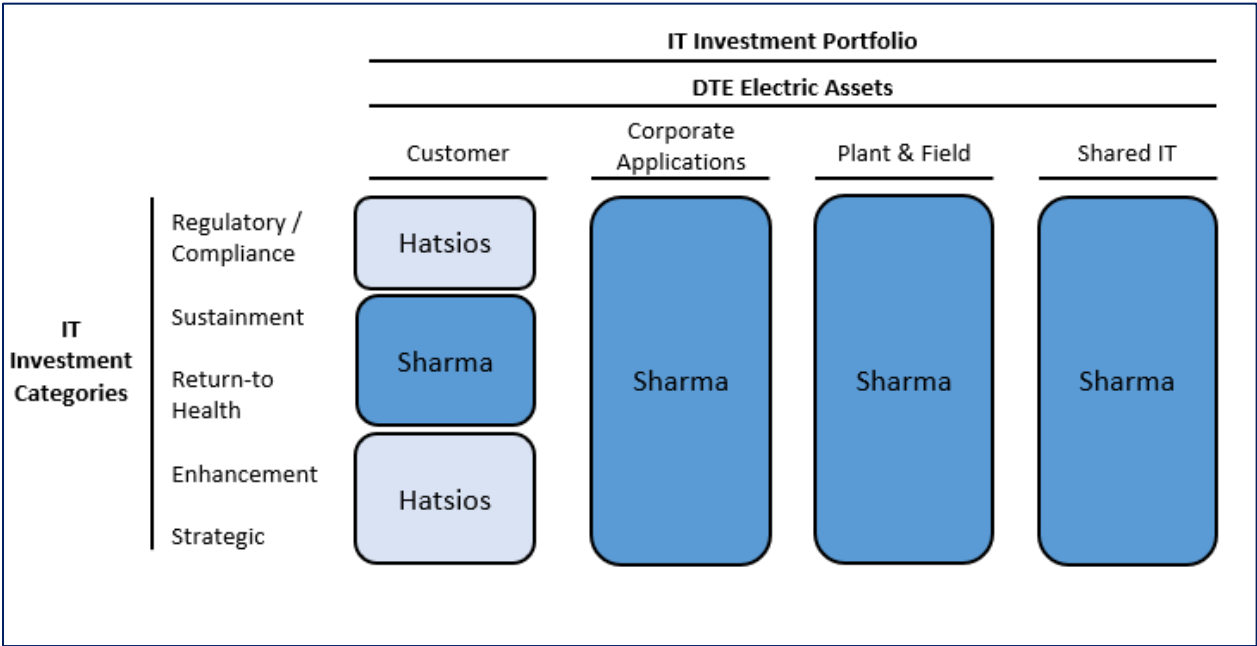
Q19. What is the portfolio structure within the DTE IT organization, and how is it reflected in your testimony?

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.

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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.

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- 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

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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

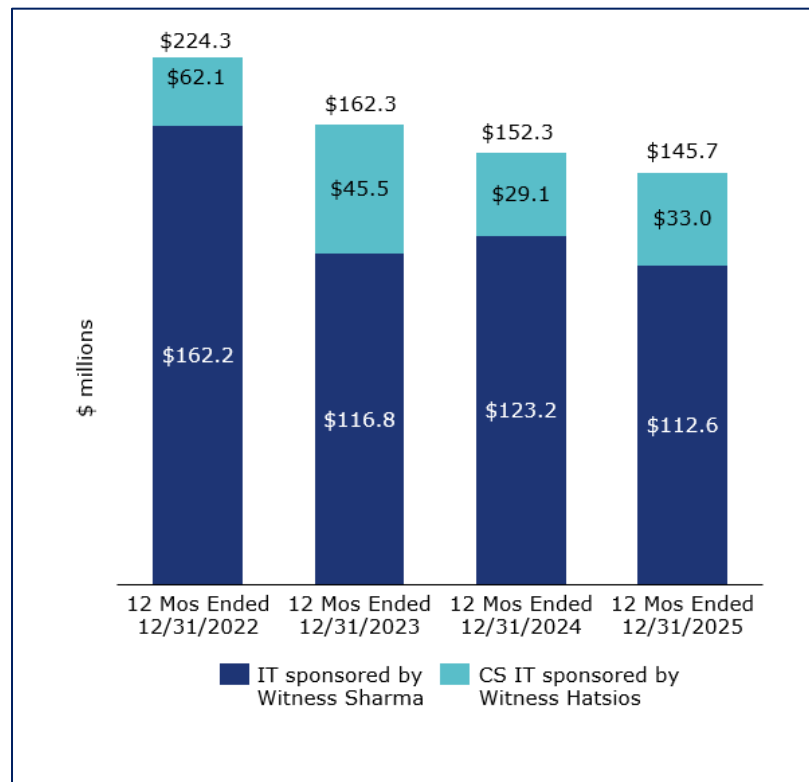
3

Using this nomenclature, I can summarize DTE IT capital both by year and by

4

category as seen in Figures 6 and 7 below.

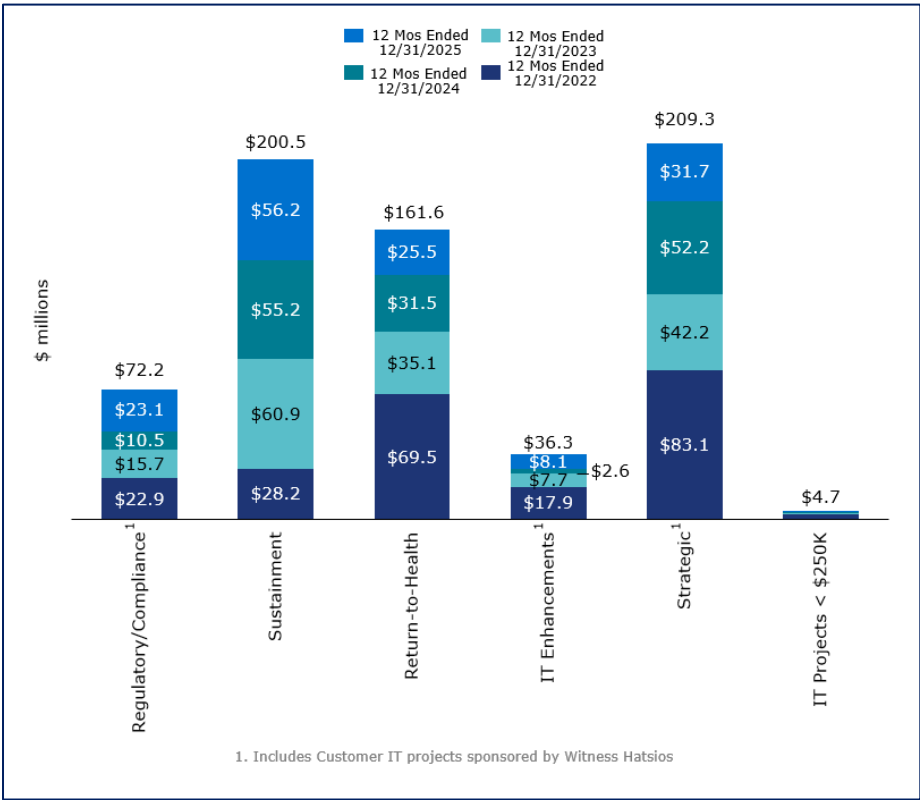
5

Figure 6 DTE Electric IT Capital Expenditure by Period

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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?**

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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.

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- 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
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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

Corporate Applications

2

Q27. Can you describe the Corporate Applications portfolio?

3

A27. The Corporate Applications portfolio encompasses assets used by the enterprise to execute critical internal business functions. It supports business units such as Human Resources, Finance and Controller, Legal, Supply Chain, Fleet & Facilities, and IT assets used by the entire enterprise. In addition, Corporate Applications portfolio provides Enterprise Automation solutions for the enterprise. The investments within Corporate Applications span the 5 investment categories outlined/described above and the specific projects are detailed in the section below.

11

Q28. What are the projected costs for investments in the Corporate Applications Portfolio?

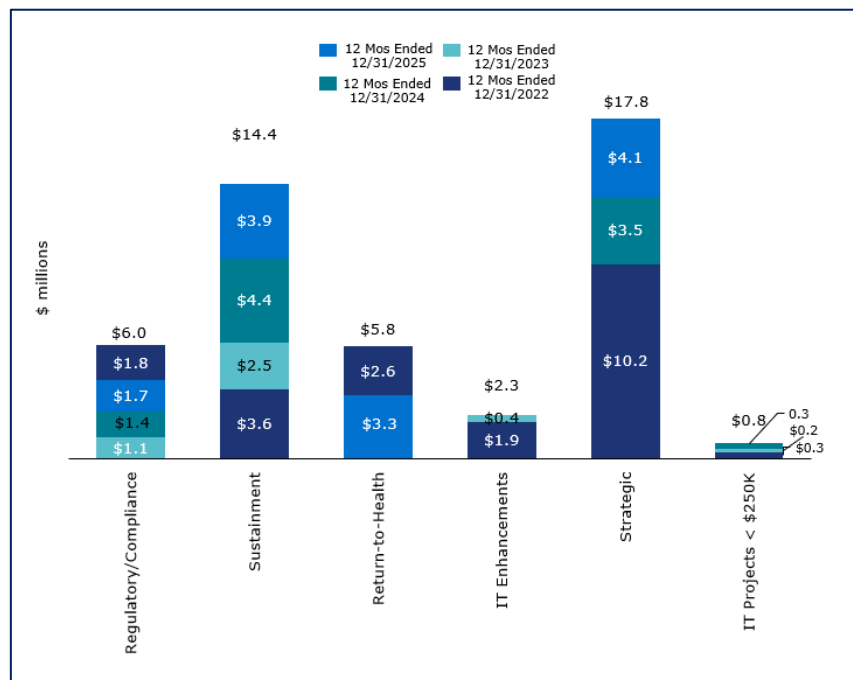
13

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?**

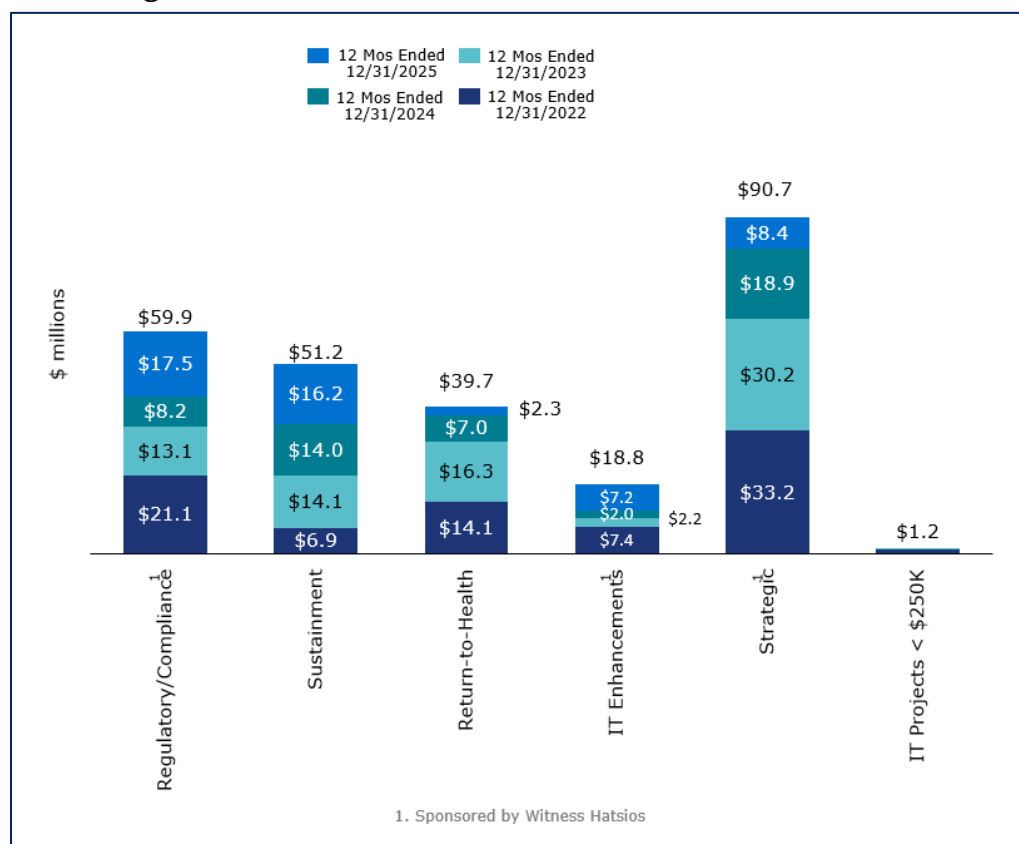
19 A35. As reflected on line 3 of Exhibit A-12 Schedule B5.7, page 1, capital costs for the
20 Sustainment and Return to Health category investments in Customer Service
21 Portfolio total \$21.6 million for the historical test year ending December 31, 2022,
22 \$51.5 million in the bridge period (for 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
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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.

1 **Closed Loop COCL Application Health**

- 2 • The Company will invest \$1.6 million in the **Closed Loop COCL Application**
3 **Health** project over the course of 36-months ending December 31, 2025, as shown
4 on line 4 of Exhibit A-12 Schedule B5.7.2.

5 This project will utilize agile delivery to roll out incremental improvements for
6 customer transactions on the web such as billing, usage, payments, outage, program
7 enrollment, Collections Closed Loop, and MIMO (Move-In/Move-Out) Closed
8 Loop process improvements. In support of the Digital Experience Team, the project
9 team will provide Azure APIM (API Management) including Network
10 configuration, Firewall configuration, access management and managing the API
11 gateway in support of web services, and awareness in system health insight.
12 Additional Dynatrace licenses will be utilized for integrating Azure with Dynatrace
13 and will provide the ability to monitor the customer experience and make necessary
14 adjustments.

15 The Company reflects a variance of \$0.4 million less in the 36 months ending
16 December 31, 2024, than was approved for cost recovery in U-21297. This is
17 primarily due to cost savings initiatives associated with service providers
18 supporting the projects.

19 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
20 24 N3 Line 63 for additional project details.

21

22 **Cloud Platform Enterprise Agreement**

- 23 • The Company will invest \$0.8 million in the **Cloud Platform Enterprise**
24 **Agreement** project over the course of 12-months ending December 31, 2024, as
25 shown on line 5 of Exhibit A-12 Schedule B5.7.2.

Line
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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.

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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

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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
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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
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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

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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.

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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

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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

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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
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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
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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

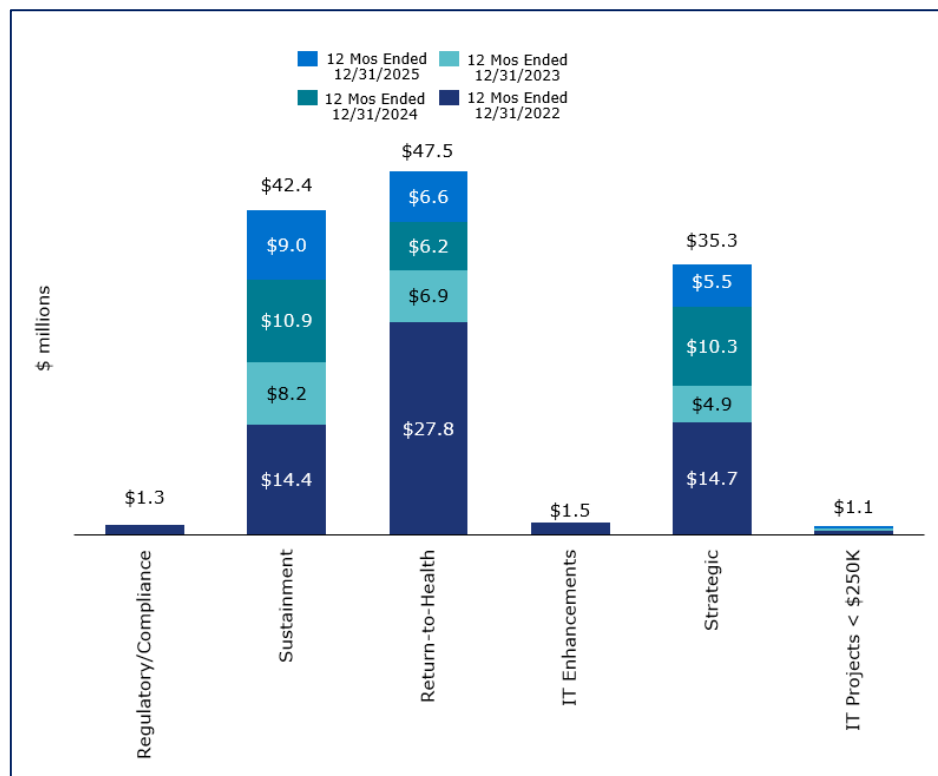
23 **Q39. What are the projected costs for investments in the Plant & Field Portfolio?**

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
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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
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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

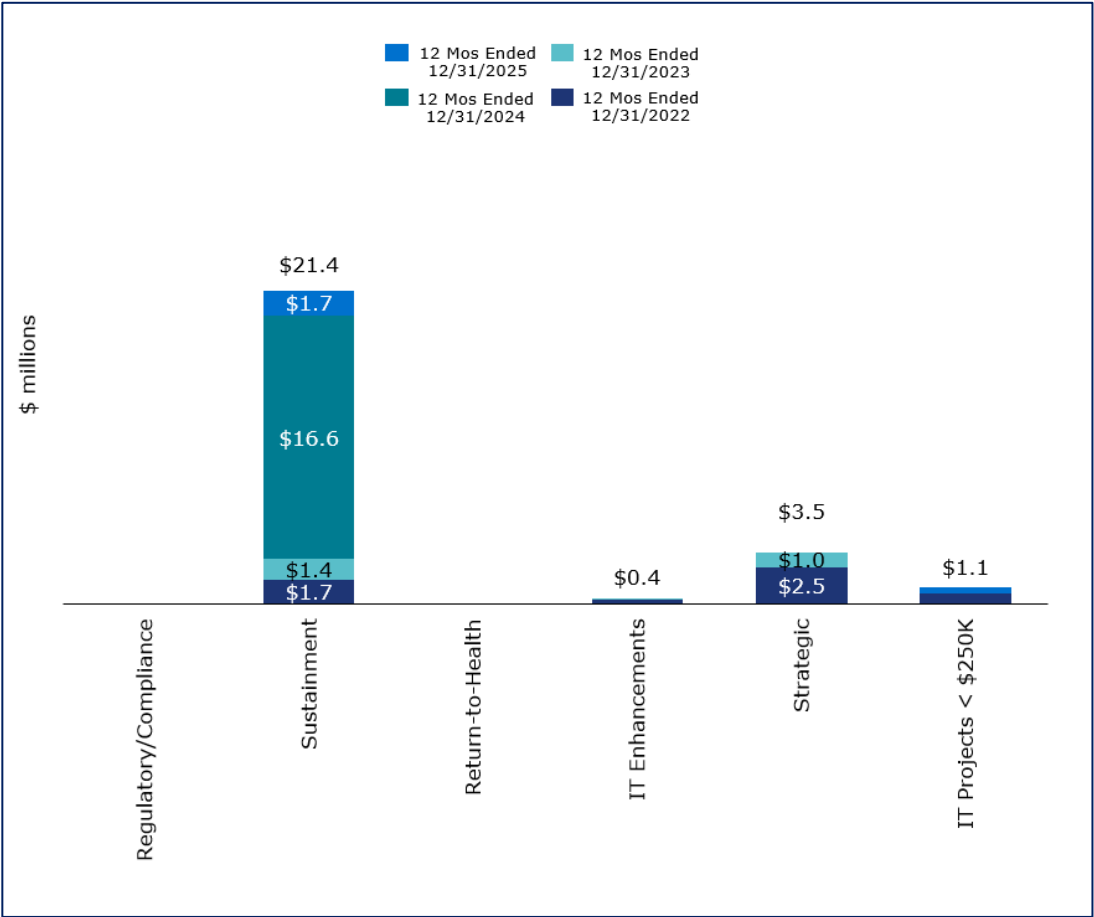
23 **Q46. What are the projected costs for investments in the IT for IT Portfolio?**

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

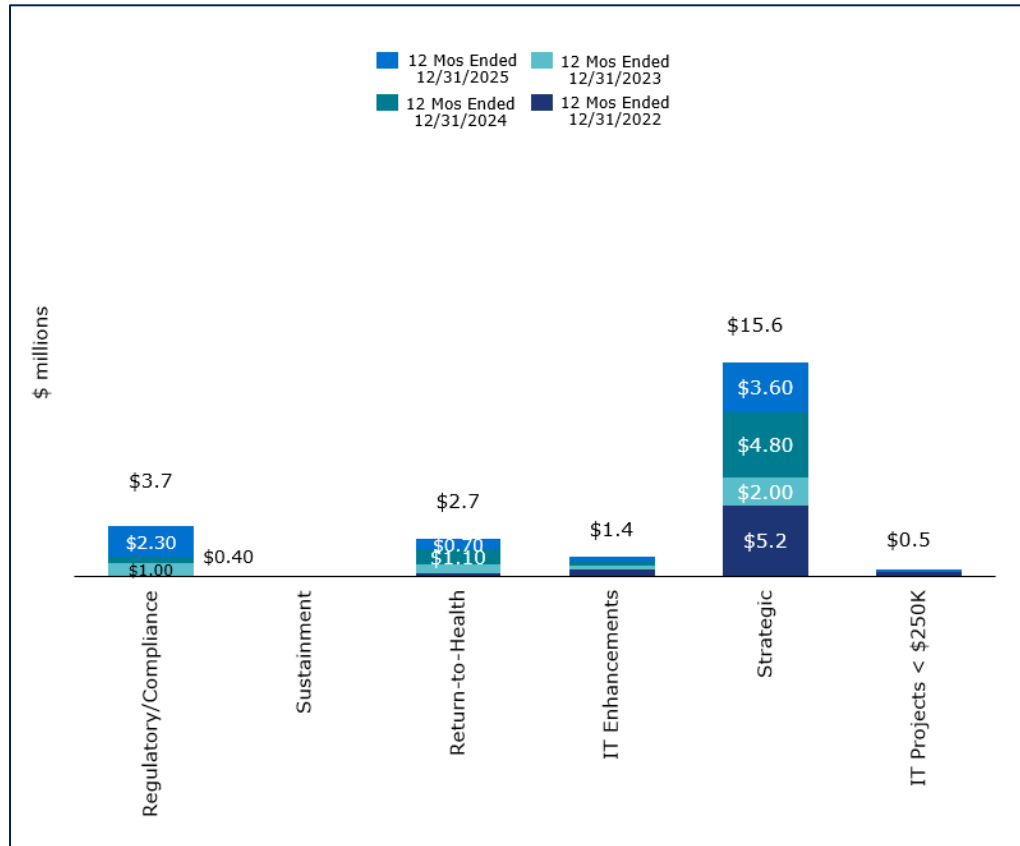
9 **Q50. What are the projected costs for investments in the IPS Portfolio?**

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
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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-Health

11 **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
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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
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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

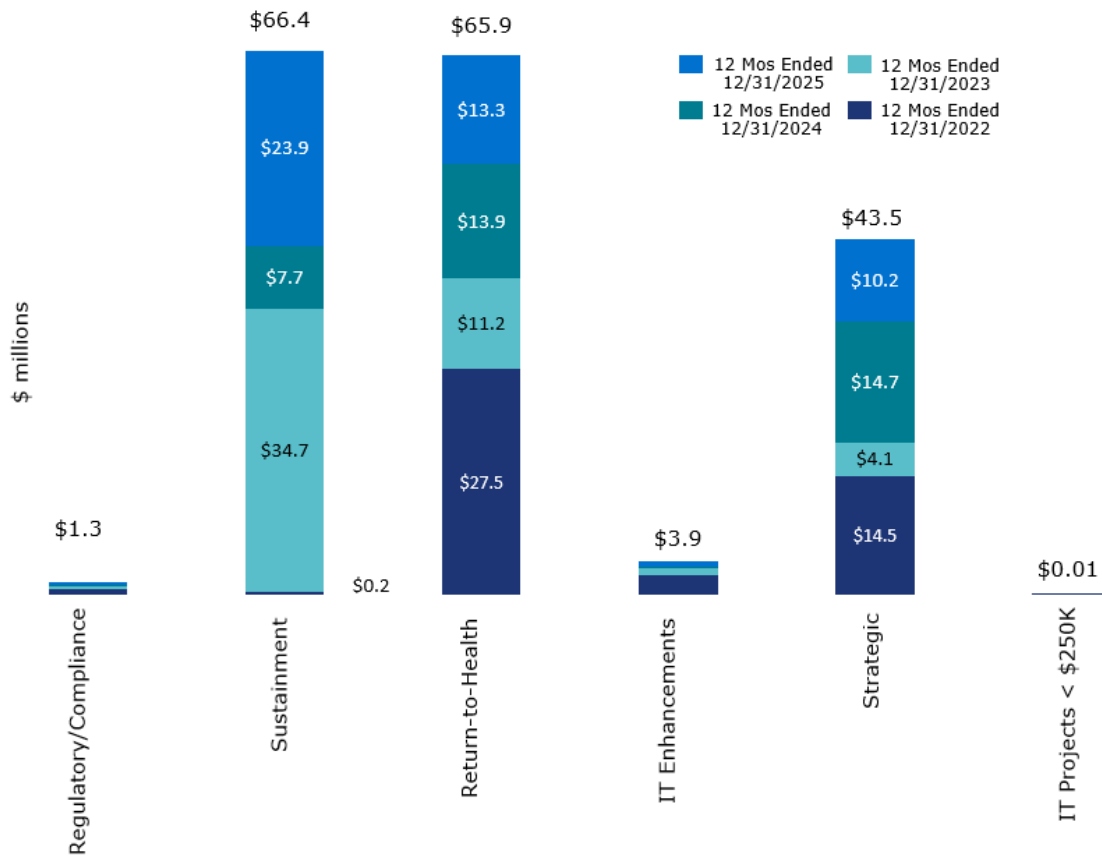
19 **Q56. What are the projected costs for investments in the Infrastructure Operations**
20 **Portfolio?**

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.

1 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
2 B5.7.7. The synopses below generally provide the total spend for each line item the
3 Company requests in this rate case and the details regarding breakout by historical
4 period, projected bridge period, and projected test period, are each laid out in
5 Exhibit A-12 Schedule B5.7.7, in columns d, g and h, respectively. Figure 12
6 represents a high-level view of capital allocation within the portfolio.

8 **Figure 13 Infrastructure Operations – IT Investment**



9

10 Regulatory/Compliance

11 **Q57. Can you explain in detail the Infrastructure Operations investment in the**
12 **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.

3 **Endpoint Devices Replaced by Year**

4

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.

6

7 **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).

20 **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.

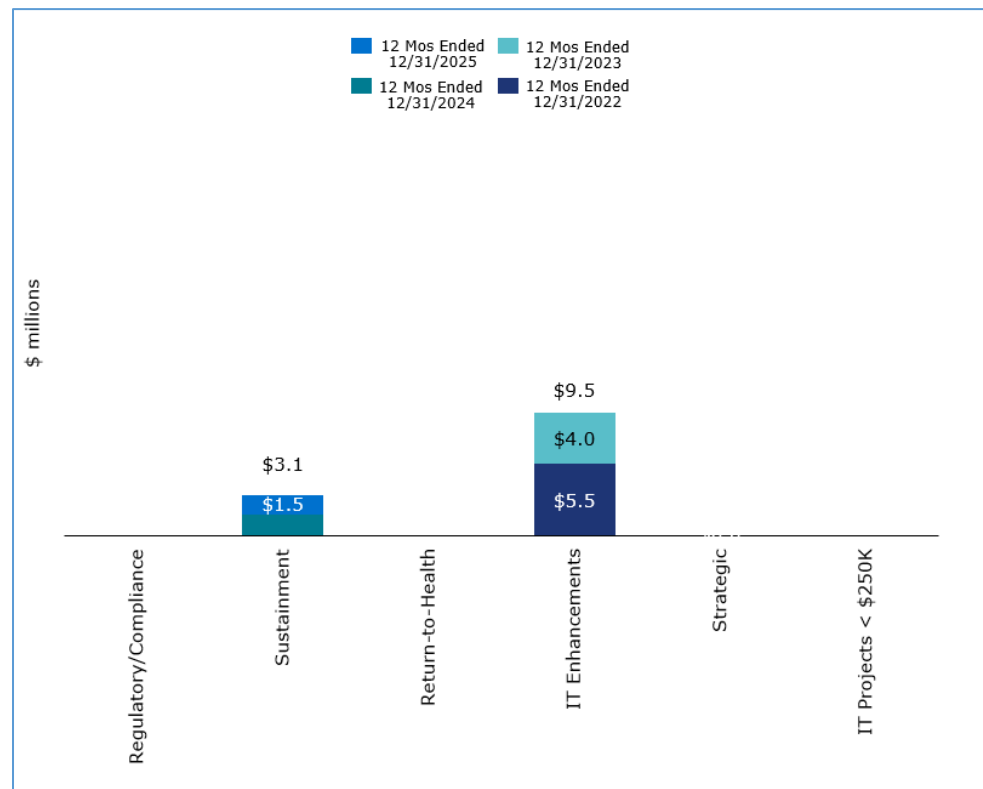
Line
No.

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 COPS 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
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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.

14 **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' testimony 2022 Historical Project Spend Variance.

3

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 nor are planned to be completed in 2024 as previously approved and included in rates in Case No. U-21297.

9

10

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
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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

REBUTTAL TESTIMONY

OF

PANKAJ SHARMA

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF PANKAJ SHARMA

Line
No.

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

3 A1. My name is Pankaj Sharma (he/him/his). My business address is One Energy Plaza
4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC
5 (LLC), as Director – Information Officer within the Information Technology
6 Services (ITS) organization.

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. The purpose of my rebuttal testimony is to address the disallowances proposed by
15 Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
16 Witness Rogers and Attorney General (AG) Witness Coppola, as listed below.

17 • Refute Staff Witness Rogers’ proposed Capital disallowance of \$42.6 million
18 in 2024 and 2025 and the associated O&M of \$2.4 million for IT projects with
19 Level 2 cost estimates

20 • Refute Staff Witness Rogers’ proposed capital disallowance of \$11.32 million
21 in 2023, \$0.55 million in 2024 and \$0.82 million in the 2025 and the
22 associated O&M of \$0.08 million for IT projects with Level 3 cost estimates

23

Line
No.

- 1 • Refute Staff Witness Rogers’ proposed Capital disallowances of the
- 2 individual IT projects listed below totaling \$3.44 million
- 3 ○ Digital Worker Experience EOL
- 4 ○ End of Life Asset Replacements
- 5 • Refute Attorney General (AG) Witness Coppola’s proposed Capital
- 6 disallowances of the individual IT project listed below \$4.17 million:
- 7 ○ Enhanced Document Management Capabilities
- 8 • Refute AG Witness Coppola’s proposed disallowance of \$34.85 million for
- 9 2023 Capital expenditure that the Company underspent

10

11 I am refuting certain positions taken by Michigan Energy Innovation Business
12 Council, the Institute for Energy Innovation, and Advanced Energy United
13 (collectively MEIU) Witness Barnes regarding the Company’s IT Annual
14 Planning Cycle (APC) and prioritization process.

15

16 The absence of a discussion of other matters in my rebuttal testimony should not
17 be taken as an indication that I agree with other aspects of any Staff or Intervenor
18 testimony.

19

20 **Q4. Are you sponsoring any exhibits as part of your rebuttal testimony?**

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

22	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
23	A-46	KK1	Estimate comparison Level 2 to Level 3
24			for 2024 Spend Year
25	A-46	KK2	Schedule B5.7.1 2024-2025 Projects (\$3M or

Line
No.

1 greater)
2 A-46 KK3 Complete AGDE-3.122 2023 IT Capital Costs
3 A-46 KK4 Over Recovery Analysis - Level 3
4

5 **Q5. Were these exhibits prepared by you or under your direction?**

6 A5. Yes, they were.

7

8 **IT Projects with a Level 2 Cost Estimate:**

9 **Q6. What disallowances did Staff propose related to IT Capital projects with a**
10 **Level 2 cost estimate?**

11 A6. On page 6, lines 6-9 of Staff Witness Rogers Direct Testimony, Staff has proposed
12 a 20% adjustment resulting in total Level 2 Capital disallowances of \$42.60 million
13 (2024 \$22.43 million + 2025 \$20.17 million) as well as an O&M disallowance of
14 \$2.39 million of investments presented in my direct testimony.

15

16 **Q7. What reasons does Staff Witness Rogers provide for these proposed**
17 **disallowances?**

18 A7. On page 6 lines 14-20 and page 7 line 1, Staff Witness Rogers states:

19 “IT projects are given a Level 2 cost estimate more than a year before they are
20 ready for implementation. Additional reviews, final approval, and budget
21 allocation occur after projects are given a Level 2 cost estimate. Many things
22 can happen between the time a project is given a Level 2 cost estimate and the
23 year or more later at the time of execution including a change in scope, a change
24 in schedule, the quote from the vendor, prioritization within the APC, or the
25 necessity of the project altogether.”

Line
No.

1 Staff Witness Rogers' direct testimony on page 7, also compared IT projects with
2 Level 2 estimates in Case No. U-21297 (previous rate case) with Level 3 estimates
3 in Case No. U-21534 (this instant case). She then calculated the percentage
4 difference of the Level 2 and Level 3 project costs (to range from -99.86% to
5 277.36%) to determine if the Company had over recovered or under-recovered) as
6 a reason for disallowance. See Witness Rogers' direct testimony page 7 lines 7-16
7 and Exhibit S-15.4. Additionally, she compares DTE Electric's Level 2 estimates
8 to the American Association of Cost Engineering (AACE) Class 3 estimates and is
9 using the lower bound of -20% as the criteria for the recommended disallowance¹.

10

11 **Q8. Do you agree with Staff Witness Rogers' 20% variance recommendation when**
12 **comparing DTE Electric's IT Level 2 estimate classification to AACE Class 3**
13 **estimate?**

14 A8. No, I do not agree. Staff Witness Rogers' selection and recommendation of the
15 lowest accuracy range provided for Class 3 estimates fails to consider that the
16 AACE Class 3 estimates also provide an upper range for Class 3 estimates at
17 +30%². As to the AACE Class 3 estimate criteria, while the Company does not
18 agree that the Commission should apply a wholesale percentage and use an upper
19 range for disallowance, it is more accurate to compare Level 2 estimates to AACE
20 Class 2 estimates. This is consistent with the level of project definition deliverables
21 defined, and reviews completed, as part of the Company's APC process and as
22 defined in Figure 1 below.

23

¹ Rogers DT, page 8, lines 7-19

² https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4, page 3, Table 1

Line
No.

1

Figure 1 AACE Cost Estimate Classes

ESTIMATE CLASS	Primary Characteristic	Secondary Characteristic			
	LEVEL OF PROJECT DEFINITION Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE Typical variation in low and high ranges [a]	PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes:

[a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

2

3 **Q9. Should the Commission accept Staff Witness Rogers' recommendation for a**
4 **20% reduction of Level 2 cost estimate IT projects and the proposed**
5 **disallowance?**

6 A9. No, the Commission should reject the proposed Capital disallowance by Staff
7 Witness Rogers of \$42.6 million for 2024 (\$22.4 million) and 2025 (\$20.4 million)
8 and associated O&M of \$2.4 million. The Company's commitment to improving
9 estimates is evident when compared to the cost estimate data in its entirety. These
10 disallowances are each addressed below.

11

Line
No.

1 **\$22.4 million Capital Disallowance for 2024 Spend year:**

2 At the time of the Case No. U-21534 rate case filing, 87 projects were submitted
3 with a Level 2 estimate. Since then, all of these projects have undergone additional
4 review cycles and progressed to the project planning and execution phase. The
5 estimates for these projects have progressed to Level 3. Upon further analysis, 46
6 projects show a 0% variance and 32 projects are within the variance allowance of
7 a Level 3 estimate (AACE class 1). This analysis is a comparison of the Level 3
8 estimates to the Level 2 estimates in this instant case. The variance analysis in
9 project estimates demonstrates that the Company is on track to meet its planned
10 capital expenditures in 2024.

11 Table 1 below shows a high-level breakdown of the 78 identified projects. Detailed
12 information is provided in Exhibit A-46 Schedule KK1.

13 **Table 1 Level 2 to Level 3 Estimate Difference**

Level 2 to Level 3 Estimate Difference	No. of Projects	Staff proposed 20% Capital disallowance (\$ millions)
0% Variance	46	\$15.3
Greater than 0% - less than 10% Variance	32	\$5.6

14

15 As shown above these 78 project estimates should be considered Level 3 and
16 therefore, at a minimum, \$20.9 million out of the \$22.4 million of Staff's
17 recommended Capital disallowance should be rejected.

18 **\$20.2 million Capital Disallowance and \$2.4 million O&M for 2025 Spend**
19 **year:**

Line
No.

1 I do not agree with Staff's recommended Capital Disallowance of \$20.2 million
2 and O&M disallowance of \$2.4 million in 2025 for several reasons. First, Staff
3 Witness Rogers claims that the Level 2 cost estimates are obtained prior to a
4 comprehensive review. As represented in my Revised Direct Testimony in Figure
5 1 on page 7, projects in the N+2-year planning cycle are in the base plan, which I
6 have secured approval of in the financial base plan from the Technology Investment
7 Committee. Additionally, Level 2 cost estimates are comprehensive by cost type
8 and phase (where applicable to the project) and have been supported by the IT
9 architecture team. IT business case costs are estimated as part of a rigorous APC
10 process where detailed estimates (Level 2) are developed, which include labor,
11 software, hardware, and vendor/consulting costs. The estimates are developed
12 through input and reviews from eight discreet IT subject matter experts (SME)
13 teams based on Scope, Technology, historical data. and vendor quotes. All
14 estimates are then reviewed and validated against Company policies, including the
15 capitalization policy. At project execution, the Level 2 estimates are further vetted
16 and refined before transitioning into a Level 3 estimate. Therefore, given the
17 comprehensive and diligent reviews conducted for development of the Level 2
18 estimates which are in alignment with the AACE Class 2 estimates, the 20% blanket
19 disallowance of \$20.2 million Capital disallowance and \$2.4 million O&M for
20 2025 should be rejected.

21

22 **IT Projects with a Level 3 Cost Estimate:**

23 **Q10. What disallowances did Staff propose related to IT capital projects with a**
24 **Level 3 cost estimate (page 10, lines 18-19 and page 11, lines 1-2)?**

Line
No.

1 A10. Staff Witness Rogers recommends a 10% disallowance to IT projects with a Level
2 3 cost estimate resulting in total capital disallowances of \$12.68 million as well as
3 an O&M disallowance of \$0.08 million.

4

5 **Q11. What reasons does Staff Witness Rogers provide for these proposed**
6 **disallowances?**

7 A11. On page 11, lines 3-8 of Staff Witness Rogers' direct testimony states:
8 Staff recommends a 10% disallowance to IT projects with a Level 3 cost
9 estimate due to their inaccurate nature. Using a spreadsheet of IT projects with
10 Level 3 cost estimates provided through audit in Case No. U-21297, Staff
11 compared the then Level 3 cost estimate with the actual cost in the instant case.

12

13 **Q12. Do you agree with Staff Witness Rogers' -10% variance recommendation**
14 **when comparing DTE Electric's U-21297 Level 3 cost estimates with U-21534**
15 **Actuals?**

16 A12. No, I do not agree. Staff compared the Level 3 cost estimates in Case No. U-21297
17 for 2022 and the actual cost in the instant case for 2022 for the basis of 10% blanket
18 disallowance of all Level 3 estimates. As per the analysis provided by Staff in
19 Exhibit S-15.6 titled "Comparison of Level 3 Cost and Actual Costs," annual costs
20 for projects were used to determine variance. However, this provides only a partial
21 view of total project costs and should not be the determining factor for a blanket
22 10% disallowance for all Level 3 projects. For determination of over recovery or
23 under recovery, the total costs approved for cost recovery in Case No. U-21297
24 should be compared to costs submitted as part of the instant rate case within the 36
25 months ending December 31, 2024.

Line
No.

1 As reflected in Exhibit A-46, Schedule KK4, titled "Over Recovery Analysis -
2 Level 3," the Company conducted an analysis for all 70 projects identified as over
3 recovered projects, comparing the total costs approved for recovery in Case No. U-
4 21297 to the costs submitted as part of the instant rate case within the 36 months
5 ending December 31, 2024. Out of the 70 projects identified as over recovered
6 projects in Exhibit S-15.6, 49 projects were identified to be within the variance
7 specification allowance, as these may contain Actuals and Level 1, Level 2 and
8 Level 3 estimates. Therefore, these 49 projects should not be considered as part of
9 the over recovery.

10

11 Additionally, Witness Sharma's Revised Direct Testimony in this case included
12 detailed commentary explaining why variances greater than 20% occurred for 13
13 projects. It is imperative to note that some of these variances were a result of
14 efficiency gained during project planning and execution, such as reduced vendor
15 costs via negotiations and optimized labor costs for technical work. The Company
16 is continuously looking for opportunities to achieve efficiency throughout the
17 project life cycle. Variances that resulted in efficiency gains should not be held
18 against the Company's estimation methodologies and be a reason for the 10%
19 blanket disallowance. Therefore, these 13 projects should also not be considered
20 for the 10% blanket disallowance. Lastly, the remaining 8 projects fall into the
21 category of under recovery due to partial or full disallowance from Case No. U-
22 21297. These projects had been initiated with anticipation for approval.

23

24 Also note Figure 2 below. A detailed analysis for all 70 projects has been provided
25 in Exhibit A-46, Schedule KK4, Over Recovery Analysis - Level 3.

Line
No.

1

Figure 2 Key projects showcasing the above reasoning

Staff Analysis comparing Annual costs									Company's Analysis comparing costs within 36 month period ending Dec 31, 2024					
Exh. A-24 N3 Line No.	Spend Year	Business Case Name	IT Portfolio	Total Projected IT Capital Cost (\$)	Cost Estimate Level	Actual Cost	Difference	Percent Difference	Overall project cost Approved U-21297	Overall project cost submitted for U-21534	Difference Between Approved U-21297 and Requested in U-21534	Overall Variance (Approved in U-21297 Vs. Requested U-21534)	Variance category	Reason Details
119	2022	API Integration Security Gateway and API Layer	Customer Service	\$ 1,550,000	Level 3	\$80,000	-\$1,470,000	-94.84%	\$ -	\$ 100.00	\$ 100.00	100%	Under recovery greater than 20%	Overall project disallowance in U-21297, but project was initiated
180	2022	Fuel Supply Application Health	Plant and Field	\$ 470,000	Level 3	\$387,000	-\$83,000	-17.66%	\$ 1,239.60	\$ 1,240.00	\$ 0.40	0%	No Variance - Overall project Spend same	N/A
279	2022	Threat Intel module	Information Technology for IT	\$ 600,000	Level 3	\$524,000	-\$76,000	-12.67%	\$ 1,040.93	\$ 567.00	\$ (473.93)	46%	Over Recovery greater than 20%	External resource labor savings in the Palo Alto XSOAR solution

2

3 **Q13. Should the Commission accept Staff Witness Rogers' recommendation for a**
4 **10% reduction of Level 3 cost estimate IT projects and the proposed**
5 **disallowance?**

6 A13. No, based on the analysis provided above and supplemented by Exhibit A-46 KK4,
7 the Commission should fully reject Witness Rogers's recommendation for a blanket
8 Level 3 Capital disallowance of \$11.32 million for 2023, \$0.55 million for 2024,
9 \$0.82 million for 2025 and the associated O&M of \$0.08 million in the test year.

10

Individual IT Project Disallowances:

12 **Q14. Are there any individual IT Capital projects recommended for disallowance**
13 **by the Staff?**

14 A14. Yes, Staff Witness Rogers recommended a total of \$3.44 million in Capital
15 disallowances for the following IT projects:

- 16 • Digital Worker Experience EOL
- 17 • End of Life Asset Replacement

18

Line
No.

1 Digital Worker Experience EOL

2 **Q15. Why does Staff Witness Rogers recommend a disallowance for the Digital**
3 **Worker Experience EOL?**

4 A15. On page 15, lines 6 -20 and page 16 lines 1-4 Staff Witness Rogers in her direct
5 testimony states:

6 Staff's recommended adjustment is due to the Company's lack of support for
7 the full requested expense. In testimony, DTE provided Table 2, Endpoint
8 Devices Replaced by Year. This table supports the total number of laptops,
9 desktops, monitors, and tablets replaced in 2023, 2024, and 2025. Through
10 audit, Staff requested the cost of each individual laptop, desktop, monitor, and
11 tablet. The Company responded with the following prices: laptop kits- \$1655,
12 desktops- \$1105, monitors- \$165, and tablets- \$795. Using the number of
13 devices replaced from Table 2 and adding 125 units (at the most expensive
14 cost) for new hires and replacements, Staff calculated the total cost of the
15 devices from the information provided and the difference from the requested
16 expense. The Company states that in 2023, devices were deployed to support
17 ADMS, primarily in vehicles, requiring additional docks, cabling harnesses,
18 and installation, at a cost of \$0.8 million. Removing that expense from the
19 \$1.743 million difference in 2023 calculates to an expense difference of \$0.943
20 million. Staff's Total Recommended Adjustment for each year is the amount
21 that is unaccounted for. The Company failed to provide evidence in support of
22 these remaining costs for the Digital Worker Experience EOL.
23

24 **Q16. Do you agree with Staff Witness Rogers' recommended disallowance for the**
25 **Digital Worker Experience EOL?**

26 A16. No, I do not agree with Staff Witness Rogers' recommendation. Witness Rogers
27 used information from my Revised Direct Testimony, Table 2 Endpoint Devices
28 Replaced by Year on page 112. She also used information provided in the audit
29 response DR-1 Question No. 31 which read as "Regarding the Digital Worker
30 Experience Electric EOL project (Exhibit A-24 Sch N3 line 304), please provide
31 the cost of each individual laptop, desktop, tablet, and monitor". The information
32 provided in the audit response included quantity of units and devices unit cost only,
33 Refer to Exhibit S-15.7. It did not include labor costs required for configuration,

Line
No.

1 deployment and testing of the devices. Staff recognized the \$0.8 million required
2 to support ADMS, however there is still a difference of \$0.94 million needed for
3 the labor associated with the devices. Also, the difference of \$0.94 million for 2023,
4 \$0.96 million for 2024 and \$1.04 million for 2025 are labor costs for the respective
5 years and must be included when calculating total project costs as shown in Table
6 2 below:

7 **Table 2 : Cost Breakdown for Digital Worker Experience EOL**

	Refresh Year		
	2023	2024	2025
Device - Laptop	617	800	700
\$1,655 (Cost per Unit)	\$1,021,135	\$1,324,000	\$1,158,500
Device - Desktop	1	100	185
\$1,105 (Cost per Unit)	\$1,105	\$110,500	\$204,425
Device - Monitor	180	100	100
\$165 (Cost per Unit)	\$29,700	\$16,500	\$16,500
Device - Tablet	25	40	28
\$795 (Cost per Unit)	\$19,875	\$31,800	\$22,260
New hires Devices	125	125	125
\$1,655 (Cost per Unit)	\$206,875	\$206,875	\$206,875
Total Device Costs	\$1,278,690	\$1,689,675	\$1,608,560
Additional labor cost (ADMS)	\$800,000	\$0	\$0
Labor Costs	\$943,310	\$960,325	\$1,041,440
Requested Expense	\$3,022,000	\$2,650,000	\$2,650,000
DIFFERENCE	\$0	\$0	\$0
TOTAL RECOMMENDED ADJUSTMENT	\$0	\$0	\$0

8
9 As shown above in Table 2, upon addition of the labor costs to the total requested
10 expense reflects the same total amount as provided in Exhibit A-24 Sch N3 line
11 304-306. Therefore, the recommended adjustment of \$2.95 million for Digital
12 Worker Experience EOL by Witness Rogers in Exhibit S-15.7 should be rejected.

Line
No.

1 End of Life Asset Replacement

2 **Q17. Why does Staff Witness Rogers recommend a disallowance for the End-of-Life**
3 **Asset Replacement?**

4 A17. On page 17, lines 1 -9 Staff Witness Rogers states:

5 ...the End of Life Asset Replacements project had a variance of \$6.5 million
6 more in the 36 months ending December 31, 2024, than was approved for cost
7 recovery in U-21297, and \$6.1 million of that variance was due to the purchase
8 of a 3 year license purchase of VMWare in 2022. Company testimony also
9 includes a 2025 Capital expenditure request for the renewal of the VMWare 3
10 year license as its own project at a cost of \$5.6 million. The Company does not
11 provide any explanation as to the difference in cost between 2022 and 2025
12 for the 3 year license purchases.

13 **Q18. Do you agree with Staff Witness Rogers' recommended disallowance of \$0.5**
14 **million for the End of Asset Replacement?**

15 A18. No, I do not agree. The cost to renew VMWare licensing in 2022 was \$6.1 million.
16 However, this cost is anticipated to be reduced by \$0.5 million as projected for 2025
17 for a forecasted total of \$5.6 million in 2025. The Company is engaged in vendor
18 negotiations with a focus on increasing efficiency and managing workload with
19 other available technologies to possibly reduce the license costs by \$0.5 million in
20 2025 and reducing our projected VMWare license renewal costs by 8%-10%.
21 Therefore, the Commission should reject the Capital \$0.5 million disallowance for
22 savings captured via negotiations for VMWare licensing renewal for 2025.

23

24 **Q19. Are there any individual IT Capital projects recommended for disallowance**
25 **by AG Witness Coppola?**

26 A19. Yes, AG Witness Coppola recommended a total of \$4.17 million in Capital
27 disallowances for the following IT project:

Line
No.

- 1 • Enhanced Document Management Capability

2

3 Enhanced Document Management Capability

4 **Q20. Why does AG Witness Coppola recommend a disallowance for the Enhanced**
5 **Document Management Capability?**

6 A20. On page 49 lines 3 -9, AG Witness Coppola states:

7 In Schedule B5.7.1, there are two projects with Capital expenditures in excess
8 of \$3.0 million. The first project is on line 9 for Cloud Health and Safety, with
9 Capital expenditures of \$2,518,000 in 2024 and \$582,000 in 2025. The second
10 project is on line 16 for Enhanced Document Management Capability Projects,
11 with Capital expenditures of \$1,218,000 in 2024 and \$2,958,000 in 2025.
12 Given the lack of information, it is not possible to determine what phase those
13 projects are currently in or whether they will be completed by the end of the
14 projected test year and be used and useful.

15

16 **Q21. Do you agree with AG Witness Coppola’s recommended disallowance for the**
17 **Enhanced Document Management?**

18 A21. No, I do not agree. AG Witness Coppola’s testimony on pages 48-49 incorrectly
19 claims that the Company dismissed the request to provide project phases with
20 related timelines and the current phase of the project for two projects, namely Cloud
21 Health and Safety and Enhanced Document Management Capability. There was a
22 misalignment in the AG’s discovery request AGDE-3 Question, No. 123, which
23 has been sponsored by AG Witness Coppola as Exhibit AG-14. The Company
24 responded to AGDE-3, Question No. 123 by providing information on Customer
25 Services IT projects, but the AGDE-3, Question No. 123 included an incorrect
26 reference between the schedule number “Schedule B5.7.1” and the referenced

Line
No.

1 projects "Customer Service IT". As reflected in Exhibit A-14, AGDE-3, Question
2 No. 123, read as follows:

3 **Refer to Exhibit A-12, Schedule B5.7.1 on Customer Services IT projects.**
4 For each project of \$3.0M or greater in 2024 and 2025, please:

5 a. Describe the project, what is being done, and why it is necessary to
6 undertake each project.

7 b. Provide the project phases of development with related timeline and the
8 identify the current phase of development (i.e., needs identification, initial
9 concept, system requirements, implementation, completed) and the target in-
10 service date.

11 c. Provide the project cost by year from inception to completion.

12 d. Provide a copy of the cost/benefit analysis showing each project was
13 economically justified.

14
15 In response to the misaligned AGDE-3, Question No. 123, the requested
16 information for Customer Service IT projects was provided by the Company.

17 Importantly, Cloud Health and Safety and Enhanced Document Management
18 Capabilities are on Exhibit A-12, Schedule B5.7.1 (Corporate Applications) IT
19 projects. Similar to what was provided in the discovery response AGDE-3 Question
20 No.123 for Customer Services IT projects, please refer to Exhibit A-46, Schedule
21 KK2 for B5.7.1 2024-2025 projects of \$3M or greater.

22 As explained above and supplied in Rebuttal Exhibit A-46, Schedule KK2, the
23 Company provided the requested information that was improperly referenced in the
24 AGDE-3, Question No. 123, along with correct information for the Cloud Health
25 and Safety and Enhanced Document Management Capabilities projects. Hence, the
26 AG's requests for a disallowance of the Capital cost for Cloud Health & Safety of
27 \$2,518,000 for 2024 and \$582,000 for 2025 and Enhanced document management

Line
No.

1 Capital cost of \$1,218,000 for 2024 and \$2,958,000 for 2025 should be completely
2 rejected because the projects are adequately supported in the record.

3

4 **2023 IT Capital Expenditure:**

5 **Q22. What disallowance did AG Witness Coppola propose related to 2023 IT**
6 **Capital Expenditure?**

7 A22. On page 49, lines 17-18 and page 50 lines 1-3, AG Witness Coppola proposed a
8 \$34.85 million disallowance for the IT Capital expenditure in Exhibit A-12
9 Schedule B5.7.

10 **Q23. What reasons did AG Witness Coppola provide for this proposed**
11 **disallowance?**

12 A23. On page 49 lines 14-18 and age 50 line 1, AG Witness Coppola direct testimony
13 states:

14 In discovery, the Attorney General asked the Company to provide the actual
15 amount of capital expenditures incurred in 2023 in the Information
16 Technology area. The information provided in response to the discovery
17 request shows that for 2023 the Company incurred actual capital expenditures
18 of \$127,456,000. In comparison, the Company had forecasted \$162,310,000
19 for the year in Exhibit A-12, Schedule B5.7. The difference of \$34,854,000
20 should be removed from rate base in this rate case.

21

22 **Q24. Do you agree with AG Witness Coppola's recommendation when comparing**
23 **DTE Electric's Forecasted 2023 IT Capital Expenditure with 2023 Actual**
24 **amount?**

25 A24. No, I do not agree. In Exhibit AG-15, AG Witness Coppola utilized incomplete
26 information derived from Exhibit A-12, Schedule B5.7 that was provided in

Line
No.

discovery response AGDE-3, Question No. 122. AG Witness Coppola has made an incorrect comparison of the 2023 total Capital expenditure projected in U-21534 Capital Exhibit A-12, Schedule B5.7, page 1, to the 2023 Shared Assets actuals provided as part of AGDE-3, Question No.122, Exhibit A-12, Schedule B5.7, page 3. For an appropriate comparison the 2023 total Capital expenditures of \$162,310,00 in Exhibit A-12, Schedule B5.7, page 1, must be compared to the 2023 total actual costs of \$177,344,00 provided in response to AGDE-3 question No.122 Exhibit A-12, Schedule B5.7, page 1.

Table 3 : 2023 Capital Projected Vs 2023 Actuals

Total 2023 Projected IT Capital Costs Exhibit A-12, Schedule B5.7, page 1 Forecast	Total 2023 IT Actuals Costs AGDE-3 Q.122 Exhibit A-12, Schedule B5.7, page 1
\$162,310,000	\$177,344,000

Per the information shown in Table 3, which is also being provided as part of Exhibit A-46, Schedule KK3, Complete AGDE-3.122 response, the \$34.85 million Capital disallowance is due to an incorrect data comparison by AG Witness Coppola and should be fully rejected.

Q25. Should the Commission accept AG Witness Coppola recommendation for \$34.85 million?

A25. No, the Commission should reject AG Witness Coppola's recommendation for \$34.85 million based on the clarification provided above.

Line
No.

1 **Q26. Please describe MEIU Witness Barnes’ understanding of DTE Electric’s IT**
2 **APC process and how it relates to the Company’s proposed deployment**
3 **timeline?**

4 A26. On page 21 lines 9-17, Witness Barnes direct testimony states:

5 Witness Sharma describes the APC generally as representing “how the
6 Company refines its investment strategies, establishes financial targets, and
7 sanctions work,” which it further states also applies to IT investments. As
8 witness Sharma describes it, a central aspect of this process is the use of a
9 Project Prioritization Score (“PPS”) that relies on various inputs intended to
10 reflect alignment of investments with the Company’s strategies and goals. In
11 other words, DTE describes this exercise as a “benefits analysis”, stating “The
12 result of this benefit analysis is a Project Prioritization Score (PPS).” However,
13 witness Sharma states that so-called “nondiscretionary
14 Regulatory/Compliance... projects are considered “must-do” and therefore do
15 not require a benefit analysis.

16

17 **Q27. Do you agree with MEIU Witness Barnes’ conclusion regarding DTE**
18 **Electric’s Annual Planning Cycle and Prioritization process?**

19 A27. No, I do not. Witness Barnes’ understanding of the Company’s methodology for
20 prioritization of projects is incorrect. As mentioned in the DTE Five-Year IT Plan
21 2021-2025 filed in Docket No. U-20561, DTE’s vision for IT (across both its
22 electric and gas utilities) is to enable customer affordability and deliver value faster
23 to customers and communities by removing process, human, and technology
24 friction. Therefore, improving efficiency and reducing barriers using IT.

25 As mentioned in Witness Sharma Revised Direct Testimony, page 7, all non-
26 Discretionary and Discretionary investments and IT projects proceed through the
27 complete DTE IT APC Cadence. The APC is how the Company refines its
28 investment strategies, establishes financial targets, and sanctions work. Non-
29 Discretionary demands (which includes Sustainment, Return to Health and

Line
No.

1 Regulatory and Compliance investments) are considered “must-do’s” and assigned
2 a standard score based on the associated investment category.
3 Regulatory/Compliance investments are categorized as non-Discretionary due to
4 the importance and risk tied to a regulation or order from the Commission/other
5 regulatory bodies. Therefore, an order is a major component in determining the
6 investment type and the PPS score within IT’s APC.

7

8 Also, Discretionary projects undergo a more rigorous analysis and review of both
9 qualitative and quantitative benefits across seven weighted benefit categories for
10 prioritization. The result of this benefit analysis is a PPS. The APC process and PPS
11 scoring consider factors such as strategic fit, financial impact, and operational
12 impact before a project is approved. The PPS score is a scoring and ranking
13 methodology used to bring consistency to how projects across multiple investment
14 portfolios are assessed. Scope for IT non-Discretionary and Discretionary projects
15 must be processed through the IT organizations APC. Once this is completed
16 through the APC project approval process, the requirements will be gathered, and
17 a project implementation timeline will be developed.

18

19 **Q28. Does this conclude your rebuttal testimony?**

20 A28. Yes, it does.

1 JUDGE WALLACE: All right. Please go
2 ahead, Mr. Janiszewski.

3 MR. JANISZEWSKI: Thank you, your Honor.
4 Next, the Company moves to bind into the record the
5 Qualifications and Revised Direct Testimony of Michael J.
6 Hatsios, consisting of a cover sheet and 116 pages of
7 questions and answers. The Company also moves for the
8 admission of the following 12 direct exhibits that
9 accompanied Mr. Hatsios's revised direct testimony,
10 marked as Exhibit A-12 Schedule B5.7.3, Exhibit A-13
11 Schedule C5.7, Exhibit A-13 Schedule C5.9.2. I will note
12 that exhibit was cosponsored by Ms. Bennett. Exhibit
13 A-24 Schedule N1.1, Exhibit A-24 Schedule N2, and that
14 specific exhibit was cosponsored by Mr. Sharma. Exhibit
15 A-24 Schedule N3.1, Exhibit A-24 Schedule N5, Exhibit
16 A-24 Schedule N6, Exhibit A-24 Schedule N7, Exhibit A-24
17 Schedule N8, Exhibit A-24 Schedule N9, and Exhibit A-24
18 Schedule N10. The Company also moves to bind into the
19 record the Rebuttal Testimony of Michael J. Hatsios,
20 consisting of a cover sheet and 29 pages of questions and
21 answers. The Company also moves for the admission of the
22 one rebuttal exhibit sponsored by Mr. Hatsios, marked as
23 Exhibit A-44 Schedule II1. And there are no changes to
24 Mr. Hatsios's testimony or exhibits.

25 JUDGE WALLACE: O.K. Is there any
Penn Reporting, LLC - lori.penn@yahoo.com

1 objection to binding in the revised direct testimony of
2 Mr. Hatsios?

3 Hearing none, the testimony is bound in.

4 Is there any objection to binding in the
5 rebuttal testimony of Mr. Hatsios?

6 Hearing none, the testimony is bound in.

7 Is there any objection to the admission
8 of the exhibits and associated schedules sponsored by
9 Mr. Hatsios, sponsored or cosponsored by Mr. Hatsios?

10 Hearing none, we will admit those
11 exhibits once we've bound in the entire, the Company's
12 case.

13 (Testimony bound in.)

14 - - -

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.

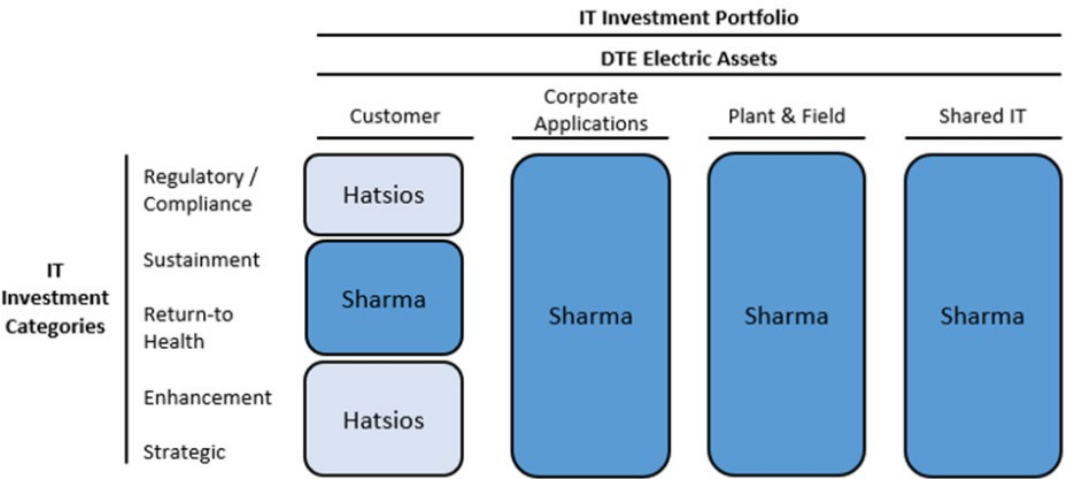
1 A9. Yes, they were. I co-sponsor Exhibit A-24, Schedule N2, with Company Witness
2 Sharma and Exhibit A-13, Schedule C5.9.2 with Company Witness Bennett.

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

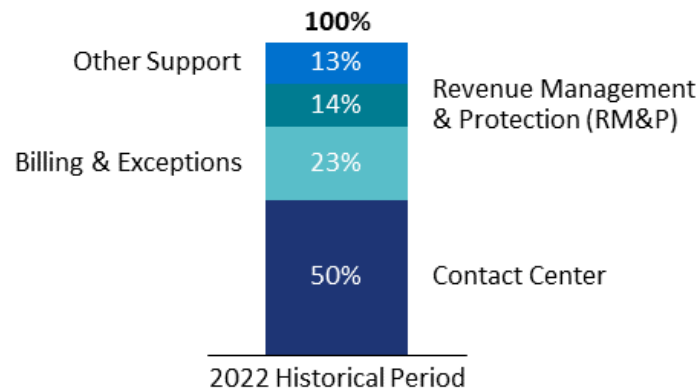
16 **Q18. What is the Company's motivation to reduce the volume of calls handled by**
17 **CRs in its Contact Center?**

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

4

5

6

7

8

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 \$11.34/call results in tens of millions of dollars in DTE Contact Center O&M expense, which is passed on to customers through the utility ratemaking process. As such, reducing calls represents a significant opportunity for the Company to reduce its operating costs and the associated O&M expense that is passed on to customers.

16

17

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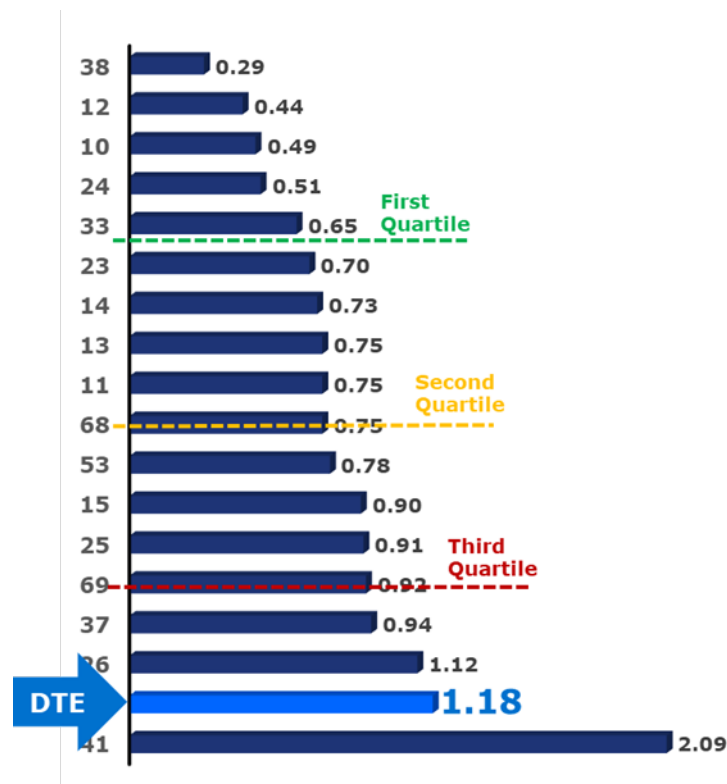
1 Additionally, with fewer live calls to handle, the Company can sustain its desired
2 service levels (e.g., average speed of answer, call abandon rates), and CRs will have
3 the capacity to more effectively handle those more complex inquiries from
4 customers that may not be as effectively handled in 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
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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.

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.

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
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1 5. Outage – Calls from customers who are reporting an electric outage or checking
2 on the status of a reported electric outage.

3

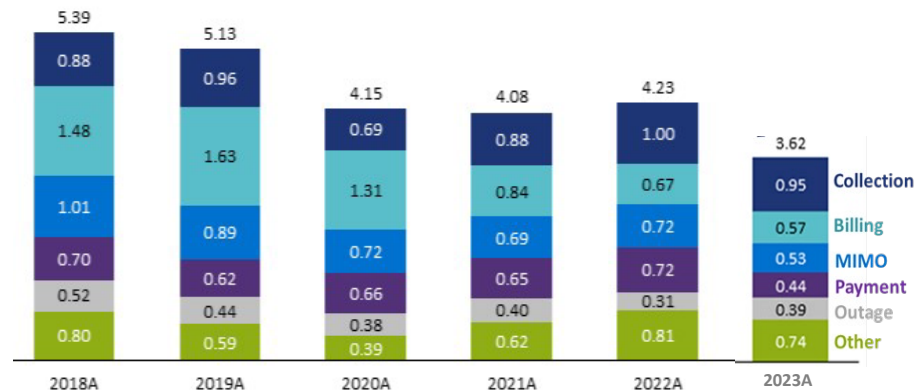
4 **Q22. How has the total volume of calls been trending in the past five years?**

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
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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.

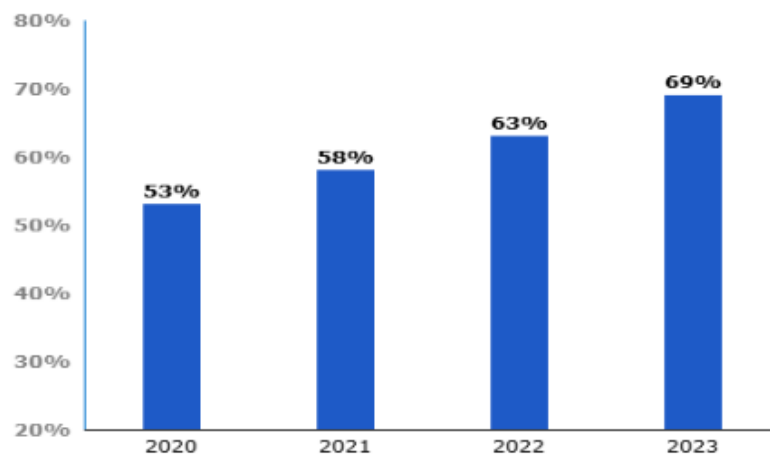
11

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 **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.

1 December 31, 2025, consisting of \$4.4 million in 2022 historical period, \$8.9
2 million in 2023-2024 bridge period, and \$2.5 million in 2025 test period capital, as
3 shown in Exhibit A-12 Schedule B5.7.3, which I have summarized in Table 5
4 below. See Exhibit A-24 Schedule N3.1 Lines 25-26, 39-40, 41, 58-60 for
5 additional project details.

6

7 Note that \$0.4 million of the total \$2.8 million in 2022 historical spend for the
8 Customer Relationship and Billing (CR&B) Enhancement project was allocated to
9 the digital projects, with \$0.2 million allocated to MIMO. \$3.0 million of the \$6.8
10 million in 2022 historical capital for the Journey Work Product Transformation
11 Teams project was also allocated to MIMO digital solutions.

12

13 **Table 5. MIMO Digital Self-Service Capital (\$000s)**

14

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

15 *Net of 2023 reduction of (\$109,000), as shown in Exhibit A-12, Schedule B5.7.3

16

17 **Q35. Can you elaborate on the scope of work that is being funded by the MIMO**
18 **digital self-service capital?**

19 A35. Yes. The focus for the MIMO digital self-service solutions in 2022-2023 was to
20 enhance the existing MIMO Web, and MIMO start service Virtual Assistant (VA),
21 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,

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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

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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.

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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

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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

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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.

24

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

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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.

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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

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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).

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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?**

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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

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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

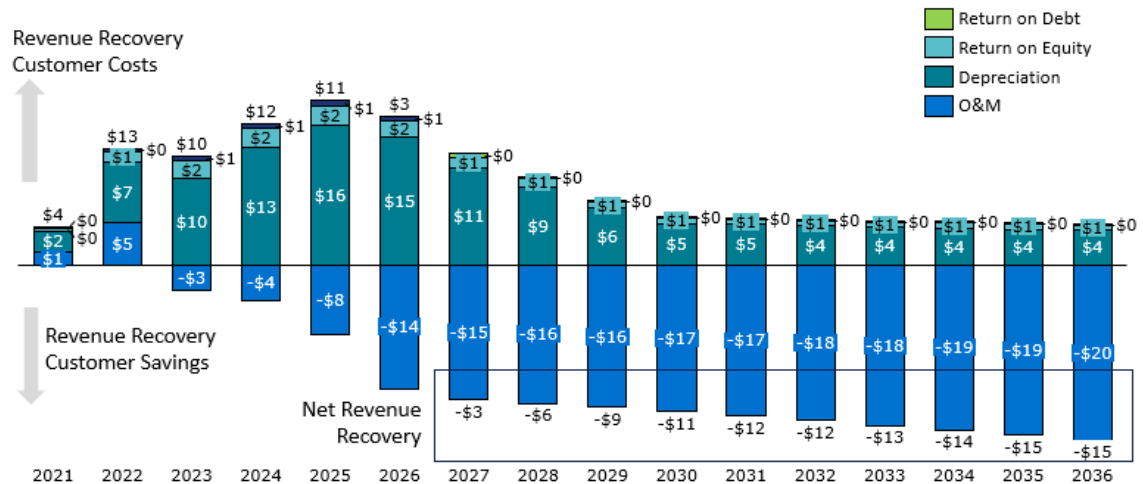
20 **Q53. What is the NPV of the Company's digital self-service projects?**

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.

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Figure 8 - Digital Self-Service Project NPV (\$ millions)

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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

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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.

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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,

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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

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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

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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

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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.

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3. 2025 AA Use Case - Automating CR Notes – \$2.0 million

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22

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?

23

24

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

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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
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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

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- 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
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- 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
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- 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
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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
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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
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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

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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

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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

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1 the customer's power status. However, timeliness of identifying the customer's
2 power status could be delayed with the use of AMI data, so a new metric was
3 developed to ensure timely delivery of power status updates – Restoration
4 Communication within 1-hour. In 2023, 41.5% of customers who were restored
5 received confirmation of their restoration within 1-hour, which the Company is
6 forecasting to increase to 65% in 2024, while maintaining 99% Power Restoration
7 Accuracy, and for which the Company has established a long-term target of 90%.

8

9 First Estimate Accuracy

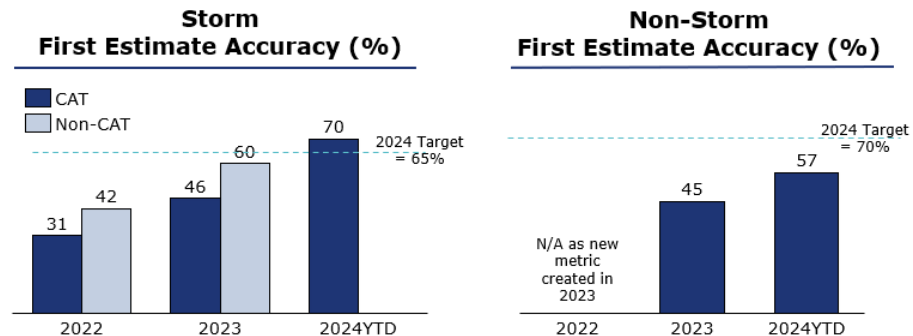
10 One of the most significant drivers of customer dissatisfaction during an outage is
11 the lack of an accurate restoration estimate. As such, one of the key elements of
12 the EFC – Outage Status initiatives is to improve the timeliness and accuracy of the
13 first Estimate Time of Restoration (ETR) that is delivered to the customers. Our
14 leading metric, First Estimate Accuracy, measures the percent of customers that
15 received a single and accurate estimated restoration time (ETR). The Company
16 measures First Estimate Accuracy based on the restoration estimate information
17 provided to our customers. In Non-Storm conditions, customers receive a day and
18 time estimate, while in Storm conditions customers receive a day-level estimate.
19 During a storm, an estimate is accurate if the customer receives a single estimate
20 communication and is restored the same day as the day provided in the estimate.
21 The Company defines First Estimate Accuracy more stringently during a Non-
22 Storm day, as the customer must receive a single estimate and be restored no earlier
23 than 3 hours prior and no later than 10 minutes past the estimate communicated.¹
24 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.

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metric, achieving the highest catastrophic storm accuracy rate to date in the January 2024 CAT storm (Figure 9).

Figure 9 - Improvement in First Estimate Accuracy



As seen in Figure 9, we have improved our first estimate accuracy between 2022 and 2023 by 48% for catastrophic storms (CAT) from 31% to 46%, and by 43% for non-catastrophic storms (Non-CAT) from 42% to 60%. Additionally, during the January 2024 CAT storm, we performed at 70%, which is above our 2024 Target of 65% for all storms. Similarly, the Company has realized improvements in estimate accuracy for Non-CAT storms, which has increased from 45% in 2023, to 57% in 2024. I would note here that because the Company changed the way we define Non-CAT estimate accuracy in 2023, there is no comparative data for 2022 performance. Long-term, the Company is targeting 95% First Estimate Accuracy during all storms, and is targeting delivery of those estimates within 4-hours of the storm weather clearing, and within 1-hour during non-storms.

Additionally, we have improved our estimate delivery timeliness—the amount of time between the weather clearing the service territory and the time outage-specific

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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

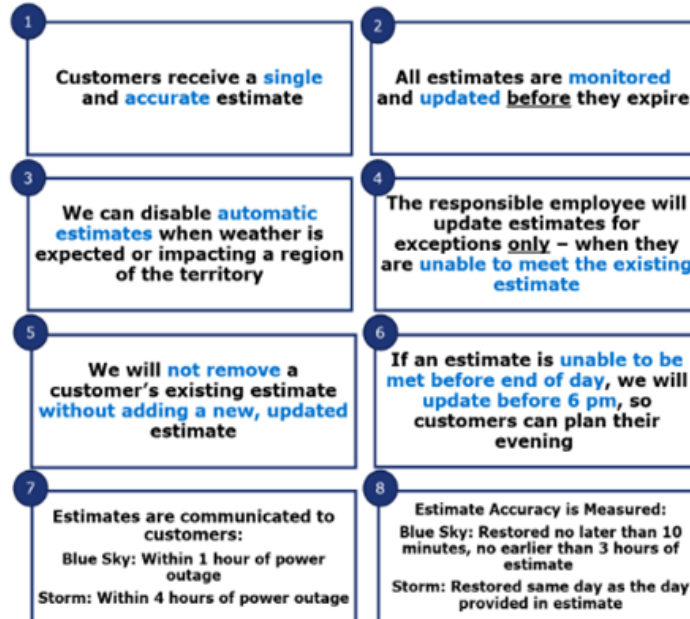
22 The Company is investing \$1.1 million in the 2023 and 2024 bridge period, and
23 \$0.3 million in the 2025 test period, capital in its Restoration Estimate initiative,
24 which leverages a standardization of processes and machine learning models to
25 achieve its long-term estimate accuracy goals and objectives. This \$1.4 million in

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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.

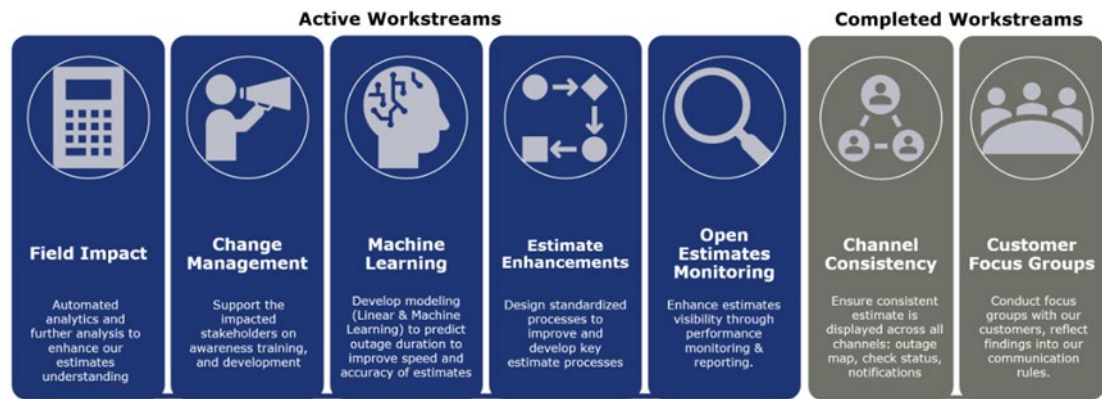
4
5 There are eight defining guiding principles (Figure 10), which have informed the
6 creation of seven Restoration Estimate workstreams (Figure 11), two of which have
7 been completed, that support the continuous improvement of restoration estimates
8 to accelerate achievement of the Company's long-term 95% First Estimate
9 Accuracy target, and the timeliness by which estimates are communicated to
10 customers.

12 **Figure 10 - Restoration Estimate Guiding Principles**



Line
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Figure 11 - Restoration Estimates Initiative - Workstreams

2

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18

During non-storm outages, our outage management system generates an estimate based on an algorithm and sends it within 1 hour to our customers. And while we have improved First Estimate Accuracy significantly in 2023 (Figure 9), the continued use of a manual process during storms to generate restoration estimates means that many customers go for prolonged periods of time without an estimate, especially during CAT storms.

To reduce the amount of time required to provide customers a restoration estimate during storms, a team of data scientists has developed several versions of a restoration estimate machine learning model and are in the process of validating them against historical storm data. Once fully developed, the machine learning model will improve the timeliness of delivering storm estimates by being able to process a significant volume of historical data, such as the number of customers out, location, weather, and other environmental factors, without human intervention to generate an estimate. The chosen model will be used in the summer of 2024 to generate restoration estimates alongside our existing manual method to gauge the

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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

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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.

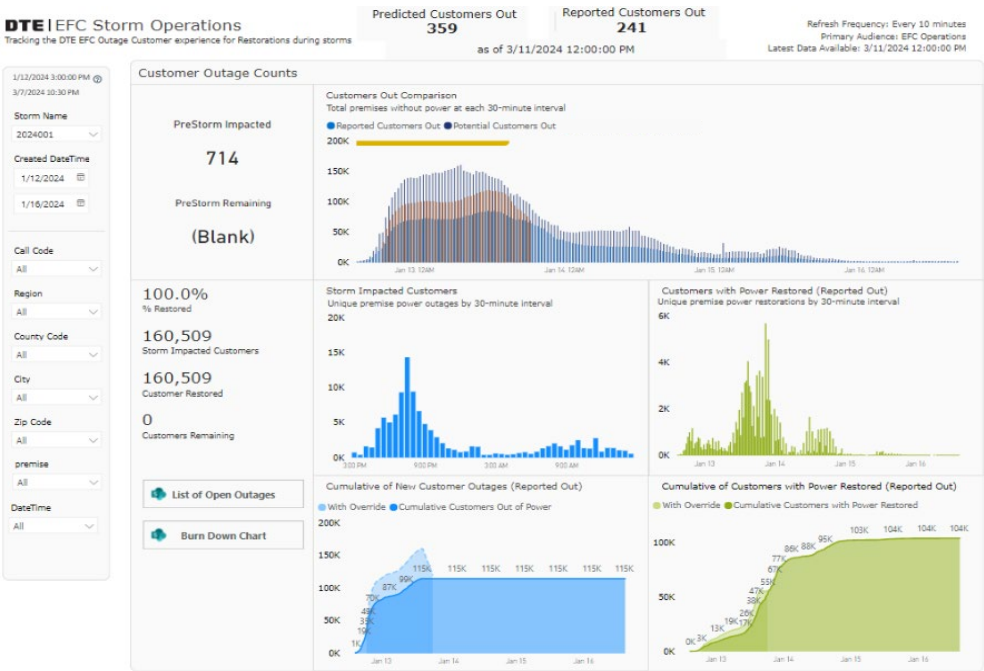
14
15 Lessons learned from the use of these dashboards in 2023 informed opportunities
16 for enhancements in 2024 that will allow the Company to be more proactive and
17 aware during a storm, allowing it to better prioritize its restoration and
18 communication efforts. Examples of the 2023 enhanced dashboards are in Figures
19 12 and 13 below.

20

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1

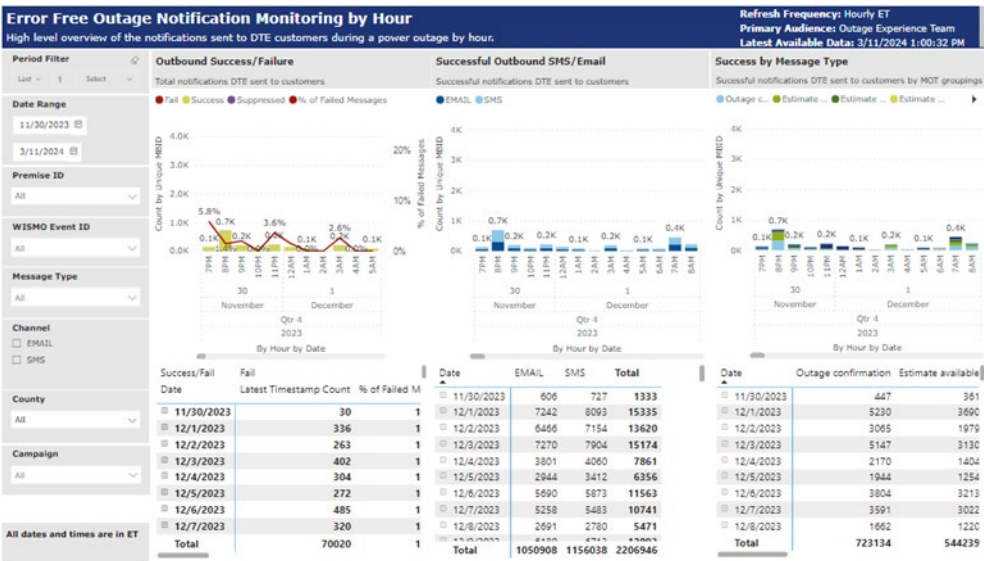
Figure 12 - Customer Outage Status Dashboard



2

3

Figure 13 - Customer Outage Notifications Dashboard



4

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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

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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
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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
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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

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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
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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

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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.

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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.

Line
No.

1

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.

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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

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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
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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)

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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.

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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

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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

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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

REBUTTAL TESTIMONY

OF

MICHAEL J. HATSIOS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MICHAEL J. HATSIOS

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

3 A1. My name is Michael J. Hatsios (he/him/his), and my business address is One
4 Energy Plaza, Detroit, Michigan, 48226. I am employed as Director - Customer
5 Service Operations by DTE Energy Corporate Services, LLC, a subsidiary of DTE
6 Energy.

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. The purpose of my testimony is to rebut the following intervenor recommended
15 Customer Information Technology (IT) capital disallowances:

16

17 1. Attorney General (AG) Witness Coppola's recommended \$21.2 million
18 disallowance of the four Customer IT capital projects shown in Exhibit A-12,
19 Schedule B5.7.3 on lines 4, 11, 14, and 18, which includes \$5.8 million in the
20 2024 bridge period and \$15.4 million in the 2025 test period.

21

22 2. AG Witness Coppola's recommendation to remove the \$5.8 million of working
23 capital for the Time-of-Day (TOD) project shown on line 27 of Exhibit A-12,
24 Schedule B4, and \$1.7 million and associated amortization expense from the
25 Company's projected 2023 costs included in the deferred regulatory asset.

Line
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1 3. Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy
2 Organization or DAAO) Witness Koeppel's and Witness Jacob's recommended
3 disallowance of \$10.7 million in 2022-2025 IT capital to fund the Collection
4 Digital Self-Service projects. These capital dollars, and the projects with which
5 they are aligned, are summarized at page MJH-21, Table 3 of my revised direct
6 testimony. My rebuttal to the proposed disallowances will also include a
7 response to Witness Koeppel's views on the value of digital self-service
8 investments and to Witness Jacob's opinion about the effectiveness of our
9 digital self-service tools, specifically the DTE Kiosks and automated messages,
10 in serving low-income customers. I will also provide a response to Witness
11 Jacob on the importance of DTE Electric offering phone service to low-income
12 and vulnerable customers.

13

14 I will also be providing responses to certain questions, concerns, and assertions that
15 were expressed by the intervenors in Case No. U-21534 related to the following:

16

17 1. DAAO Witness Koeppel's assertion that there has been a significant increase
18 in the Company's request for IT capital recovery in the instant case.

19

20 2. Michigan Energy Innovation Business Council, the Institute for Energy
21 Innovation and Advanced Energy United, collectively referred to as MEIU,
22 Witness Barnes' recommendations related to the timing of the implementation
23 of Commercial and Industrial Time-of-Use (C/I TOU) rates and supporting
24 analysis tools.

25

Line
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1 3. Michigan Municipal Association for Utility Issues (MI-MAUI) Witness
2 Bunch's concerns regarding the safety of making a payment at a DTE Kiosk
3 and the geographical locations where the kiosks are located.
4

5 Finally, I will be providing a response to Michigan Public Service Commission
6 (MPSC or Commission) Staff (Staff) Witness Klocke's request that DTE Electric
7 further describe and provide regular updates to Staff and the Commission regarding
8 its on-going efforts to improve the outage customer experience and achieve the
9 long-term goals for key performance metrics as part of the Error Free
10 Communications (EFC) – Outage Status project.
11

12 The absence of a discussion of any other matters not listed above, and not included
13 in my rebuttal testimony, should not be taken as an indication of agreement with
14 other aspects of any witness's testimony in the instant case.
15

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

17 A4. Yes, I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-44	II1	2024 – 2025 Collection Self-Service Enhancements

20

21 **Q5. Was the exhibit prepared by you or under your direction?**

22 A5. Yes, it was.
23

Line
No.

1 **Attorney General (AG) - IT Project Capital Disallowances**

2 **Q6. What disallowances does AG Witness Coppola recommend with respect to the**
3 **Company's Customer IT capital projects?**

4 A6. AG Witness Coppola at page 47, lines 1 through 18 at page 48, and lines 1 through
5 2 of his direct testimony, recommends disallowances of \$5.8 million and \$15.4
6 million for forecasted 2024 and 2025 capital expenditures, respectively, for four
7 Customer IT capital projects. The four projects explicitly recommended for
8 disallowance in Witness Coppola's direct testimony include the three Michigan
9 Green Power (MIGP) projects shown in Exhibit A-12, Schedule B5.7.3, on lines 4,
10 11, and 15, and the 2025 Advanced Analytics (AA) Use Case for Reducing MPSC
11 Complaints, which represents \$1.0 million of the total \$3.0 million in capital for
12 the 2025 AA Use Cases Implementation project in Exhibit A-12, Schedule B5.7.3,
13 on line 18.

14
15 Witness Coppola is also recommending at page 64, lines 15 through 17 of his direct
16 testimony the reduction of \$5.8 million in TOD working capital, and \$1.7 million
17 in amortization expense, related to the TOD Deferred Asset as calculated in Exhibit
18 A-13, Schedule C5.9.3.

19

20 **Q7. What is the basis of AG Witness Coppola's proposed disallowance of**
21 **forecasted IT capital expenditures totaling \$21.2 million for four Customer IT**
22 **projects?**

23 A7. The basis for Witness Coppola's recommended disallowance of these four projects
24 is his assertion at page 47, lines 16 through 18 of his direct testimony that "these
25 projects have not yet started the initial scoping phase, are in the early phase of

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1 development, or will not be completed by the end of the projected test year”, and
2 therefore, he maintains that it would be premature to include the forecasted IT
3 capital expenditures in rate base.

4

5 **Q8. What is the basis for AG Witness Coppola’s recommended TOD working**
6 **capital and amortization expense adjustment?**

7 A8. Witness Coppola’s recommended adjustment of the TOD working capital is based
8 on his assertion at page 63, line 19 through page 64, line 8 of his direct testimony
9 that “in neither its filed testimony nor in its exhibit, did the Company provide any
10 evidence that the costs incurred in 2022 and forecasted for 2023 were reasonable
11 and prudent” and that in its response to the AG’s discovery request to provide
12 specific costs incurred over \$100,000, the Company provided “no itemized list of
13 actual costs or calculations as to how it arrived at the forecasted costs”. As such,
14 Witness Coppola is recommending the removal of \$5.8 million in 2023 TOD
15 working capital and the associated \$1.7 million in amortization expense from the
16 Company’s forecasted amounts for the projected test year at page 64, lines 15-17
17 of his direct testimony.

18

19 **Q9. Do you agree with AG Witness Coppola that the capital for the four Customer**
20 **IT projects for which he is recommending disallowance totals \$21.2 million?**

21 A9. No, I do not. As a threshold matter, Witness Coppola has over-stated the 2024 and
22 2025 capital dollars associated with the four IT capital projects for which he is
23 recommending for disallowance. In his direct testimony in Case No. U-21534, at
24 page 47, lines 9 through 14 on, Witness Coppola identifies each of the specific
25 capital projects for which he is recommending a disallowance, which includes: (1)

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1 the MIGP Customer Requested Renewable Energy Project, (2) the MIGP Scope 3
2 Billing and Enrollment project, (3) the Rider 17- MIGreenPower Residential and
3 Commercial project (MIGP Rider 17), and (4) the 2025 Advanced Analytics Use
4 Case for Reducing MPSC Complaints. Witness Coppola states in his direct
5 testimony, and includes in his supporting Exhibit AG-18, line 27, that the capital
6 expenditures for these four projects are \$5.75 million for 2024 and \$15.39 million
7 for 2025. However, the total \$21.2 million in 2024-2025 capital dollars that
8 Witness Coppola is recommending for disallowance for these four projects are not
9 aligned with the actual dollars for which the Company is seeking recovery, as they
10 are reflected in Exhibit A-12, Schedule B5.7.3 or as described in my revised direct
11 testimony.

12

13 Witness Coppola has inadvertently included in his capital totals \$2.00 million for
14 the 2024 Advanced Analytics Use Cases Implementation project (described at page
15 MJH-40, lines 12 through 24 and page MJH-50, line 6 through MJH-51, line 4 of
16 my revised direct testimony), and \$2.01 million in 2025 IT capital for the other
17 2025 Advanced Analytics Use Case described at page MJH-52 lines 2 through 20
18 of my revised direct testimony, neither of which is he recommending for
19 disallowance in his direct testimony. As such, the total capital associated with the
20 projects for which Witness Coppola is recommending for disallowance is \$3.75
21 million in 2024 and \$13.39 million in 2025.

22

23 **Q10. Given your response to Q9, which capital disallowances related to the four**
24 **Customer IT projects are you rebutting?**

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1 A10. I will be rebutting Witness Coppola's proposed disallowance of the \$3.75 million
2 in 2024 IT capital associated with the MIGP Customer Requested Renewable
3 Energy Projects (\$2.25 million) and MIGP Rider 17 project (\$1.50 million), the
4 \$8.49 million in 2025 IT capital associated with the MIGP Customer Requested
5 Renewable Energy Projects (\$5.49 million) and the MIGP Rider 17 project (\$3.00
6 million), and finally, the \$1.00 million in 2025 IT capital associated with the 2025
7 Advanced Analytics Use Case for Reducing MPSC Complaints as it is described at
8 page MJH-51, lines 6 through 25 of my revised direct testimony. I will not be
9 rebutting Witness Coppola's recommended disallowance of the \$3.9 million in
10 2025 IT capital associated with the MIGP Scope 3 Billing and Enrollment project,
11 as this project has been rescheduled to begin in 2026 to align with the go-live dates
12 of new renewable energy generation capacity in 2026, and as such, the Company is
13 withdrawing its request for recovery of this capital in the instant case.

14

15 **Q11. Why are you rebutting AG Witness Coppola's disallowance of the 2024 and**
16 **2025 capital for the MIGP Customer – Requested Renewable Energy Projects**
17 **(Exhibit A-12, Schedule B5.7.3, line 4)?**

18 A11. As described in my revised direct testimony on page MJH-86, line 10 through MJH-
19 87, line 7, the Company is investing \$2.7 million in the 2023-2024 bridge period,
20 and \$5.5 million in the 2025 test period capital in the MIGP Customer-Requested
21 Renewable Energy Projects. The capital requested reflects a variance of \$4.6
22 million less in the 36 months ending December 31, 2024, than what was approved
23 for cost recovery in U-21297 as the project has been pushed out to 2025 due to a
24 delay in the construction of these projects, which is reflected and in alignment with
25 the project timeline provided on page 5 of Exhibit AG-13. The requested capital

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1 for this project represents two unique contracts with two companies to build two
2 dedicated solar parks with 650 MW and 400 MW of capacity, respectively, to offset
3 the customers' electricity use with green energy. Given the prior approval of the
4 project capital in Case No. U-21297 as a Level 2 project (MPSC Staff Exhibit S-
5 12.3, page 1, line 40) and the contracted nature of these projects, the Company is
6 mandated and committed to make these investments. Thus, the Commission should
7 reject the AG's proposed disallowance of \$7.7 million in 2024 bridge and 2025 test
8 period capital.

9
10 In regard to Witness Coppola's assertion that the project either has not started, is in
11 the early phase of development, or will not be completed by the end of the projected
12 test year, I would point out that the 2024-2025 project kicked-off on August 1,
13 2024, is in the project initiation phase and progressing per the timetable provided
14 on page 5 of Exhibit AG-13, and is on track to go-live by November 30, 2025. 2024
15 year-to-date capital spend is \$2.0 thousand, and year-end forecasted costs are \$2.3
16 million. There is no change to the 2025 projected test period capital of \$5.5 million.

17
18 **Q12. Why are you rebutting AG Witness Coppola's proposed disallowance of the**
19 **2024 and 2025 capital for the Rider 17 – MIGP, Residential and Small**
20 **Commercial & Industrial Project (Exhibit A-12, Schedule B5.7.3, line 15)?**

21 A12. As described in my revised direct testimony on page MJH-90, lines 8 through 22,
22 the Company is investing \$1.9 million in the 2023-2024 bridge period and \$3.0
23 million in the 2025 test period capital in the Rider 17 – MIGreenPower, Residential,
24 Small Commercial, and Industrial project. This capital reflects a variance of \$1.9
25 million less in the 24 months ending December 31, 2024, than was approved for

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1 cost recovery in Case No. U-21297. This is because the planned work could not
2 start until after the Commission approved the project in November 2023. Given
3 the regulatory nature of this project and the prior approval of the project capital in
4 Case No. U-21297 as a Level 2 project (MPSC Staff Exhibit S-12.3, page 1, line
5 39), the Company is mandated and committed to make these investments; hence,
6 the Commission should reject the AG's proposed disallowance of \$4.5 million in
7 2024 bridge and 2025 test period capital.

8

9 Regarding Witness Coppola's assertion that the project either has not started, is in
10 the early phase of development, or will not be completed by the end of the projected
11 test year, the 2024 project kicked-off in February 2024 and is in the first Testing
12 phase with Development continuing and additional Testing to come. Thus, it is not
13 pre-mature to request recovery for this project. We are progressing per the timetable
14 to go-live by November 30, 2024, and have spent \$0.4 million in 2024 year-to-date
15 capital and are forecasting to spend \$1.5 million by year-end.

16

17 Also, while the Company provided project phases and associated timeline for the
18 2024 and 2025 projects separately in our discovery response to the AG, as shown
19 on page 5 of Exhibit AG-13, this project is essentially one multi-year project with
20 annual releases of system enhancements based on customer demand for renewable
21 energy and energy market pricing. Thus, the 2025 project is not a stand-alone
22 project, and hence the project is well beyond the initial design or early development
23 stage of maturity. The 2025 project phase will start in January 2025, as reflected on
24 page 5 of Exhibit AG-23, which aligns with when annual funding of IT capital is

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1 available. There is no change to the go-live date by November 30, 2025, or in the
2 2025 projected test period capital of \$3.0 million.

3

4 **Q13. Why are you rebutting Witness Coppola's disallowance of the 2025 IT capital**
5 **for the Advanced Analytics Use Case for Reducing MPSC Complaints**
6 **project?**

7 A13. As described in my revised direct testimony at page MJH-51, lines 6 through 25,
8 the Company is investing \$1.0 million in capital in the 2025 Advanced Analytics
9 Use Case for Reducing MPSC complaints. This use case will leverage machine
10 learning to model and better understand the drivers of customer MPSC Complaints,
11 with an emphasis on the Billing and Collection transactions, which generate ~80%
12 of the total Customer Service MPSC Complaints. In addition to reducing MPSC
13 Complaints by 15% over a five-year period starting in 2026 through proactive
14 customer outreach, it will also improve the visibility for customer representatives
15 (CRs) in the Contact Center to use the information provided by the model to better
16 manage customer inquiries and provide higher quality service.

17

18 In regard to Witness Coppola's assertion that the project either has not started, is in
19 the early phase of development, or will not be completed by the end of the projected
20 test year, I would point out that, as provided on pages 4 through 5 of Exhibit AG-
21 13, the 2025 Advanced Analytics Use Case to reduce MPSC Complaints project is
22 on track to start in March 2025, which aligns with when analytics resources would
23 be available to start this project, with no change to the go-live date by December
24 12, 2025, or in the 2025 projected test period capital of \$1.0 million. Furthermore,
25 initial scoping has been completed and data preparation to bring complaints data

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1 into our DTE cloud platform is underway. Due to the extensive data and data
2 engineering requirements of the project, work has begun in 2024 to ensure the
3 timely kick-off of the modeling phase of the project in March 2025.

4

5 **Q14. Do you agree with AG Witness Coppola's recommendation to remove the**
6 **\$5.8 million in 2023 TOD working capital and the associated \$1.7 million in**
7 **amortization expense?**

8 A14. No, I do not. In Case No. U-21297, the Company provided the projected cost for
9 the TOD project to be \$2.4 million in 2022 and \$6.1 million in 2023, for a total cost
10 of \$8.5 million for the deferred asset. The final order in Case No. U-21297
11 approved the working capital and the related \$1.7 million in amortization expense.

12

13 In the instant case, the Company provided the actual costs of \$2.0 million for 2022
14 and projected cost of \$6.5 million for 2023, for a total of \$8.5 million, resulting in
15 the amortization of \$1.7 million per year. On an overall basis, there was minimal
16 change in the total 2022 and 2023 TOD project O&M costs.

17

18 Differences in 2022 and 2023 costs between Case No. U-21297 and Case No. U-
19 21534 included reductions or offsets across Information Technology (IT),
20 Customer Outreach and Customer Service. The 2022 variance between actual costs
21 in Case No. U-21534 and projected costs in Case No. U-21297 involved a reduction
22 in all three TOD expense line items, resulting in a \$0.4 million reduction after
23 accounting for TOD expenses prior to November 18, 2022. Projected costs for
24 2023 in Case No. U-21534 increased by \$0.4 million in total, largely due to
25 Customer Service overtime labor that was partially offset by a decrease in IT and

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1 Customer Outreach spending. The Customer Service overtime labor costs were
2 required to perform billing and AMI meter rate conversion pre-work, manual
3 intervention of placing customers on the new TOD rates, and for processing
4 business exceptions related to delayed bills. Overall, there was essentially no
5 variance in the total TOD costs of \$8.5 million, that was approved for deferral in
6 Case No. U-21297, and therefore, the Commission should reject the AG's
7 disallowance of \$5.8 million on working capital and the associated amortization
8 expense of \$1.7 million.

9

10 **Detroit Area Advocacy Organization (DAAO) - IT Project Capital Disallowances**

11 **Q15. What are DAAO Witness Koeppel's concerns about investments in digital self-**
12 **service programs, and particularly regarding Collection Self-Service?**

13 A15. On page 29, line 10 through page 31, line 2 of Witness Koeppel's direct testimony,
14 he raised several concerns regarding the Company's investment in digital self-
15 service solutions, especially regarding Collection Digital Self-Service. What
16 follows is a summary of Witness Koeppel's concerns:

17

18 1. Witness Koeppel asserts that DTE Electric's proposed IT investments in digital
19 self-service tools for customer collections may be subject to diminishing returns
20 and may not generate the full scale of benefits that the company claims (at page
21 29, lines 11 through 14).

22

23 2. Witness Koeppel asserts that DTE Electric's self-service options may be
24 reaching a saturation point in terms of adoption and utilization since 69% of
25 customer transactions were completed in a digital channel in 2023 as compared

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1 with 53% in 2020, and for the Outage and Payment transactions, they are
2 nearing their long-term digital engagement rate (DER) targets (at page 29, line
3 15 through page 30, line 4).

4

5 3. While Witness Koeppel acknowledges that Collection DER is increasing, he
6 maintains that Collection call volumes are not diminishing (at page 30, lines 4
7 through 5).

8

9 4. Witness Koeppel asserts that the Company's investments in Collection Digital
10 Self-Service do not align with the Commission and other stakeholders' goals of
11 advancing energy affordability, equity, and sustainability (at page 30, lines 6
12 through 9).

13

14 **Q16. How do you respond to DAAO Witness Koeppel's concerns about the**
15 **Company's investments in Collection Digital Self-Service?**

16 A16. The Company rejects each of Witness Koeppel's assertions. What follows are the
17 reasons for the Company's rejection of those assertions:

18 1. The Company rejects Witness Koeppel's assertion that it is seeing diminishing
19 returns from its digital self-service investments and may not generate the full
20 scale of benefits the Company claims. By 2027, the Company is forecasting to
21 reach an overall average DER of 76% across key customer transactions (see
22 Digital Engagement Rate (DER) by Transaction on page 1 of Exhibit A-24
23 Schedule N5, lines 8 through 13, columns (c and d)), which is 7% above the
24 2023 overall DER of 69%. Furthermore, the Company is committing to, as a
25 result of DER increases from 2023-2027, a total of \$9.7 million in 2022-2025

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1 call volume reduction savings, which the Company has removed the DTE
2 Electric portion of \$6.4 million from its requested O&M cost recovery as
3 discussed at page MJH-20, lines 7 through 15 of my revised direct testimony
4 and as shown in Exhibit A-24, Schedule N5, page 1, line 17, column (f), and
5 Exhibit A-13, Schedule C5.7, line 5, column (k). The Company has also
6 committed to removing these call volume reduction savings in future rate cases,
7 providing total cumulative 2022-2027 O&M cost savings of \$15.7 million as
8 shown in Exhibit A-24, Schedule N5, page 1, line 16, column (h).

9

10 2. The Company also rejects Witness Koeppel's assertion that it is reaching a
11 saturation point in customer adoption and utilization of its digital self-service
12 solutions. Although Witness Koeppel is correct that Outage DER is high at
13 94% and 96% in 2022 and 2023, respectively, and hovering near the 2027 DER
14 target of 95%, the Outage DER varies year-over-year based on the volume of
15 storm activity. Regarding Witness Koeppel's comment about Payment DER
16 also nearing its 2027 target of 85% given it reached 84% DER in 2023, a 1%
17 increase in Payment DER is not the same as a 1% increase in the other
18 transactions as our customers make nearly 33 million payments per year, so a
19 1% increase by 2027 is an ambitious goal.

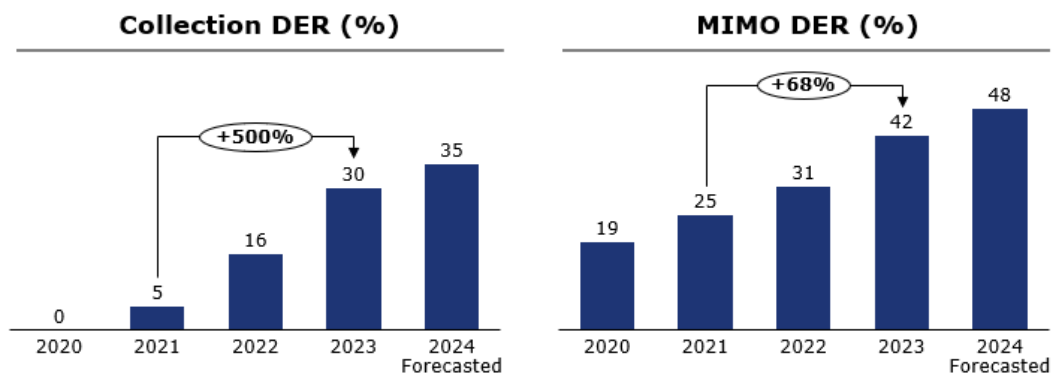
20

21 Furthermore, as seen in Figure 1 below, the Company has seen rapid growth in
22 Collection DER from 2021 to 2023 and how that compares with what we saw
23 over the same period with the Move-in / Move-out (MIMO) transaction, which
24 has also experienced significant DER growth. Adoption of the Collection self-
25 service tools has been much faster and coincides with making Collection self-

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service options (e.g., Restore Electric Service and Payment Extension) available to customers. Also, it is worth noting that the Company has seen rapid adoption of the newly launched (June 2024) Web Payment Agreement (PA) solution, which has already resulted in 7,600 customer PA enrollments (equivalent to 12% of all PA enrollments to-date in 2024). And despite these recent significant increases in both the Collection and MIMO DERs, both transactions remain well below their long-term targets of 60%, as shown in Table 2 at page MJH-18 of my revised direct testimony in the instant case.

Figure 1: 2020-2024 Growth in Digital Engagement



3. The Company rejects Witness Koeppel's assertion that the Collection Digital Self-Service solutions are not contributing to a reduction in call volumes. As described in my revised direct testimony at page MJH-23, lines 3 through 9, in 2023, despite increased numbers of low-income customers, increased numbers of low-income customers entering final arrears, and reduced energy assistance funding, the Company handled 43,500 fewer Collection calls than it did in 2022. This was a direct result of the continued expansion and enhancement of the Company's Collection Digital Self-Service solutions, with customers

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1 increasing their use of these digital solutions from 16% in 2022 to 30% in 2023
2 and 35% year-to-date for 2024, as shown in Figure 1.

3

4 Furthermore, in 2024, we are forecasting to reduce Collection call volume by
5 133,000 calls, having already realized a year-to-date reduction of 77,000 calls.
6 This will bring the total cumulative reduction in call volumes from 2023-2024
7 to 176,500 calls, which is ~50% of the 343,600 cumulative Collection calls we
8 projected to reduce from 2023-2027, providing \$2.0 million in cumulative
9 O&M savings. See annual and cumulative 2023-2027 Collection call volume
10 reduction actuals and projections and associated O&M savings as provided at
11 page 2 of Exhibit A-24, Schedule N5, lines 10 and 18.

12

13 4. Finally, the Company disputes Witness Koppel's assertion that its investments
14 in Collection Digital Self-Service solutions are not aligned with the
15 Commission and other stakeholder goals of improving affordability, equity, and
16 sustainability. The Company maintains that it is providing equitable
17 opportunities for low-income and other vulnerable customers to have access to,
18 and the same opportunity to choose to engage in, the same convenient and easy-
19 to-use Digital Self-Service solutions as any other customer who finds
20 themselves struggling to pay or in some step of the Collection process.
21 Furthermore, as outlined in my revised direct testimony at page MJH-23, lines
22 18 through 24 in the instant case, the realized and forecasted Collection call
23 volume reductions are forecasted to deliver \$3.9 million in cumulative O&M
24 savings from 2023-2027, summarized in Exhibit A-24, Schedule N5, page 1,
25 line 3, column (j). These O&M savings are part of the total \$9.7 million in

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1 2022-2025 call volume reduction savings for which the Company has removed
2 the DTE Electric portion of \$6.4 million from its requested O&M cost recovery
3 as discussed above and at page MJH-20, lines 7 through 15 of my revised direct
4 testimony and as shown on Exhibit A-13, Schedule C5.7, line 5, column (k).
5 Therefore, not only is the Company providing low-income, vulnerable, and
6 other customers with the tools they need to reduce their past-due balances and
7 avoid shut-off, but it is also providing significant O&M savings, which are
8 passed on to all customers through the rate-making process.

9

10 **Q17. What specific aspects of DAAO Witness Koeppel's direct testimony, as it**
11 **relates to his recommended disallowance of the \$10.7 million in IT capital for**
12 **Collection Digital Self-Service, are you rebutting?**

13 A17. I will rebut Witness Koeppel's assertion in his direct testimony at page 31, line 17
14 through page 32, line 8 that the Company's justification for the \$10.7 million capital
15 investment in Collection self-service prioritizes its own financial interests (through
16 earning a return on invested capital) over the needs and well-being of its customers
17 despite being aware of the energy affordability challenges that some of its
18 customers face, and are using ratepayer funds to make its collections process "more
19 automated, efficient and aggressive," and easier for the Company to pursue
20 collections and disconnections. I will also rebut Witness Koeppel's assertion at
21 page 32, lines 12 through 18 of his direct testimony that the Company is more
22 focused on collection efficiency rather than affordability and assistance, which
23 exacerbates the economic and social inequities faced by low-income and
24 marginalized customers and the disproportionate impacts of energy insecurity and
25 utility shut-offs affecting them.

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1

2

Additionally, it is important to accurately set the context for evaluating the

3

Company's \$10.7 million in capital expenditures in the Collection Digital Self-

4

Service projects. Contrary to what Witness Koeppel claims at page 29, lines 4

5

through 8 of his direct testimony, Customer IT capital investments in Case No. U-

6

21534, for which my direct testimony supports, have not significantly increased but

7

have decreased since the last DTE Electric rate case filing in Case No. U-21297.

8

There is also an error in Witness Koeppel's calculation for which I will discuss and

9

rebut in a later section of my rebuttal testimony.

10

11

Q18. How do you respond to DAAO Witness Koeppel's assertion that the \$10.7

12

million in Collection Digital Self-Service capital should be disallowed for the

13

reasons described in his direct testimony?

14

A18. The Company firmly rejects Witness Koeppel's assertion that its investments in

15

Collection Digital Self-Service solutions prioritize the Company's financial

16

interests above the needs of its customers and that these solutions allow the

17

Company to pursue collections and disconnects more easily. The Company has

18

designed every one of its implemented and planned Collection Digital Self-Service

19

solutions with the needs of customers top-of-mind and not to improve the efficiency

20

and convenience of the collection process for the Company, starting with the

21

transactions themselves which make it easier for customers to restore their electric

22

service with full payment of their past-due balance (which represents the majority

23

of all restore electric service orders), request a payment extension to have more

24

time to pay their bill, enroll in a payment agreement to pay their past-due balance

25

over time, or look into their eligibility for energy assistance. These actions may all

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1 be accomplished without human intervention, in a digital channel of their choice
2 and at a time that is most convenient for them, which for some customers is a more
3 comfortable way to interact. And, if the customer prefers, they can call our Contact
4 Center and speak with a customer representative (CR) to handle their Collection
5 inquiry or request.

6
7 In no way has the Company's standard collection or disconnect policies and
8 practices changed between a transaction that is handled digitally or through a call.
9 Through its Digital Self-Service investments, DTE Electric is expanding the ways
10 that customers can interact with the Company to complete their collection
11 transaction and not limiting or prioritizing one channel over another. As more
12 features and functionality are added to the Digital Self-Service channel, customers
13 choose which channel best meets their needs. The Company's investments in
14 Digital Self-Service do not signal a focus on collections efficiency rather than
15 affordability and assistance. I specifically discuss in my revised direct testimony at
16 page MJH-22, lines 18 through 19 and lines 22 through 24, expanding the restore
17 electric service and payment extension eligibility to include more customers and
18 that the Company will be providing new online assistance tools that will guide
19 customers who are having difficulty paying their bill to the most appropriate
20 payment solutions and sources of energy assistance, as part of the 2024-2025
21 Collection digital improvements. See Exhibit A44, Schedule II1 in which I provide
22 more details regarding these digital improvements and their customer benefits. The
23 rapid growth in Collection digital engagement by customers is evidence that
24 customers see value in these technologies, and they meet their needs.

25

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1 **Q19. Does DAAO Witness Koepfel acknowledge value in DTE Electric's**
2 **investments in digital self-service? Do you agree with him that digital self-**
3 **service should be complementary to call support?**

4 A19. Yes, he does acknowledge such value. Witness Koepfel says in his direct testimony
5 at page 33, lines 2 through 3 that he thinks improving these [digital] systems is
6 beneficial to customers; however, he doubts they will generate the call volume
7 reductions the Company claims. Given that he expects affordability issues for
8 customers will increase, Witness Koepfel asserts that digital self-service should be
9 considered complementary to call support, at page 33, lines 4 through 8 of his direct
10 testimony. As expressed throughout my rebuttal testimony, the Company agrees
11 that digital self-service is complementary to the support provided by our Contact
12 Center. By 2027, even with our projected call volume reductions, we still expect to
13 handle 2.7 million calls annually, 945,000 or 35% of which will be Collection calls,
14 as shown in Exhibit A-24, Schedule N5, on page 1, line 3, column (e). Thus, the
15 Company is not planning to de-prioritize or no longer answer calls. Customers can
16 always choose to contact the Contact Center and speak to a CR if they are
17 uncomfortable using a digital solution, do not have access to a computer or the
18 internet, or simply prefer to talk to somebody to manage their Collection inquiry or
19 request. Regarding Witness Koepfel's doubts about the Company achieving its
20 projected call volume reductions, as I provided earlier, we are forecasting to reduce
21 133,000 Collection calls in 2024, which is higher than the projected reduction of
22 125,089 calls for 2024 and 2025 combined, as shown Exhibit A-24, Schedule N5,
23 page 2, line 10, columns (k) and (l).

24

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1 **Q20. What specific aspects of DAAO Witness Jacob's testimony, as it relates to**
2 **digital self-service and her recommended disallowance of the \$10.7 million in**
3 **Collection Digital Self-Service capital, are you rebutting?**

4 A20. The reasons for Witness Jacob's recommended disallowance of the \$10.7 million
5 in capital for Collection Digital Self-Service projects at page 21, lines 1 through 8,
6 page 23, lines 1 through 7, page 26, lines 1 through 8, and page 30, lines 1 through
7 22 of her direct testimony, are substantially the same as those of DAAO Witness
8 Koeppel. As such, my rebuttal to her arguments and assertions are the same as
9 those I provided to Witness Koeppel's arguments and assertions.

10

11 **Q21. What do you recommend to the Commission regarding DAAO Witnesses**
12 **Koeppel's and Jacob's recommended \$10.7 million in disallowance for**
13 **Collection Digital Self-Service projects?**

14 A21. I recommend the Commission to not adopt Witnesses Koeppel's and Jacob's
15 proposals to disallow \$10.7 million in capital for Collection Digital Self-Service
16 projects. The Company maintains that its Collection Digital Self-Service
17 investments are beneficial to customers, satisfy the needs of customers who choose
18 to engage in a digital self-service solution, and provide substantial savings that are
19 passed on to all customers through the rate-making process. All of these points are
20 discussed earlier in my rebuttal testimony, outlined in my revised direct testimony
21 at page MJH-20, line 17 through MJH-24 line 17, and supported by Exhibits A-24,
22 Schedule N5 and A-44 Schedule II1 in the instant case.

23

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- 1 **Q22. Has DAAO Witness Jacob sufficiently demonstrated that DTE’s digital self-**
2 **service tools, specifically the DTE Kiosks and automated messages, are**
3 **ineffective?**
- 4 A22. No, she has not. Witness Jacob uses DTE Kiosks and automated messages as
5 examples of the ineffectiveness of the Company’s digital self-service tools. Kiosks
6 are mostly considered a Payment Digital Tool due to the self-service capability it
7 provides for customers to make a payment as compared with payments that used to
8 be taken in person by “tellers” at DTE customer offices, which have since all
9 closed. DTE does not charge a fee for using its kiosk, contrary to Witness Jacob’s
10 direct testimony at page 19, lines 1 through 3. The kiosk upgrade referenced by
11 Witness Jacob at page 19, lines 3 through 6 of her direct testimony was categorized
12 as a Collection vs. Payment enhancement as it enabled the kiosks to accept
13 payments from customers who were disconnected due to non-payment and seeking
14 to restore service by displaying the full amount of payment due, including
15 reconnection fees and security deposits, if applicable. It is unclear how the fee-free
16 kiosks and a kiosk enhancement that allows customers who want to restore service
17 would cause low- or non-low-income customers more suffering from collections
18 and affordability issues or make it more difficult and burdensome to make a
19 payment as argued by Witness Jacob at page 19, lines 6 through 11 of her direct
20 testimony. The kiosk example does not illustrate how DTE Electric’s investments
21 in digital self-service have negatively affected low-income customers. I provide a
22 better representation of the types of Collection Digital Self-Service enhancements
23 that the Company is making, and the customer benefits they deliver in Exhibit A-
24 44, Schedule II and in my revised direct testimony at page MJH-22, lines 2 through
25 24.

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1 At page 19, line 18 through page 20, line 4 of her direct testimony, Witness Jacob
2 cites an instance when an automated message that notified newly verified low-
3 income customers to contact the Michigan Department of Health and Human
4 Services (MDHHS) for assistance in paying their DTE bill after state funding had
5 been exhausted on June 14, 2024, as an example of how the Company's digital self-
6 service tools provide outdated or inaccurate information. While the Company
7 strives to accurately communicate information to our customers and regrets any
8 confusion caused by its automated messages, this is a poor example for attempting
9 to show that the Company has fallen short with its digital investments. It was an
10 unanticipated, unique situation that state energy assistance funding had exhausted
11 3.5 months before the end of the fiscal year, and hence, reasonable that the
12 Company's automated messages may not have yet been updated.

13

14 Witness Jacob also raises some concerns related to the Company's Shut-off
15 Protection Plan (SPP) and Cash Only policies and processes in her direct testimony,
16 these topics will be addressed by Company Witness Jason Sparks on page 15 in his
17 rebuttal testimony.

18

19 **Q23. DAAO Witness Jacob says it is important for DTE to offer phone service to**
20 **customers undergoing affordability and collection issues at page 15, lines 1-6**
21 **of her direct testimony. Do you agree?**

22 A23. Yes, I agree, and want to reiterate that DTE's Contact Center will continue to
23 answer customer phone calls even as we enhance our digital self-service channels
24 and grow digital engagement. The Company expects to handle 2.7 million calls
25 overall, including 945,000 Collection calls, annually after reaching our 2027 call

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1 volume reduction goals, as shown in Exhibit A-24, Schedule N5, on page 1, line 3,
2 column (e). As previously emphasized, the Company is not planning to de-prioritize
3 or no longer answer customer calls. In response to Witness Jacob's concerns about
4 the lack of technological or digital literacy among many low-income or vulnerable
5 customers at page 17, line 22 through page 18, line 5 of her direct testimony,
6 customers can always choose at any time to contact the DTE Contact Center and
7 speak to a CR, if they are uncomfortable or unfamiliar with using a digital solution,
8 do not have access to a computer or the internet, or simply prefer to talk to
9 somebody to manage their Collection inquiry or request. We also anticipate that
10 customers will use the digital channels to self-serve simpler transactions and call
11 the Contact Center if they have more complex issues or requests to resolve. By
12 deflecting simple transaction calls to the self-serve channels, this will reduce wait
13 times, also a concern raised by Witness Jacob at page 15, lines 12 through 14 of her
14 direct testimony, and allow our CRs to focus on handling more complicated
15 customer requests.

16

17 **Responses to other Intervenor Questions, Concerns, and Assertions**

18 **Q24. Do you agree with DAAO Witness Koeppel that there has been a significant**
19 **increase in Customer IT capital expenditures being requested for recovery in**
20 **the instant case, for the projects sponsored in your revised direct testimony?**

21 A24. No, I do not. As discussed, my revised direct testimony on page MJH-2 line 22
22 through MJH-3, line 6 supports the reasonableness and prudence of Customer IT
23 capital expenditures in the amount of \$62.1 million for 2022 historical year ended
24 December 31, 2022, \$74.6 million in the projected bridge period (for the 24 months
25 ending December 31, 2024), and \$33.0 million for the projected test year period

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1 ending December 31, 2025, totaling \$169.7 million, as shown in Exhibit A-12,
2 Schedule B5.7.3, line 50 in the instant case. The \$181.1 million in IT capital
3 expenditures referenced by Witness Koeppel, at page 29, lines 4 through 8 of his
4 direct testimony, includes the \$169.7 million but erroneously includes \$11.4
5 million in historical IT capital expenditures, at page MJH-3, lines 7 through 11, of
6 which \$5.7 million is 2021 capital that was previously approved for recovery in
7 Case No. U-20836 and \$5.7 million in 2022-2023 capital already included in the
8 \$62.1 million and \$74.6 million above. Also, when comparing the amount of IT
9 capital expenditures between Case No. U-21297 and Case No. U-21534 for over-
10 lapping years (2022-2024) covered in both rate cases, Customer Service IT capital
11 expenditures requested for recovery have decreased by 12.6% from \$156.4 million
12 to \$136.7 million.

13

14 **Q25. MEIU Witness Barnes is inquiring about Commercial and Industrial TOU**
15 **Rate (C/I TOU) Implementation Timing and Tools, what would be the**
16 **Company's response to his request?**

17 A25. Witness Barnes in his direct testimony in Case No. U-21534 is recommending
18 approval of a C/I TOU rates with five proposed modifications, as discussed at page
19 4, line 19 through page 5, line 10 of his direct testimony. Included in his proposed
20 modifications (#4 and #5) were to add a requirement that any approved C/I TOU
21 rates be made available to customers within three months of the Commission's final
22 order in Case No. U-21534, and that at the same time DTE Electric should provide
23 a C/I TOU rate modeling tool that produces standardized reports for customers.
24 Witness Barnes also discusses the three-month timing of his recommendations for
25 making the C/I TOU rates available to customers at page 25, lines 4 through 10,

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1 and for making the rate comparison reports available at page 28, lines 13 through
2 22 of his direct testimony. Absent a final order in this case, it is premature to
3 commit to completing this work within three months of the final order. The actual
4 implementation timing will be wholly dependent on the specific details of the
5 approved rate, which will likely require significant modifications to our Customer
6 Relationship and Billing (CR&B) back-end and front-end systems, customer-facing
7 channels such as the web, system integrations, and reporting. As such, at this time
8 the Company would maintain that more than three months will be required to
9 responsibly complete all the necessary design, development and testing activities,
10 to ensure that customers are able to seamlessly transition to the new rate.

11

12 **Q26. Is MI-MAUI Witness Bunch correct that there are safety concerns for**
13 **customers making a payment at a DTE Kiosk?**

14 A26. No, he is not. The Company maintains that making a payment at a DTE Kiosk is a
15 safe, secure way for customers to make a cash or check payment. Witness Bunch
16 drew the wrong conclusion that there is a “real and not merely perceived” risk of
17 robbery for customers making a payment at a DTE Kiosk at page 12, lines 4 through
18 7 of his direct testimony based on his interpretation of the Company’s responses to
19 a discovery question in Exhibit MAU-9. As provided in our response, numerous
20 kiosks were damaged due to theft activity and taken out of service in 2023. To our
21 knowledge and based on what we can share of these theft investigations, the
22 instances of kiosk theft in 2023 were specifically directed at the kiosks themselves
23 and typically occurred when there was no one around to prevent the theft. Some
24 kiosks were also removed at some locations per the request of store owners as a
25 “precaution” and not because there had been an incident of robbery or theft at their

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1 location. The Company, of course, takes seriously the safety of our customers and
2 yet disagrees with Witness Bunch that we should warn customers who may be
3 making a cash payment at a kiosk about the theft activity at page 12, lines 13
4 through 16 of his direct testimony. Based on our understanding of the situations
5 surrounding these kiosk thefts, a warning to customers making a payment at a kiosk
6 was not warranted.

7

8 **Q27. MI-MAUI Witness Bunch also raises concerns about the geographic**
9 **distribution of the kiosks in his direct testimony at page 13, line 14 through**
10 **page 14, line 1, is there a reason why they are mostly located in Detroit and a**
11 **few nearby suburbs?**

12 A27. The DTE Kiosks were historically placed in or near customer offices where
13 customers made payments for their DTE bill in person, providing a self-service
14 option for customers who did not need to speak to someone about their payment.
15 These offices have since closed and the ability to make payments in the vicinity
16 was replaced by the kiosks. Geographic distribution, size of the community,
17 poverty rates, and the racial makeup of communities are not factors in determining
18 the location of kiosks.

19

20 **Response to MPSC Staff Recommendations for the EFC – Outage Status Project**

21 **Q28. MPSC Staff Witness Klocke requests that DTE Electric further describe and**
22 **provide continual updates to Staff in bi-annual updates and the Commission**
23 **in future rate cases regarding its ongoing efforts to improve the outage**
24 **customer experience. How do you respond?**

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1 A28. The Company appreciates Staff's agreement on the prudence, reasonableness, and
2 worthiness of the capital expenditures related to the EFC project expressed by
3 Witness Klocke at page 3, lines 21 through 23 of her direct testimony. We are also
4 aligned with Staff as it relates to the ongoing improvement of our outage processes,
5 digital channels, and related systems to provide customers with timely and accurate
6 communications related to customer power status, restoration estimates and other
7 status updates and notifications to keep our customers informed during an outage
8 event per Witness Klocke's testimony at page 4, lines 1 through 4. Accordingly,
9 the Company remains committed to achieving our long-term goals related to the
10 key EFC metrics of Power Restoration Accuracy and Timeliness, First Estimate
11 Accuracy, and Outage Notification Delivery, and as requested by Staff per Witness
12 Klocke's direct testimony at page 4, lines 9 through 12, and as described in my
13 revised direct testimony at page MJH-70, line 5 through MJH-73, line 16, and
14 supported by the Company's capital investments in the core and customer-facing
15 EFC systems.

16

17 In future rate cases, we will provide details about our progress, including our
18 continuous improvement efforts and learnings from executing on our customer
19 outage commitments during storms and any impacts due to major project
20 implementations (e.g., ADMS) per Staff's recommendation at page 5, lines 2
21 through 4 and lines 12 through 15 of Witness Klocke's direct testimony. Going
22 forward, the Company will also provide Staff status updates biannually as preferred
23 by Staff or at a cadence that allows us to provide meaningful status updates such as
24 after reaching key EFC milestones or after significant, catastrophic storms, to
25 assure Staff, and the Commission in future rate cases, that the EFC investments are

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1 steadily and reliably improving our customers' outage experience in accordance
2 with Staff's request at page 5, line 20 through page 6, line 2 of Witness Klocke's
3 direct testimony.

4

5 **Q29. Does this conclude your rebuttal testimony?**

6 A29. Yes, it does.

1 JUDGE WALLACE: Please proceed,
2 Mr. Janiszewski.

3 MR. JANISZEWSKI: I'm sorry, your Honor,
4 I have one clarification for the rebuttal exhibit that
5 Mr. Hatsios sponsored. It is Exhibit A-44 Schedule III1,
6 I had previously mentioned it as Schedule II2. So for
7 clarification, A-44 Schedule III1.

8 JUDGE WALLACE: All right. Thank you,
9 Mr. Janiszewski. All right. Please go ahead.

10 MR. JANISZEWSKI: Next, the Company moved
11 to bind into the record the Qualifications and Direct
12 Testimony of Shawn D. Burgdorf, consisting of a cover
13 sheet and 12 pages of questions and answers. The Company
14 also moves for the admission of the following three
15 direct exhibits sponsored by Mr. Burgdorf, marked as
16 Exhibit A-26 Schedule P1, Exhibit A-26 Schedule P2, and
17 Exhibit A-26 Schedule P3. The Company also moves to bind
18 INTO the record the Rebuttal Testimony of Shawn D.
19 Burgdorf, consisting of a cover sheet and six pages of
20 questions and answers. There were no exhibits to
21 Mr. Burgdorf's rebuttal testimony, and there are no
22 changes to his testimony or exhibits.

23 JUDGE WALLACE: Thank you,
24 Mr. Janiszewski. Is there any objection to binding in
25 the direct and rebuttal testimony of Mr. Burgdorf?

1 Hearing none, the testimony is bound in.

2 Is there any objection to admitting the
3 Company's exhibits at the close of cross, exhibits and
4 schedules sponsored by Mr. Burgdorf at the close of
5 cross? (No response.)

6 All right.

7 (Testimony bound in.)

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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
DIRECT TESTIMONY
OF
SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORE

Line
No.

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

2 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
3 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
4 (DTE Electric or Company) as the Manager of the Power Supply Strategy &
5 Modeling team within the Generation Optimization department.

6

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

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

9

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

11 A3. I received a Bachelor of Science Degree in Mechanical Engineering from
12 University of Michigan in 2005. I also received a Master of Business
13 Administration Degree from Eastern Michigan University in 2016.

14

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

16 A4. After receiving my Bachelor's degree from the University of Michigan in 2005, I
17 was employed by Consumers Energy Company (Consumers Energy). During my
18 initial employment at Consumers Energy, I worked in their production cost
19 modeling group where I supported the development of power supply forecasts using
20 the PROMOD® model as the basis. In 2009, I transferred positions into the
21 Transmission and Regulatory Strategies Department. In this role, I was responsible
22 for monitoring and analyzing filings by the Midcontinent Independent System
23 Operator, Inc. (MISO) at the Federal Energy Regulatory Commission (FERC). I
24 was also responsible for forecasting future transmission and certain energy market-

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1 related costs in Power Supply Cost Recovery (PSCR) proceedings before the
2 Michigan Public Service Commission (Commission or MPSC).

3
4 In 2012, I began my employment at DTE Electric within the Generation
5 Optimization Department. In 2015, I was promoted to a Supervisor position and
6 subsequently in October 2018, I was promoted to my current Manager position
7 within Generation Optimization.

8

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

11 A5. Yes. I have attended Utility Rate School and the Advanced Regulatory Studies
12 Program, both hosted by the National Association of Regulatory Utility
13 Commissioners (NARUC) and The Institute of Public Utilities Michigan State
14 University.

15

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

17 A6. My current responsibilities include acquisition of wholesale electric power supply
18 to reliably and economically serve the energy requirements of the Company's
19 customers including: optimization of the Company's generation assets, including
20 renewable energy facilities, within the wholesale power market; management of
21 emission allowance procurement; management of resource adequacy processes;
22 modeling the DTE Electric generation fleet; optimizing financial transmission
23 rights; and review and advocacy of Company recommendations regarding proposed
24 MISO rules, regulations, and business practices.

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- 1 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
2 **Commission (MPSC or Commission)?**
- 3 A7. Yes. I have sponsored testimony in the following MPSC cases:
- 4 U-16149 Consumers Energy's 2010-2011 Gas Cost Recovery (GCR) Plan
5 U-16485 Consumers Energy's 2011-2012 GCR Plan
6 U-16924 Consumers Energy's 2012-2013 GCR Plan
7 U-16890 Consumers Energy's 2012 PSCR Plan
8 U-17097-R DTE Electric's 2013 PSCR Reconciliation
9 U-17319-R DTE Electric's 2014 PSCR Reconciliation
10 U-17632 DTE Electric's 2013 Renewable Energy Plan Reconciliation
11 U-17680 DTE Electric's 2015 PSCR Plan
12 U-17793 DTE Electric's 2015 Amended Renewable Energy Plan
13 U-17804 DTE Electric's 2014 Renewable Energy Plan Reconciliation
14 U-17920 DTE Electric's 2016 PSCR Plan
15 U-17680-R DTE Electric's 2015 PSCR Reconciliation
16 U-18111 DTE Electric's 2016 Amended Renewable Energy Plan
17 U-18082 DTE Electric's 2015 Renewable Energy Plan Reconciliation
18 U-18143 DTE Electric's 2017 PSCR Plan
19 U-17920-R DTE Electric's 2016 PSCR Reconciliation
20 U-20069 DTE Electric's 2017 PSCR Reconciliation
21 U-20221 DTE Electric's 2019 PSCR Plan
22 U-20471 DTE Electric's 2019 Integrated Resource Plan (IRP)
23 U-20561 DTE Electric's 2019 Main Rate Case
24 U-20528 DTE Electric's 2020 PSCR Reconciliation
25 U-18091 DTE Electric's 2021 PURPA Avoided Cost

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1	U-20836	DTE Electric's 2022 Main Rate Case
2	U-21193	DTE Electric's 2022 IRP
3	U-21297	DTE Electric's 2023 Main Rate Case

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1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to calculate projected capacity related generation
4 costs that are part of the Company's power supply costs and establish the projected
5 wholesale market energy sales revenue net of fuel. To do this, I projected 2025
6 capacity-related generation costs used in the 2024 PSCR Plan (Case No. U-21425).
7 Also, from the 2024 PSCR Plan, I projected 2025 wholesale market revenues from
8 energy and ancillary services sales from the Company's capacity resources, and the
9 fuel cost associated with the Company's capacity resources to calculate projected
10 wholesale market energy sales revenue net of fuel. This information is used by
11 Company Witness Maroun in his calculation of cost of service.

12

13 I also discuss removing the wording "making an emergency purchase" from tariff
14 rates D1.1, D1.8, D3.3 and D5.

15

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

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

18	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
19	A-26	P1	Projected 2025 PURPA Capacity-Related
20			Generation Cost
21	A-26	P2	Projected 2025 PA295/PA342 Capacity-Related
22			Generation Cost
23	A-26	P3	Projected 2025 Capacity-Related Generation Cost &
24			Energy Sales Revenue Net of Fuel Cost

25

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

2 A10. Yes, they were.

3

4 **Q11. Section 6w(3)(a) of Act 341 requires that for rate design purposes the capacity**
5 **charge include capacity-related generation costs in the Company's PSCR**
6 **mechanism. What are the capacity-related generation costs included in the**
7 **Company's PSCR mechanism?**

8 A11. The Company's PSCR mechanism includes capacity-related generation costs
9 associated with Public Utility Regulatory Policies Act of 1978 (PURPA) power
10 purchase agreements, PA295/PA342 Company-owned renewable energy systems,
11 PA295/PA342 renewable energy contracts, and capacity purchases.

12

13 **Q12. How did the Company project the 2025 capacity-related generation costs for**
14 **PURPA power purchase agreements as included in its PSCR plan filing in**
15 **Case No. U-21425?**

16 A12. Most of the Company's PURPA contracts have three rate components: fixed,
17 operation and maintenance (O&M), and variable. Two of the Company's PURPA
18 contracts only have a capacity component. The projections for the fixed, O&M,
19 and capacity components were included in the capacity-related generation costs.
20 The total projected 2025 PURPA capacity-related generation cost is \$8.9 million as
21 shown on Exhibit A-26, Schedule P1, line 12.

22

23 **Q13. What costs associated with PA295/PA342 Company-owned renewable energy**
24 **systems and power purchase agreements are included in the PSCR?**

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1 A13. The portion of the cost of PA295/PA342 Company-owned renewable energy
2 systems that is passed through the PSCR Transfer Price mechanism is the approved
3 Transfer Price Schedule or the levelized cost of energy for the renewable energy
4 systems. The portion of the cost of PA295/PA342 power purchase agreements (i.e.,
5 non-Company owned) that is passed through the PSCR mechanism is the lower of
6 the Transfer Price approved for the power purchase agreement and the contract
7 price of the agreement.

8

9 The Transfer Price is a proxy for the incremental non-renewable capacity and
10 energy expense that would be passed on to the customer if the renewable energy
11 resource was not developed. The relevant statute explains that when setting the
12 Transfer Price, the Commission shall consider factors including, but not limited to,
13 projected capacity, energy, maintenance, and operating costs, information filed
14 under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including,
15 but not limited to, locational marginal pricing.

16

17 **Q14. How did the Company project the 2025 capacity-related generation costs for**
18 **PA295/PA342 company-owned renewable energy systems and power purchase**
19 **agreements?**

20 A14. The capacity-related generation cost for PA295/PA342 Company-owned and non-
21 Company-owned renewable energy systems and power purchase agreements is the
22 approved Transfer Price fixed component for each specific renewable energy
23 system. The total projected 2025 PA295/PA342 capacity-related generation cost is
24 \$130.5 million as shown on Exhibit A-26, Schedule P2, line 39.

25

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1 **Q15. How did the Company project the 2025 cost of capacity purchases?**

2 A15. The Company included the net capacity purchase costs based on the 2024 PSCR
3 Plan (Case No. U-21425) forecasted expense for the calendar year 2025. The
4 expense includes the Company's net transactions within the MISO annual Planning
5 Resource Auctions (PRA) covering the 2025 calendar year¹. Consistent with the
6 amount filed in Case No. U-21425, the Company is projected to sell capacity in the
7 amount of \$(1.3) million as shown on Exhibit A-26, Schedule P3, line 6.

8

9 **Q16. How did the Company calculate the projected 2025 energy sales revenue net**
10 **of projected fuel costs per Section 6w(3)(b) of Act 341?**

11 A16. Section 6w(3)(b) of Act 341 requires that the revenue, net of projected fuel costs,
12 from energy market sales, off-system energy sales, ancillary services sales, and
13 energy sales under unit-specific bilateral contracts be subtracted from the
14 Company's capacity costs before calculating its capacity charge. I performed the
15 calculation using the forecasted assumptions from the Company's 2024 PSCR Plan,
16 Case No. U-21425. To calculate the energy sales revenue net of projected fuel costs,
17 first the projected wholesale energy revenue from the Company's generation
18 resources (including power purchase agreements) was determined (Exhibit A-26,
19 Schedule P3, line 11). Next, the projected wholesale revenue associated with
20 ancillary services provided by the Company's generation resources was determined
21 (Exhibit A-26, Schedule P3, line 14). Finally, all fuel expenses associated with the
22 wholesale energy and ancillary services were determined (Exhibit A-26, Schedule
23 P3, line 20) and subtracted from the projected wholesale revenues (Exhibit A-26,

¹ MISO annual resource adequacy auctions cover the Planning Year from June 1st – May 31st. The 2024/25 Planning Year auction covers January 1st – May 31st, 2025 and the 2025/26 Planning Year auction covers June 1st – December 31st, 2025.

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1 Schedule P3, line 15) resulting in the energy sales revenue net of projected fuel
2 costs (Exhibit A-26, Schedule P3, line 22).

3

4 **Q17. What is the projected revenue associated with wholesale energy sales from the**
5 **Company's generation resources in 2025?**

6 A17. The Company receives wholesale energy revenues from the MISO wholesale
7 energy market for the electricity produced by its generation assets. The wholesale
8 energy revenues forecasted for all Company assets (including PPAs) in the
9 Company's 2024 PSCR Plan (U-21425) was calculated to be \$2.180 billion shown
10 on Exhibit A-26, Schedule P3, line 11. This was done by summing the hourly
11 generation multiplied by the corresponding hourly market price.

12

13 **Q18. Is the Company projecting any off-system energy sales or sales under unit**
14 **specific bilateral contracts in 2025?**

15 A18. No. These values are shown as zero on Exhibit A-26, Schedule P3, line 12 and 13.

16

17 **Q19. What is the projected ancillary services revenue from the Company's**
18 **generation resources in 2025?**

19 A19. The Company receives wholesale revenue for providing the following ancillary
20 services: regulation reserves, spinning reserves, supplemental, and short-term
21 reserves (all settled via MISO's energy and ancillary services market). The
22 Company's 2024 PSCR Plan projected that Company's generation resources would
23 generate \$4.3 million of wholesale revenue associated with regulation, spinning,
24 and supplemental reserves. The projected wholesale ancillary services revenues
25 from the Company's generation resources in 2025 are shown on Exhibit A-26,

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1 Schedule P3, line 14. Schedule 2 Reactive Ancillary Services Revenue is no longer
2 included since FERC approved elimination of compensation for Schedule 2 in
3 2023.

4

5 **Q20. What is the total projected wholesale energy sales revenue including ancillary**
6 **services in 2025?**

7 A20. The total projected wholesale energy sales revenue including ancillary services in
8 2025 is \$2.184 billion as shown on Exhibit A-26, Schedule P3, line 15.

9

10 **Q21. What is the projected fuel cost required to generate the projected wholesale**
11 **energy and ancillary services sales from the Company's generation resources**
12 **in 2025?**

13 A21. The projected fuel cost required to make the energy and ancillary services market
14 sales is projected from the generation in the 2024 PSCR Plan and includes: fuel,
15 variable component of power purchase agreements, and the variable component of
16 renewables (based on removing the fixed component of the MPSC-approved
17 transfer prices from the overall transfer price). Total projected fuel costs for the
18 Company's generation fleet are \$1,201 million as shown on Exhibit A-26, Schedule
19 P3, line 20.

20

21 **Q22. How did you address the MISO market administrative costs associated with**
22 **Schedule 17 as well as chemical and emission expenses?**

23 A22. I removed the Schedule 17 costs from being included in the fuel costs in accordance
24 with the Commission Order in Case No. U-20836. However, I believe that these
25 costs should be included in fuel costs under Section 6w(3)(b) of Act 341, because

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1 they are directly attributable to “injections” of energy into MISO and must be
2 incurred to effectuate the generation sales. I also removed the chemical and
3 emission costs which amount to \$28.4 million in accordance with the Commission
4 Order in Case No. U-21297, while I disagree with this direction. Chemical and
5 emission costs are required to produce the energy from a significant amount of the
6 Company’s generation assets and the revenues associated with the energy sales
7 would not be possible without these expenses. To give the “benefit” of the energy
8 sales to customers being assessed a capacity charge per the State Reliability
9 Mechanism (SRM) without including all the attributable costs required to produce
10 the energy and make the sales is not fair to the Company’s PSCR customers who
11 end up paying those extra costs, thus subsidizing customers on the SRM Capacity
12 Charge. The SRM was put in place to ensure that all electric suppliers were
13 planning for reliable energy supply, and it also allows for electric choice customers
14 to obtain temporary capacity from the incumbent utility while continuing to receive
15 energy from their alternative electric supplier. This flexibility already allows
16 electric choice customers to have the benefit of short-term market trends without
17 committing to the long-term investments needed for reliability, it should not
18 inappropriately burden the Company’s full-time customers by providing additional
19 subsidies to electric choice customers.

20

21 **Q23. How does the Company intend to handle any reconciliation of previous year**
22 **variance of wholesale energy sales revenue net of fuel costs?**

23 A23. The Company currently has no electric choice customers being assessed a capacity
24 charge, thus no reconciliation with any customers has been previously done. The
25 Company files a reconciliation exhibit in the annual PSCR Reconciliation case that

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1 would be used for any reconciliation adjustment if a customer were to be charged
2 the SRM.

3

4 **Q24. What is the Company's projected wholesale energy sales revenue net of**
5 **projected fuel costs per Section 6w(3)(b) of Act 341 for 2025?**

6 A24. The total projected 2025 wholesale energy sales revenue of \$2.184 billion, net of
7 \$1.201 billion in fuel costs equates to \$0.983 billion wholesale energy sales revenue
8 net of fuel costs as shown on Exhibit A-26, Schedule P3, line 22. This amount was
9 provided to Company Witness Maroun to develop his capacity related cost of
10 service.

11

12 **Q25. Why are you proposing to remove "making an emergency purchase" from**
13 **rates D1.1, D1.8, D3.3, and D5?**

14 A25. This language is not needed as any emergency interruptions are covered under other
15 language within these rates, specifically, "maintaining system integrity" and "when
16 available system generation is insufficient to meet anticipated load." The Company
17 does not make any specific emergency purchases as energy transactions are handled
18 through MISO during emergency declarations.

19

20 **Q26. Does this complete your direct testimony?**

21 A26. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHAWN D. BURGDORF

Line
No.

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

3 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
4 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
5 as the Manager of the Power Supply Strategy & Modeling team within the
6 Generation Optimization department.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company?**

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. The purpose of my testimony is as follows:

15 **Section I: State Reliability Mechanism Capacity Charge**

16 1. To explain how Energy Michigan Witness Zakem's proposed exclusion of
17 Power Purchase Agreement (PPA) and Company Owned Renewable costs
18 from the "Fuel Costs" for the "energy revenue sales net of fuel cost
19 calculation" would not change the final State Reliability Mechanism (SRM)
20 capacity charge ultimately calculated on Revised Exhibit A-16. I will also
21 discuss the challenges to determine costs and reconcile seasonally as
22 proposed by Witness Zakem. Finally, I will address why using the MISO
23 Auction Clearing Price is not appropriate for use as the SRM capacity
24 charge.

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- 1 2. To address Michigan Public Service Commission (MPSC or Commission)
2 Staff (Staff) Witness Revere's alternative SRM capacity charge proposal.

3 **Section II: Energy Market Price for R10 Rate**

- 4 3. To address the use of Day-Ahead (DA) or Real-Time (RT) Locational
5 Marginal Price (LMP) to set the R10 tariff rate as proposed by Association
6 of Businesses Advocating Tariff Equity (ABATE) Witness Dauphinais.

7
8 **Q4. Are you sponsoring any exhibits in this proceeding?**

9 A4. No.

10

11 **Section I: State Reliability Mechanism Capacity Charge**

12 **Q5. Do you agree with Witness Zakem's determination (page 12, lines 11 - 23) that**
13 **removing the \$260.787 million of fuel cost associated with power purchase**
14 **agreements (PPAs) and Company Owned renewables will result in an SRM**
15 **capacity charge of \$159.21/MW-day?**

16 A5. No. The cost breakdown shown in Exhibit A-26, Schedules P1 and P2 utilize PPA
17 contract terms or Transfer Price Schedules to attribute \$260.787 million as "fuel-
18 related costs" to PPAs and Company Owned renewables. Witness Zakem only
19 removed the \$260.787 million value from fuel costs used to calculate the "energy
20 sales revenue net of fuel costs" in Exhibit A-26 and used in Revised Exhibit A-16,
21 Sched F1.5, page 1 of 6. If the \$260.787 million is not considered "fuel", then this
22 amount would be considered a capacity-related cost. The same \$260.787 million
23 amount shown on Revised Exhibit A-16, Sched F1.5, line 5, would also need to be
24 removed. Correcting for this oversight made by Witness Zakem in his Exhibit EM-
25 6, in his rebuttal, Witness Maroun provides Exhibit A-38 Schedule CC2 that

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1 removes the \$260.787 million on line 5, column (b) which shows the calculation
2 resulting in the original SRM capacity charge of \$217.30/MW-day. Thus, Witness
3 Zakem's recommended removal of the calculated PPA and Company Owned
4 renewable "fuel-related" costs from the "energy sales revenue net of fuel costs"
5 would have no impact on the \$217.30/MW-day SRM capacity charge.

6

7 **Q6. What are your thoughts on Witness Zakem's recommendation (page 14, lines**
8 **12 - 13) to "require that the SRM Capacity Charge also be determined by**
9 **season"?**

10 A6. Calculating rates for each season simply to change the allocation of costs between
11 capacity and energy will create unnecessary additional burden, and the Company
12 believes that an annual allocation is sufficient for the SRM. It will substantially
13 increase the time required to break out the costs by season as there is currently no
14 breakdown by season when projecting costs in the Company's Power Supply Cost
15 Recovery (PSCR) Plan. This creates an unnecessary burden as the annual rate
16 recovers the same costs as the rate would if computed seasonally. Additionally, all
17 load serving entities (LSEs) have to show capacity demonstrations for an annual
18 period (even if it broken down by season) and customers switching providers for
19 less than a year is unlikely. The other challenge is performing a reconciliation of
20 costs by season. This would require significant time to determine how to perform
21 such a reconciliation as it is currently performed on a calendar year basis within the
22 PSCR Reconciliation case. Even if it is determined that a seasonal reconciliation
23 could be performed, it would still require a substantial amount of time to develop
24 on a going-forward basis. As I previously mentioned, the annual rate combined

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1 with the reconciliation recovers the same costs as rates for all four seasons, thus the
2 extra effort to create seasonal rates would not be beneficial.

3

4 **Q7. Do you agree with Witness Zakem's recommendation that "A workable and**
5 **fair solution would be to set the SRM Capacity Charge at the MISO seasonal**
6 **Auction Clearing Price and apply that charge to the MW value of deficiency,"**
7 **(page 19, lines 18-19)?**

8 A7. No. Witness Zakem's proposal to tie the SRM capacity charge to the MISO
9 Auction Clearing Prices is short sighted as the MISO's Planning Resource Auctions
10 (PRAs) do not ensure long-term resource adequacy. In fact, a capacity shortage
11 situation could easily arise because MISO's PRA is for a term of only one Planning
12 Year and it is performed only two months prior to that Planning Year, whereas the
13 planning and construction of new generating capacity can take several years. When
14 LSEs properly plan for the long-term capacity needs of their customers, the PRA
15 works as a residual auction for the upcoming Planning Year by providing a means
16 to buy and sell small amounts of capacity needed due to normal variances in load
17 and generation. MCL 460.6w (PA 341) requires LSEs to demonstrate they have
18 sufficient resources to meet their resource adequacy needs on a four-year forward
19 basis and the MISO Auction Clearing Prices (ACPs) for the upcoming Planning
20 Year do not represent the cost to build new generation for a capacity deficiency.
21 "The Legislature, in its wisdom, crafted Section 6w to give the Commission a tool
22 for better ensuring the reliability of electric supply for Michigan's electric service
23 ratepayers over the long term." U-18248 Order, p. 61 (Nov 21, 2017). Witness
24 Zakem's proposal to use MISO's ACPs to set the SRM capacity charge would
25 effectively negate long-term resource planning and there would be no need for

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1 capacity demonstrations as LSEs would effectively be able to just use the 1-year
2 forward MISO PRA for all their needs. To me this outcome seems like the opposite
3 of what was intended with MCL 460.6w (PA 341).

4

5 **Q8. What are your thoughts on MPSC Staff Witness Revere’s “Alternative SRM**
6 **Calculation” discussion beginning on page 8, line 21 through page 12, line 11**
7 **of his testimony?**

8 A8. The Commission should not order Staff's proposed alternative SRM calculation due
9 to lack of detail in this case. The Company disagrees with Witness Revere's claim
10 that the proper cost of capacity is CONE, or the cost to build a combustion turbine.
11 The cost of the Company's capacity fleet is based on many diverse resources
12 required to maintain a reliable grid. Witness Revere claims his SRM calculation
13 method will avoid pitfalls yet does not show a sample calculation to prove how it
14 may fluctuate during high and low market prices. Given the lack of detail and room
15 for misinterpretation, Witness Revere's method should not be considered at this
16 time.

17

18 **Section II: Energy Market Price for R10 Tariff Rate**

19 **Q9. Do you agree with Witness Dauphinais’s recommendation that “the**
20 **Commission require DTE to modify its R10 tariff to allow all R10 customers**
21 **on an annual basis to choose between the applicable day-ahead LMP or the**
22 **applicable real-time LMP.” (page 18, lines 11-14)?**

23 A9. No. The Company does not support customers being able to choose between the
24 DA LMP and the RT LMP on any cadence. The Company submits and clears all
25 forecasted customer load (including R10 customers) into the day-ahead (DA)

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1 energy market. Any changes from that forecast are settled in the real-time (RT)
2 energy market at the RT LMP. During normal system conditions prices are very
3 similar in the DA and RT markets thus the R10 rate impact would be minimal. R10
4 load is an interruptible service and the penalties assessed by MISO are based on RT
5 LMPs which are typically much higher than DA LMPs during interruptions.
6 Allowing an R10 customer to see the DA market price (after their energy was
7 offered) and then determine how to adjust their RT load creates a mismatch to what
8 DTE submits in the DA market. The increase in RT costs due to deviations from
9 the DA offers would be paid for by other DTE customers. Another way to address
10 the issue of RT penalties from MISO would be to directly pass through the MISO
11 penalties associated with not interrupting and remove the \$50/kW penalty that is
12 currently in the R10 tariff. This would hold other customers harmless regardless of
13 the LMP rate in the R10 tariff. In addition to the “gaming” concern raised by
14 Witness Dauphinais, if customers switch regularly and are allowed to choose
15 between the two different LMPs this would create additional burdens and cost to
16 DTE Electric for tracking and billing.

17

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

19 A10. Yes it does.

1 JUDGE WALLACE: All right. Please go
2 ahead, Mr. Janiszewski.

3 MR. JANISZEWSKI: Thank you, your Honor.
4 The Company now moves to bind into the record the
5 Qualifications and Direct Testimony of Jason E. Sparks,
6 consisting of a cover sheet and 23 pages of questions and
7 answers. The Company also moves for the admission of the
8 two exhibits sponsored by Mr. Sparks, designated as
9 Exhibit A-13 Schedule C5.8, and Exhibit A-32 Schedule W1.
10 The Company also moves to bind into the record the
11 Rebuttal Testimony of Jason E. Sparks, consisting of a
12 cover sheet and 20 pages of questions and answers. The
13 Company also moves for the admission of the two rebuttal
14 exhibits sponsored by Mr. Sparks marked as Exhibit A-41
15 Schedule FF1, and Exhibit A-41 Schedule FF2, and there
16 are no changes to Mr. Sparks' testimony or exhibits.

17 JUDGE WALLACE: O.K. Is there any
18 objection to binding in the direct and rebuttal testimony
19 of Mr. Sparks?

20 Hearing none, the testimony is bound in.
21 Is there any objection to the admission of the exhibits
22 and associated schedules that were sponsored by
23 Mr. Sparks? (No response.)

24 - - -

25 (Testimony bound in.)

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

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
DIRECT TESTIMONY
OF
JASON E. SPARKS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JASON E. SPARKS

Line
No.

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

2 A1. My name is Jason E. Sparks (he/him/his). My business address is One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
4 Services, LLC.

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 graduated from Central Michigan University with a Bachelor of Science in
11 Business Administration and a Master of Business Administration Degree.

12

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

14 A4. I have worked at DTE Energy since 2006, in several positions of increasing
15 responsibility. From 2006 until 2013, I worked in the Controller's Organization
16 performing many diverse tasks including processing journal entries, consolidating
17 budgets, and providing operational support and compliance work. Since 2014, I
18 have worked in the Customer Service Organization; first as a manager (in Revenue
19 Management & Protection and then the Call Center), the Director of the Metering,
20 Billing, and Exceptions teams, and now as Director of Revenue Management and
21 Protection.

22

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

24 A5. As Director of Revenue Management and Protection (RM&P) group for DTE, I am
25 responsible for the overall direction, strategy, leadership and management

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1 collection, theft mitigation, and low-income programs for DTE. The RM&P group
2 is responsible for driving reduced uncollectible expense for DTE Electric and DTE
3 Gas as well as optimizing the Energy Assistance funding for low-income
4 customers. I am updated weekly on operational performance measures for all of
5 Customer Service and receive updates on financial performance and strategic plans
6 to improve all areas of the Customer Service Business.

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 cases:

11	U-17999	2016 DTE Gas General Rate Case
12	U-18014	2016 DTE Electric General Rate Case
13	U-20836	2022 DTE Electric General Rate Case
14	U-21297	2023 DTE Electric General Rate Case
15	U-21291	2024 DTE Gas General Rate Case

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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to:

- 4 • Explain the details of the Company's Energy assistance program
- 5 • Provide details of DTE's Low Income Self-sufficiency Plan (LSP)
- 6 • Provide details of DTE's Low-Income Assistance (LIA) credits
- 7 • Provide details on the Rate Schedule D1.6 rate provision change
- 8 • Provide details of DTE's Residential Income Assistance credits (RIA)
- 9 • Provide details of DTE's Payment Stability Plan (PSP) pilot
- 10 • Explain and support the \$50.9 million of projected uncollectible expense

11

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

13 A8. Yes. I am sponsoring the following exhibits:

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-13	C5.8	Projected Operation and Maintenance
16			Expenses Uncollectible Accounts
17	A-32	W1	Assistance Disconnect Rates

18

19 **Q9. Were these exhibits prepared by you or under your direction?**

20 A9. Yes, they were.

21

22 **Energy Assistance Programs**

23 **Q10. What energy assistance programs does the Company provide to its**
24 **customers?**

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1 A10. The Company provides energy assistance programs to both low-income and
2 non-low-income customers. The Company's energy assistance programs
3 include the Affordable Payment Plan (APP), which is known as the Low-
4 Income Self Sufficiency Program (LSP), and Residential Income
5 Assistance and Low-Income Assistance (RIA and LIA) credits. For non-
6 low-income customers, we provide energy assistance through a 25% match
7 of the Low-Income Home Energy Assistance Program (LIHEAP) Direct
8 Support program administered by the Michigan Department of Health and
9 Human Services (MDHHS) as well as Energy Waste Reduction (EWR)
10 services. Additionally, to further understand and meet the energy
11 affordability needs of our customers, we have implemented the Payment
12 Stability Plan (PSP) pilot approved in the Case No. U-20929 Order. I will
13 discuss all these programs in further detail in my testimony.

14

15 **Q11. What is the goal of the Company's energy assistance programs?**

16 A11. DTE Electric's energy assistance programs are structured with several primary goals
17 in mind:

18 **Sustained Energy Access:** The foremost objective is to ensure that customers,
19 particularly those with low incomes, have continued access to essential energy
20 services. These programs strive to prevent service interruptions and help customers
21 maintain a reliable source of energy for their households.

22 **Arrears Reduction:** The programs aim to alleviate customer arrears, which are
23 outstanding or overdue payments. By providing assistance to reduce accumulated
24 arrears, the burden on customers is eased, enabling them to manage their financial

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1 obligations more effectively.

2 **Payment Habit Encouragement:** DTE Electric's initiatives are designed to

3 promote responsible payment behaviors among participants. By offering

4 affordable monthly payments, these programs assist customers in establishing

5 a habit of regular bill payments.

6 **Consumption Reduction:** Another goal is to encourage customers to reduce

7 excessive energy consumption. Through education, incentives, and awareness

8 campaigns, the programs seek to curb wasteful energy practices, thereby benefiting

9 both customers and the environment.

10 **Short-Term Assistance:** While aiming for long-term sustainability, the programs

11 provide short-term assistance to help customers bridge the gap during periods of

12 financial strain. This assistance is intended to alleviate immediate challenges while

13 participants work toward self-sufficiency.

14 **Empowerment and Self-Sufficiency:** Ultimately, the programs aspire to empower

15 customers to become self-sufficient in managing their energy-saving practices. By

16 guiding participants toward better financial management and energy-saving

17 practices, the programs equip customers with the tools to afford the actual costs of

18 their energy consumption over time.

19 **Community Collaboration:** Collaboration with external entities, such as social

20 service agencies, government departments, and community organizations, is a

21 central aspect of these programs. This collaboration helps identify eligible

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1 participants, tailor assistance strategies, and generate effective solutions for present
2 and future energy challenges.

3 In summary, DTE Electric's energy assistance programs encompass a
4 comprehensive range of goals that collectively aim to ensure energy access,
5 alleviate energy burden, reduce arrears, and create pathways to energy assistance
6 that address crisis situations.

7

8 **Q12. What efforts has DTE Electric taken to maximize the benefits available to the**
9 **greatest number of its most vulnerable low-income customers?**

10 A12. The Company understands the challenges facing our low-income customers and
11 utilizes both external and internal resources to proactively identify and assist our
12 customers. Collaborating with social service agencies, government departments
13 like MDHHS, and community action groups is a strategic priority. These
14 partnerships provide valuable insights, resources, and expertise to better understand
15 the needs of low-income customers and design effective assistance programs.
16 Internal engagement focuses on continually improving how to engage and guide
17 our customers toward energy assistance options. This integrated approach can yield
18 sustainable solutions that benefit both the Company and its low-income customers.
19 While these strategies have the potential to make a positive impact not only on our
20 customers, but the broader community, they also can address changing
21 circumstances and evolving customer needs.

22

23 **Q13. What external collaborations are working to maximize benefits to low-income**
24 **customers?**

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1 A13. As mentioned above the Company collaborates with community action agencies
2 such as The Heat And Warmth Fund (THAW), Salvation Army, and United Way
3 and Community Economic Development Association of Michigan (CEDAM). The
4 Company also collaborates with the Energy Affordability and Accessibility
5 Collaborative (EAAC) subcommittee recommendations for streamlined energy
6 assistance applications and a standardized partnership with the state to leverage
7 data-sharing similar to the process utilized with MDHHS during the LIHEAP direct
8 support initiative. This allows DTE Energy and other utilities to identify income
9 qualified households and proactively provide pathways to energy assistance like
10 RIA credits and EWR services more efficiently.

11

12 **Q14. What actions is the Company taking to ensure that customers are aware of**
13 **available energy assistance?**

14 A14. The Company continues to inform customers of available energy assistance through
15 the standard channels such as 2-1-1, a free service that connects Michigan residents
16 with help and answers from health and human services agencies and resources in
17 their communities, and information provided through digital channels. In addition,
18 the following accessibility strategies have been implemented:

- 19 • Outbound call campaign to SPP customers for SER application assistance
- 20 • Automated letter campaign to motivate potential energy assistance eligible
- 21 customers to seek assistance early to avoid service interruption
- 22 • Email blasts to past recipients of SER funding
- 23 • Email outreach to customers receiving Notice of Intent (NOI) letters

24 Accessibility strategies focus on expanding the SER application process and
25 leveraging community partnerships, involving virtual webinars to raise awareness

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1 and virtual Customer Assistance Days (CAD)s to promote MEAP and other energy
2 assistance. Understanding the possible mail delivery delays through the United
3 States Postal Service (USPS), the proactive NOI email initiative will notify
4 customers more quickly and will help to prevent service interruption.

5

6 **Low Income Self-Sufficiency Program (LSP)**

7 **Q15. What does the Company consider its key Affordable Payment Plan?**

8 A15. LSP is the Company's APP. It is a 2-year payment plan for vulnerable families at
9 or below 150% Federal Poverty Level (FPL) to make affordable monthly payments
10 based on income and energy usage. The Company partners with social service
11 agencies and the State of Michigan to further support and promote LSP. The LSP
12 program provides comprehensive support that helps eligible customers afford their
13 utility service. The comprehensive support includes wrap-around services from
14 agency partners in the form of education, energy efficiency, and other self-
15 sufficiency services over the course of their participation. While participating in
16 the plan, customers have the benefit of sustained energy. The plan eliminates any
17 future late payment charges, and past due energy charges are frozen while the
18 customer receives a monthly arrears forgiveness credit. Additionally, a dedicated
19 team of customer advocates within the Company are ready to assist customers while
20 enrolled in LSP.

21

22 **Q16. How long has the Company offered LSP to its customers?**

23 A16. Public Act 615 of the Michigan Public Act of 2012 established the Michigan
24 Energy Assistance Act requiring the MDHHS to administer the Michigan Energy

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1 Assistance Program (MEAP). For just over a decade the MEAP funds have
2 supported LSP. In addition to DTE, CMS, UPPCO, and SEMCO offer APPs.
3

4 **Q17. Have there been recent changes to LSP?**

5 A17. Yes, in 2023, the MPSC took measures to align utilities on eligibility and the
6 administration of APPs. As a result, several changes were made to LSP. See the
7 table below.
8
9

Table 1

Affordable Payment Plan Alignment Update - Changes to LSP

Components	Existing LSP – Fixed Customer Payment	New LSP – Modified Budget Billing Plan
Plan Length	24 Months	24 Months
Federal Poverty Level (FPL) Tiers	• 20-75 % • 76-110% • 111-150%	• 1-19%¹ • 20-75 % • 76-110% • 111-150%
Consumption Cap	• \$1,600 for Electric Only • \$2,150 for Gas Only • \$3,750 for a Dual Commodity	No cap as the customers plan amount is reflective of their unique usage.
Arrears Forgiveness	• Arrears are frozen at the time of enrollment and paid off monthly. • \$3,000 arrears cap	• Upfront arrears forgiveness payment of up to \$600. • A 2nd Arrears payment of up to \$600 at 12 months. • A final arrears payment of \$1,800 at the completion of the plan. • No arrears cap.
Monthly Gap Payment	A credit is provided to offset the difference between the actual billed usage and the customer's plan amount.	• A flat monthly credit is provided to subsidize the customer's plan amount to make it more affordable than a traditional budget billing plan. • A reconciliation credit will be provided at the 12-month settlement to avoid additional customer burden.
Plan Calculation	• The customer's plan amount is based on the customer's FPL and usage but is not unique to the customer. • The customer's plan amount is set at enrollment and only changes if the customer moves.	• The customer's plan amount is based on their average monthly consumption and reduced by an agency credit chosen based on the customer's FPL. • The customer's plan amount is re-evaluated every 6 months and can change based on the customer's consumption behavior.

1. FPL Customers between 1-19% FPL requires MPSC approval in the existing LSP format.

10

11 **Q18. How does the Company measure success for the current LSP program?**

12 A18. In the current LSP program, a household is considered successful when completing
13 the fiscal year without being removed for non payment.
14

15 **Q19. Will the Company change how it measures success of the modified LSP?**

Line
No.

1 A19. Yes. The Affordable Payment Plan Alignment subcommittee is working towards
2 providing new metrics to define success of the modified LSP. This will include the
3 definition of graduation and plan success over multiple fiscal years.
4

5 **Q20. What are the Year Over Year (YOY) success metrics for LSP since its**
6 **implementation?**

7 A20. Table 2 depicts the metrics for LSP since its inception in 2013. This measure is
8 customers avoiding disconnect due to missed payments.
9

10 **Table 2 LSP Success Rate 2013-2022**

LSP Yr	2013	2014	2015	2016	2017	2018	2019*	2020**	2021	2022
Success Rate	80%	81%	92%	88%	91%	89%	67%	85%	82%	81%

11 *First year State Emergency Relief was required as part of the LSP enrollment eligibility

12 ** First year of 24 month LSP due to APP Alignment changes

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1 **Q21. How many households that graduated from LSP returned to the program?**

2 A21. Throughout the program an average of approximately 16% of graduates return to
3 the LSP program as shown in Table 3.

4

5

Table 3 LSP Graduate Metrics

LSP Yr	Enrolled	Grad	Grad Percentage	Number Returned	Return %	Eligible for Graduation
2015-16	35,089	4,474	13%	1,189	27%	35,089
2016-17	40,049	4,278	11%	1,315	31%	40,049
2017-18	34,344	1,881	5%	93	5%	34,344
2018-19*	36,109	4,877	14%	573	12%	36,109
2019-20**	16,306	-	0%	-	0%	N/A
2020-2021	23,511	1,756	67%	178	10%	2,642
2021-2022	26,097	5,631	74%	611	11%	7,578
2022-2023	23,750	3,174	62%	354	11%	5,079
*First year SER was required as part of the LSP enrollment eligibility						
**Excluded due to first year of moving from a 48 month to 24-month LSP payment plan due to APP Alignment changes						

6

7 **Q22. What ways are customers eligible for graduation from current LSP?**

8 A22. Prior to the 2019-20 fiscal year LSP graduates were selected based on their account
9 balance at the end of the fiscal year and not based on their time on the program. In
10 the current program format in addition to customers achieving a zero balance for
11 graduation status, customers are provided 24 months of eligibility on the program
12 and graduation can occur for those customers who complete the 24 months even
13 with a balance.

14

15 **Q23. Why is it important to provide pathways to self-sufficiency for households**
16 **such as those who have graduated from LSP?**

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1 A23. After discontinuing the support of LSP, customers often encounter difficulties in
2 maintaining consistent monthly payments, leading to potential crises. This
3 challenge is particularly pronounced for individuals on fixed incomes, such as
4 seniors, retirees, and minimum wage workers, who struggle to meet their financial
5 obligations. For instance, a single minimum wage earner in Michigan, earning
6 \$10.10 per hour in 2023, would have an Adjusted Gross Income of \$19,401 after
7 accounting for Social Security and Medicaid taxes.
8
9 Considering the 2023 Federal Poverty Level (FPL) for a single-person household
10 is \$13,590, the 150% of FPL threshold stands at \$20,385. However, according to
11 the Massachusetts Institute of Technology Living Wage Calculator, the living wage
12 for an individual in the Detroit – Warren – Dearborn area is \$33,705¹. This indicates
13 a significant gap between minimum wage earnings and the income required for a
14 basic standard of living.
15
16 Moreover, if we apply the Bureau of Labor Statistics' 2020 estimate that
17 approximately one percent of full-time workers nationwide earn federal minimum
18 wage or less to DTE's customer base, at least one percent of customers may lack
19 the income necessary to cover all living expenses in the area ². This includes not
20 only those below the poverty line but also individuals earning up to approximately
21 250% of the FPL.

¹ Living Wage Calculator - Living Wage Calculation for Detroit-Warren-Dearborn, MI (mit.edu) available at <https://livingwage.mit.edu/metros/19820> accessed on January 17, 2023.

² Characteristics of minimum wage workers, 2020 : BLS Reports: U.S. Bureau of Labor Statistics available at <https://www.bls.gov/opub/reports/minimum-wage/2020/home.htm> accessed on January 17, 2023.

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1 The economic improvements in Michigan from 2010 to 2019, as indicated by
2 reduced unemployment, GDP growth, and slight wage increases, did not alleviate
3 financial struggles for a significant portion of households. In 2019, 38% of
4 Michigan's households still faced challenges. While 13% were living below the
5 Federal Poverty Level, a larger segment—26%—comprised ALICE households:
6 Asset Limited, Income Constrained, Employed. These households earned above
7 150% of the FPL but fell short of meeting essential household needs.³

8

9 These circumstances underscore the importance of exploring payment options that
10 extend beyond the conventional 24 months and surpass the 150% FPL
11 requirements. Such solutions are crucial for customers facing long-term financial
12 constraints.

13

14 **Q24. What is the Payment Stability Plan (PSP) pilot?**

15 A24. The PSP pilot is a percentage of income-based program directed at low-income
16 customers at or below 200% FPL. PSP is a 2-year pilot that started in the first
17 quarter of 2022. The pilot focuses on the importance of affordable energy as it
18 relates to energy burdens for low-income customers. Customers who receive either
19 gas or electric utility service from DTE Gas or DTE Electric have a flat bill payment
20 equivalent to 6% of the household gross income. Customers who receive both gas
21 and electric utility service from the Companies have a flat bill payment equivalent
22 to 10% of the household gross income. PSP enrollees were also contacted to receive
23 EWR education services and provided partner agency information to receive wrap

³ ALICE In Michigan: A Financial Hardship Study, Live United 2021 Michigan Report, pg. 1, available at <https://www.unitedforalice.org/michigan>, accessed January 17, 2023.

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1 around services such as financial literacy, housing and food assistance, job and
2 education development, children and family services, and transportation.

3

4 **Q25. What are the early observations of the PSP pilot?**

5 A25. Participants in the PSP pilot exhibited a 21% enhancement in on-time and in-full
6 payments, resulting in an average reduction of arrears by 43%. Moreover, a
7 noteworthy improvement in service interruption was observed when compared to
8 eligible households not enrolled in PSP.

9

10 **Q26. What are the next steps for the PSP pilot?**

11 A26. The Company remains committed to conducting a thorough analysis of data, with
12 the intent of sharing valuable insights with key stakeholders to assess the long-term
13 viability of the pilot. The Commission's directive to the MPSC EAAC
14 subcommittees to delve into the effectiveness of offering Percentage of Income
15 Payment Plans (PIPP) to Michigan households is a central focus for 2024. This
16 underscores a proactive commitment to addressing energy affordability for
17 vulnerable households.

18

19 **Q27. Why is it important to expand energy assistance to households with FPL's**
20 **greater than 150%?**

21 A27. As stated earlier, the ALICE population, households above the 150% FPL still face
22 financial challenges and are vulnerable to energy insecurity. Offering assistance to
23 this group helps prevent them from falling into financial distress, reducing the risk
24 of falling into crisis resulting in service interruption.

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1 **Residential Income Assistance and Low-Income Assistance Credits**

2 **Q28. What other methods of assistance are there for low-income customers?**

3 A28. Another key program addressing energy sustainability for our low-income
4 customers is the RIA and LIA assistance credits.

5

6 **Q29. What are the current key features of the RIA credit?**

7 A29. The RIA credit offers low-income electric customers \$8.50 per month credit on
8 their bill. To be eligible, the total household income cannot exceed the 150% FPL,
9 as verified by an authorized State or Federal agency. The credit is renewed annually
10 based on the eligibility requirements. Customers may not receive both an electric
11 RIA and electric LIA credit at the same time.

12

13 **Q30. How can a customer become enrolled to receive the electric RIA credit?**

14 A30. Customers who receive energy assistance in the form of a Home Heating Credit
15 (HHC), State Emergency Relief (SER), or one time assistance are automatically
16 enrolled to receive the RIA credit.

17

18 **Q31. How is a customer who is not a recipient of the above-mentioned energy
19 assistance able to enroll to receive the RIA credit?**

20 A31. Households that do not receive energy assistance in the form of HHC, SER, or one
21 time assistance by an agency may provide documentation validating their eligibility
22 and be manually enrolled.

23

24 **Q32. How does DTE Electric reach out to households not automatically enrolled for
25 the RIA credit?**

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1 A32. The Company has several ways that it reaches customers who may have a need for
2 the assistance. The Company distributes the “Payment Assistance Programs”
3 brochure annually, as required by the Commission. This brochure includes several
4 options for energy assistance and payment plans. Additionally, the brochure is also
5 available on the Company’s website for quick access. Customer Resource Events
6 also assist customers by providing a variety of options to lower energy burden and
7 provide pathways to EWR resources to lower monthly payments. In addition to
8 these communication touch points, our call center analysts are trained to inquire
9 and guide our customers to the best options for them to sustain energy through our
10 Agent Assist Tool, which is highlighted later in my testimony.

11

12 **Q33. In 2023 how many DTE Electric customers received the RIA credit?**

13 A33. Over 160,000 unique electric customers received the RIA credit in 2023 with an
14 annual monthly average of 75,522.

15

Table 4 2020-2023 Electric RIA Customer Counts

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,841	31,153	42,712	36,033	34,226	37,229	38,366	40,914	40,240	42,742	42,660	51,284	39,867
2021	49,353	47,625	59,867	59,242	56,920	70,009	60,730	60,095	57,133	54,675	52,637	54,668	56,913
2022	55,273	52,472	77,861	64,098	71,279	76,710	70,158	80,906	75,554	77,992	76,119	83,522	71,829
2023	83,898	67,558	84,225	68,573	79,637	74,767	71,061	80,429	77,502	77,240	70,466	70,910	75,522

16

Note: Customer counts are billing period end of month snapshots and year end variances to Part III reporting due to timing.

17

18 **Q34. How many RIA customers is the Company including in its projected test year?**

19 A34. In the projected test year, the Company is forecasting the RIA credit enrollment
20 monthly average of 83,000 customers.

Line
No.

1 **Q35. What is the key feature of LIA Credit?**

2 A35. The LIA credit (contained in Rate Schedule D1.6) offers qualifying low-income
3 electric customers a \$40 per month credit on their bill.

4

5 **Q36. What currently makes a customer qualified to receive the LIA credit?**

6 A36. To qualify for this rate an electric customer must have a total household income at
7 or below 150% FPL.

8

9 **Q37. Can any qualifying low-income customer currently be eligible to receive the**
10 **LIA credit?**

11 A37. Yes, though the Company prioritizes customers who are enrolled in the Company's
12 APP or already receiving the RIA credit.

13

14 **Q38. How many DTE Electric customers are currently enrolled and receiving the**
15 **electric LIA credit?**

16 A38. Over 38,000 unique households receive the electric LIA credit with an annual
17 monthly average of 32,125.

18

19 **Table 5 2020-2022 Electric LIA Customer Counts**

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	25,038	20,297	24,597	22,928	23,337	26,073	26,551	26,296	26,268	26,431	23,998	28,748	25,047
2021	25,896	24,025	29,348	27,369	26,226	30,633	27,769	29,214	27,950	26,250	27,888	33,852	28,035
2022	33,841	28,554	36,381	31,150	32,757	34,291	30,513	33,697	31,136	31,126	29,700	32,852	32,167
2023	32,991	28,434	35,831	29,326	34,622	32,927	30,851	35,128	34,227	32,492	28,972	29,703	32,125

20

Note: Customer counts are billing period end of month snapshot and year end variances to Part III reporting fall within 5%.

Line
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1 **Q39. What is the enrollment process for the LIA credit?**

2 A39. There are several ways a customer may receive the LIA credit.

3 1. Customers who become enrolled in the LSP program are also enrolled to
4 receive the LIA credit.

5 2. Graduates of LSP may continue to receive the LIA credit if maintaining their
6 low-income eligibility status.

7 3. At the Company's discretion, customers receiving the RIA credit can transition
8 to LIA when there is availability.

9 Aligning the LIA credit with LSP helps our most vulnerable customers move
10 toward self-sufficiency. Though non-LSP customers may also receive the LIA
11 credit, experience has shown that applying the low-income credit first towards a
12 long-term program yields the highest self-sufficiency and assists in preventing
13 missed payments.

14

15 **Q40. What would be the impact if the LIA credit was applied randomly instead of**
16 **strategically paired with customers enrolled in the LSP program?**

17 A40. In previous case filings the Commission has agreed with the Company and
18 determined that random application of the LIA credit is not as effective as when
19 customers are partnered with the LSP Program. Random application results in
20 higher disconnect rates amongst those customers who do not have the additional
21 support of an affordable payment plan such as LSP. Overall, customers receiving
22 the LIA credit without the pairing of LSP have twice the disconnect rate as those
23 receiving both LIA and LSP. See Exhibit A-32 Schedule W1. Lines 2,5,7, and 8,
24 which depict disconnect rates for non-LSP households receiving some type of
25 assistance, such as Michigan Energy Assistance Payment (MEAP), HHC, and RIA.

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1 LSP households receiving LIA represent a significant decrease in the number of
2 disconnects.

3

4 **Q41. Is the Company proposing any changes to the LIA program?**

5 A41. Yes. As described in the testimony of Company Witness Willis, the Company is
6 proposing to eliminate Rate Schedule D1.6 and to expand the availability of the
7 credit to all base residential rate schedules. This change will have no substantive
8 impact on the credit and will bring it in line with how the electric RIA is managed.
9 In addition, the Company is proposing to increase the LIA credit from \$40 to \$50.

10

11 **Q42. Why is the Company proposing to increase the LIA credit from \$40 to \$50?**

12 A42. In its December 11, 2015, Order in Case No. U-17767, the Commission approved
13 the creation of Rate Schedule D1.6, which included the \$40 LIA credit. The LIA
14 credit has remained the same since its creation at \$40. At the time of
15 implementation, the LIA credit represented an approximate 43% credit to an
16 eligible low income customer's bill compared to what the bill would have been
17 without the credit. Based on the current Rate Schedule D1.6 rates approved by the
18 Commission in Case No. U-21297, the current \$40 LIA credit represents an
19 approximate 34% credit to a low income customer's bill. The proposal to raise the
20 credit to \$50 aims to align the financial support provided to low-income customers
21 receiving LIA with the originally approved credit offset as a percentage of their
22 bills. The adjustment seeks to ensure that the credit amount is more in line with the
23 intended assistance for customers facing financial challenges, providing a more
24 consistent and impactful measure of relief.

Line
No.

1 **Q43. What is LIHEAP Direct Support?**

2 A43. The LIHEAP Direct Support assists eligible low-income households with their
3 heating and cooling energy costs, bill payment assistance, energy crisis assistance,
4 weatherization, and energy-related home repairs. In 2023, in partnership with
5 MDHHS and as part of the Coronavirus Aid, Relief, and Economic Security
6 (CARES) Act, the Company used match-funding to reduce the arrears in the
7 amount of \$1.9 million for over 3,500 low- and moderate-income households. The
8 total LIHEAP Direct Support program supported over 18,000 households and
9 provided over \$9 million in energy assistance. This collaboration required swift
10 action in defining and identifying eligible customers as well as a team effort in the
11 coordination of communication and system enhancements.

12

13 **Uncollectible Expense**

14 **Q44. What is Uncollectible Expense?**

15 A44. Uncollectible expense is the income statement impact of recognizing a reserve for
16 the portion of accounts receivable that is considered uncollectible.

17

18 **Q45. How is uncollectible expense determined?**

19 A45. Uncollectible expense is determined by a review of individual arrearage accounts
20 for the Company, recorded separately based on actual uncollectible performance
21 and as a reserve against accounts receivables.

22

23 **Q46. How does DTE Electric determine the accounts receivable (AR) reserve for**
24 **uncollectible accounts?**

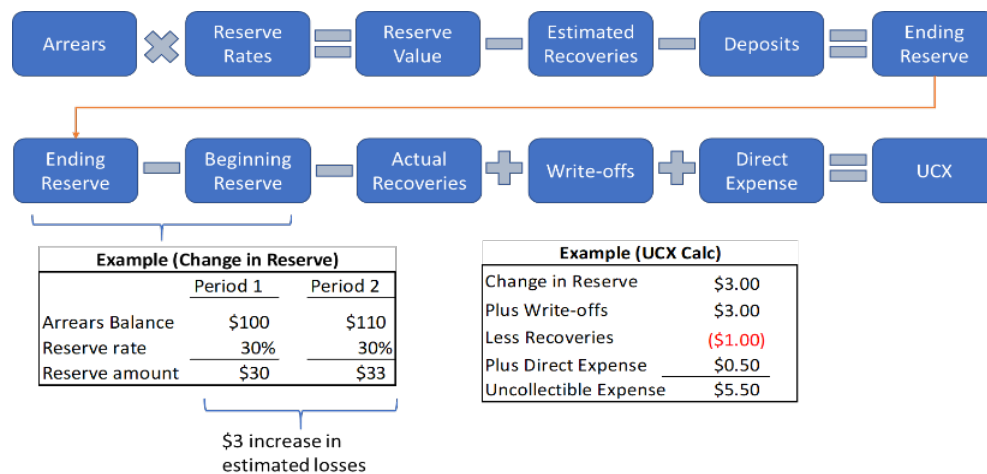
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- 1 A46. DTE Electric uses a balance sheet method. The AR reserve is calculated by
2 applying reserve factors to aged receivables. Customer accounts receivable are
3 classified in 30-day increments (arrears buckets) and a reserve factor is applied to
4 each 30-day increment. The sum of these reserve values represents the total AR
5 reserve. The Uncollectible Expense Calculation is shown in Figure 1.

6

7

Figure 1 Uncollectible Expense Calculation



8

- 9 The reserve factors are recalculated monthly using a rolling average of the ratio of
10 historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.).
11 A 12-month rolling average is utilized for residential and small commercial
12 accounts and a 60-month rolling average is utilized for large commercial and
13 industrial accounts.

14

15 **Q47. How does the Company account for uncollectible expense?**

- 16 A47. Uncollectible expense is recorded in the income statement to reflect the change in
17 the AR reserve. In any given month, this expense is calculated as the

Line
No.

1 increase/decrease in the AR reserve, plus accounts that were written-off during the
2 month, minus accounts that were recovered (on previously written off accounts)
3 during the month, plus write-offs of customer credits applied that are not expected
4 to be reimbursed to DTE Electric by agencies through the Low-Income Self -
5 Sufficiency Plan (LSP). Figure 1 is an illustration of the uncollectible expense
6 calculation process.

7

8 **Q48. What are the Company's write-off procedures?**

9 A48. Routine customer accounts are generally written off once they age to 150 days past
10 the final bill due date, which is issued after service is disconnected. Often,
11 however, there are circumstances that warrant keeping the account on the books
12 until a resolution is obtained – for example, customers with payment arrangements,
13 disputes, etc. Once an account is written off, any payments received on that account
14 are recognized as a recovery. The write-off period of 150 days past the final billing
15 is generally defined as the latest of either the last effective closed agreement date
16 or the last bill due date.

17

18 **Q49. How is uncollectible expense projected in this case?**

19 A49. To be consistent with prior rate making approvals, in this case the Company is
20 utilizing a historical three-year average of actual net write-offs plus direct expense
21 for 2020-2022 and adjusted for revenue growth, resulting in a \$50.9 million of
22 uncollectible expense. This amount is calculated on Exhibit A-13, Schedule C5.8
23 and shown on line 1, column (g) of that same exhibit.

Line
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1 **Q50. Is this the same methodology the Company used in its last rate case, Case No.**
2 **U-21297?**

3 A50. No. In this case, the Company is adopting the historical 3-year average of net write-
4 offs, similar to Staff's methodology from Case No. U-21297. In that case, the
5 Commission adopted and approved Staff's methodology, which is the same
6 methodology the Company is using in this case.

7

8 **Q51. In accordance with the Case No. U-21297 Order, is the Company providing a**
9 **report to the Commission Staff on any debt sale within the past 5 years?**

10 A51. The Company is not providing a report as it has not conducted any debt sales within
11 the past 5 years.

12

13 **Q52. Does the Company plan to complete a debt sale in the project test year?**

14 A52. No, the Company does not anticipate any debt sale in the projected test year.

15

16 **Q53. Does this complete your direct testimony?**

17 A53. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

JASON E. SPARKS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JASON E. SPARKS

Line
No.

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

3 A1. My name is Jason E. Sparks (he/him/his). My business address is One Energy
 4 Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
 5 Services, LLC.

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my testimony is to rebut the arguments made by:

- 14 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 15 Witness Rueckert on the \$9.8 million downward adjustment of uncollectible
- 16 expense
- 17 • Soulardarity and We Want Green, Too (collectively DAAO) Witness
- 18 Kinkhabwala's representation of the MPSC website disconnect chart
- 19 • Staff Witness Braunschweig's
 - 20 ○ argument against increasing low-income assistance (LIA) credit
 - 21 from \$40 to \$50
 - 22 ○ proposal to change tariff language of LIA credit
 - 23 ○ disallowance of 2023 residential income assistance (RIA) credit
 - 24 counts for the purpose of recovery

Line
No.

- 1 • Michigan Environmental Council and Natural Resource Defense Council,
2 (NRDC-MEC) Witness Colton's recommendations for the Company's low-
3 income programs
 - 4 ○ Method of recovery for LIA credits
 - 5 ○ RIA and LIA credit changes
 - 6 ○ LSP program changes
- 7 • DAAO Witness Schott's
 - 8 ○ representation of LIA and LSP enrollment methods
 - 9 ○ representation of Company's relationship with MDHHS and
10 community action agencies
- 11 • DAAO Witness Jacob's statements on Low-Income programs and claims
12 that the Company's Shut-Off Protection Plan (SPP) is in violation of the
13 Billing Practice Rules
- 14 • Ecology Center, the Environmental Law & Policy Center, the Union of
15 Concerned Scientists, and Vote Solar (Collectively CEO) Witness
16 Kenworthy's position that energy assistance programs should utilize the
17 MiEJScreen tool.
- 18 • Michigan Municipal Association for Utility Issues (MAUI) Witness
19 Bunch's position on the Company's cash only policy

20

21 The absence of a discussion of other matters in my rebuttal testimony should not
22 be taken as an indication that I agree with other aspects of any Staff or intervenor
23 testimony.

24

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

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No.

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

2	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
3	A-41	FF1	Staff UCX Calculation
4	A-41	FF2	AGDE-1.27b Discovery Response

5 **Q5. Were these exhibits prepared by you or under your direction?**

6 A5. Yes, they were.

7

8 **Uncollectible Expense**

9 **Q6. What uncollectible calculation method is Staff Witness Rueckert proposing in**
10 **this case?**

11 A6. Staff Witness Rueckert is applying three key elements in their uncollectible
12 calculation. They include 1) an update to include 2023 actuals 2) the use of present
13 revenues instead of projected revenues, and 3) the removal of full PSCR costs.

14

15 **Q7. Does the Company agree with Staff Witness Rueckert's proposed disallowance**
16 **of \$9.8 million in uncollectible expense (page 5, line 5)?**

17 A7. No. Staff Witness Rueckert's uncollectible expense calculation uses existing
18 revenue instead of projected revenue, which will not result in a reasonable
19 calculation of uncollectible expense when new rates are implemented. In addition,
20 Staff Witness Rueckert's projected billed revenue does not include PSCR revenue,
21 which is not consistent with how the historical uncollectible expense as a percent
22 (%) of revenue is calculated.

23

24 **Q8. Do you agree with Witness Rueckert's use of existing base rates to calculate**
25 **uncollectible expense?**

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1 A8. No. On page 5 of revised direct testimony, lines 12-13 Witness Rueckert describes
2 that using proposed rates will result in an iterative calculation and then goes on to
3 propose current revenue be used instead. The Company disagrees with this
4 approach. It is unreasonable because if new rates are approved, uncollectible
5 expense will be impacted by these new rates, in addition to projected billing
6 determinants. Staff's calculation uses current rates to calculate uncollectible
7 expense. Staff claims use of future revenues at proposed rates creates an iterative
8 calculation for the cost of service study, but provides no evidence as to why that
9 would make its proposal to use existing rates a reasonable approach. The
10 Commission agreed with Staff in its Order in Case No. U-21297 stating "the
11 Commission agrees with the Staff that using present revenue, rather than projected
12 revenue, avoids the creation of an iterative calculation and 'encourages the
13 Company to continually improve efforts to reduce [uncollectible expense] below
14 the amount set in rates.'" However, DTE Electric maintains that using rates
15 currently in place and excluding PSCR revenue is unjust, as it does not provide
16 DTE Electric a reasonable chance to recover uncollectible costs that it will be
17 incurring. Unlike capital expenditures or operation and maintenance expense,
18 which DTE Electric has some degree of control over and may be able to change in
19 response to a Commission order, uncollectible expense is impacted by factors that
20 are outside of DTE Electric's control.

21

22 **Q9. What method are you proposing to Staff's uncollectible expense calculation?**

23 A9. Staff should adopt the methodology that uses the Commission-approved
24 methodology of a three-year average of net write-offs to revenues. This is supported
25 by the direct testimony of AG Witness Coppola on page 110, line 1-3, "the

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1 Commission has stated in several cases that the use of a three-year average ratio of
2 charge-offs to revenues applied to future revenue is the most appropriate way to
3 forecast uncollectible accounts expense”. Witness Coppola correctly includes the
4 projected revenue, including PSCR and only updated the 3-year average to include
5 2023. This calculation results in a downward adjustment of \$3.8 million to what
6 the Company initially proposed, bringing the Company’s uncollectible calculation
7 from \$50.8 million to \$47.0 million for the projected test year.

8

9 **Q10. What adjustments are you proposing to Staff’s uncollectible expense**
10 **calculation?**

11 A10. As seen in Exhibit A-41 FF1-1, the Company does not oppose Staff and the AG
12 including 2023 in the three-year average to determine Net Write-Offs to Revenue.
13 Billed Revenue (line 4) in the Net Write-Offs to Revenue calculations properly
14 include PSCR revenue. For consistency, PSCR revenue should also be included in
15 Projected Billed Revenue (line 7). The Company agrees with the Projected Billed
16 Revenue amount used by AG Witness Coppola in Exhibit AG-41, line 5 of
17 \$6,399,006. This amount includes PSCR and anticipated future revenues and is
18 consistent with DTE Electric’s projections shared in Discovery Response AGDE
19 1.27b. (Exhibit A-41 FF2). This change drives a \$6.0 million increase to Staff’s
20 uncollectible expense calculation, increasing the total from \$41.0 million to \$47.0
21 million, consistent with the AG’s recommendation.

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1 **Disconnects**

2 **Q11. Do you agree with DAAO Witness Kinkhabwala’s direct testimony on page**
3 **16, lines 8-9 that DTE’s bill affordability is causing non-pay disconnects to**
4 **increase?**

5 A11. No. Witness Kinkhabwala makes a generalized statement of affordability
6 disconnects based on an incorrect understanding of the data behind the chart
7 provided in their testimony.

8

9 **Q12. Does DAAO Witness Kinkhabwala on page 17, lines 3-7 correctly present the**
10 **“Customer Disconnections by Utility” disconnect chart on the Michigan**
11 **Public Service Commission Utility Customer Data Tool website?**

12 A12. No. As part of the Case No. U-20757 Order, utilities were required to provide
13 several data points including but not limited to disconnects due to nonpayment. The
14 disconnect data that DTE provides, is representative of total number of residential
15 premises that were disconnected from 11/1/2019 to the last day of the reporting
16 month that have not been restored as of any reporting month (for ease of reference
17 see Figure below). The data is cumulative and not the number of actual disconnects
18 for any given month.

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1

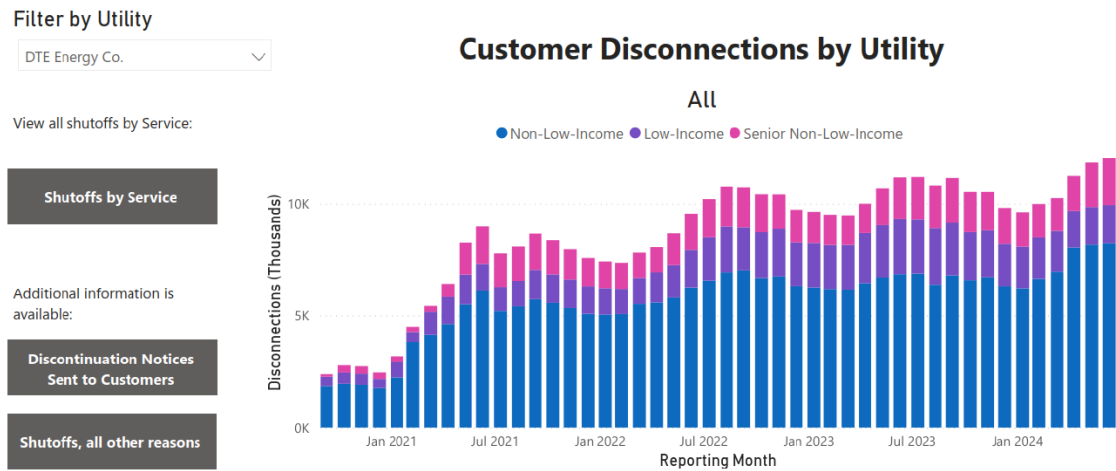


Figure 5: Screenshot from Michigan Public Service Commission Utility Customer Data Tool of historic shutoffs by DTE broken down by income category.

2 Low Income Programs

3 **Q13. Do you agree with Staff Witness Braunschweig recommendation to reject DTE**
4 **Electric's proposal to increase the Low Income Assistance (LIA) credit?**

5 A13. No. Witness Braunschweig recommends on page 5, line 19 through page 6, line 2
6 of their direct testimony that DTE Electric's proposal to increase the LIA credit
7 does not provide a comprehensive analysis and diverse collaborative input the
8 Commission is looking for to inform utility energy assistance change and therefore
9 should be rejected. However, the increase in the credit that is being requested is
10 only to keep it aligned with its original function of assistance. As stated in my direct
11 testimony, in 2015 when the LIA credit was implemented, it gave relief of 43% of
12 a low income customer's bill. The increase to \$50 aims to align the financial support
13 that is so needed and does not change the potential outcomes of the work or
14 potential outcomes of the Commission's Energy Affordability and Accessibility
15 Collaborative (EAAC) workgroups.

Line
No.

1 **Q14. Why does the Company disagree with Staff Witness Braunschweig's**
2 **recommendation to keep the LIA credit at its present \$40 amount?**

3 A14. Witness Braunschweig's direct testimony states that while they believe that
4 Michigan's most vulnerable customers would benefit from additional assistance, it
5 would be better to wait on the analysis being performed in the EAAC workgroups
6 on Percentage of Income Payment Plans (PIPP). Witness Braunschweig gives an
7 estimate target of Q1 of 2025 to propose a resolution to the PIPP analysis which
8 may include additional reform to the LIA credit. Even if a resolution is reached and
9 proposed by Q1 2025, it will take additional time for the Commission to rule and
10 provide the method of implementing such recommendations and further time to
11 retire and implement a new method of integrating the LIA credit funding. In the
12 meantime, there are low-income households struggling with bill affordability and
13 would greatly benefit from the proposed increase in the immediate future.

14

15 **Q15. Is the Company proposing to change the structure of the LIA credit?**

16 A15. No. DTE Electric is only asking to increase the amount of the credit. The eligibility
17 and structural methods of applying the credit will remain in place pending further
18 recommendations by the Commission.

19

20 **Q16. Do you agree with Staff Witness Braunschweig's method of excluding 2023**
21 **RIA enrollment counts when considering forecast projections?**

22 A16. No. Witness Braunschweig states (page 11, line 13-14) that on page 16 of my direct
23 testimony that the RIA counts, "were from billing period end of month snapshots
24 instead of monthly averages, as used in Part III Attachment 5(9)" and that the
25 reported numbers are different. First, to clarify, 2023 RIA counts were not included

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in Part III. Staff's concern about the accuracy of the 2023 RIA counts presented in my direct testimony, due to differences between the data in my direct testimony versus Part III Attachment 5(9), is unwarranted. For 2020 the overall annual average between the two sources remains quite close: 39,867 in my direct testimony versus 39,668 using Part III. In 2021 and 2022 the differences are immaterial: the largest monthly difference between my direct testimony and Part III was only eight customers, with the overall annual average difference being just three customers in 2022 and five customers in 2021. Therefore, excluding 2023 based on the differences between my direct testimony and historical Part III reporting is unwarranted, given the minimal discrepancies observed in the previous years. For ease of comparison, I have included the 2020-2023 data included in my direct testimony and the 2020-2022 data included in the Part III Attachment 5(9) below in Table 1 and Table 2:

Table 1 Electric RIA Customer Counts per Witness Sparks' Direct

Testimony

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,841	31,153	42,712	36,033	34,226	37,229	38,366	40,914	40,240	42,742	42,660	51,284	39,867
2021	49,353	47,625	59,867	59,242	56,920	70,009	60,730	60,095	57,133	54,675	52,637	54,668	56,913
2022	55,273	52,472	77,861	64,098	71,279	76,710	70,158	80,906	75,554	77,992	76,119	83,522	71,829
2023	83,898	67,558	84,225	68,573	79,637	74,767	71,061	80,429	77,502	77,240	70,466	70,910	75,522

Table 2 Electric RIA Customer Counts per Part III Attachment 5(9)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,632	30,546	42,921	35,150	34,222	36,974	38,501	40,711	40,019	42,557	42,233	51,546	39,668
2021	49,349	47,618	59,861	59,239	56,918	70,001	60,726	60,092	57,131	54,670	52,631	54,664	56,908
2022	55,269	52,469	77,853	64,094	71,276	76,709	70,158	80,901	75,554	77,992	76,119	83,522	71,826

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1 **Q17. Do you agree with Staff Witness Braunschweig that Low-Income Home**
2 **Energy Assistance Program (LIHEAP) funding should be the main**
3 **determinant of RIA enrollment fluctuation (pages 12-13)?**

4 A17. No. While it is true that Covid-related funding increased the number of households
5 applying for and receiving assistance, we cannot determine exactly how many new
6 households became energy assistance recipients without further analysis.
7 Additionally, much of the Covid-related assistance, such as Covid Emergency
8 Rental Assistance (CERA) and Michigan Homeowner Assistance Fund (MIHAF),
9 had broader eligibility criteria than the 150% Federal Poverty Level (FPL) required
10 by RIA. This means that even if a household received Covid-related assistance, it
11 didn't automatically qualify for the RIA credit. Additionally Witness
12 Braunschweig's testimony includes a table on page 13 which aligns LIHEAP
13 funding levels with RIA enrollments. However, the data is not supportive that
14 LIHEAP funding is a predictor of RIA enrollment trends. For example, LIHEAP
15 funding decreased from \$435.5 million to \$166.9 million in the next year, yet RIA
16 enrollments increased. Later, when LIHEAP funding rose to \$269.6 million, RIA
17 enrollments increased further, surpassing the levels seen when funding was at
18 \$435.5 million.

19 Furthermore, DTE Electric's systems automatically enroll customers who receive
20 not just LIHEAP funding, but also Home Heating Credit (HHC) or one-time
21 assistance. Although supplemental funding for LIHEAP has decreased since 2022,
22 HHC funding has increased and remains steady.

23

24 **Q18. Do you agree with Witness Braunschweig (page 14) that because the RIA**
25 **credit requires annual enrollment, that most customers will not re-enroll?**

Line
No.

1 A18. No. While it is true that some households will not reapply to receive the RIA credit,
2 the majority will remain recipients due to auto enrollment by other energy
3 assistance programs as well as self-attestation. Staff has even expressed the
4 importance of making sure that every eligible customer receives this credit. Even
5 with customers not renewing for the credit, it is unlikely that the forecast numbers
6 for the projected test year provided by Witness Braunschweig will revert to the
7 average monthly enrollments of 2021. Even though supplemental funding may be
8 eliminated, the number of households needing it will not.

9

10 **Q19. What is your position on Witness Braunschweig's (pages 14-15) use of the**
11 **ALJ's recommendation in the PFD of Consumer's Energy Case No. U-21389?**

12 A19. The recommendation presented is not relevant to DTE Electric's forecast for two
13 reasons. First, as pointed out in Witness Braunschweig's testimony, the ALJ on
14 page 379 referenced that Consumers presented, "a simple comparison of customer
15 counts for two months one year apart" and that, "the company's projection depends
16 on actual enrollment in March of 2023...". My direct testimony includes all 2023
17 enrollments, which clearly shows the increase in RIA enrollments. Additionally,
18 my forecast incorporated a two-year historical average of the monthly average of
19 enrollments and accounted for the 6% decline in 2023 accounts receiving energy
20 assistance, as detailed in Staff's Exhibit S-17.0 page 1. Second, also on page 379
21 the PFD states, "the PFD agrees with Staff that without a tracker or deferred
22 accounting, over-projection of RIA credits would result in Consumers retaining any
23 overcollection." However, DTE Electric has a tracker in place to correct any over
24 or under projection of enrollments. I would also like to note that Witness

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1 Braunschweig's testimony on page 15, line 12, which references the PFD,
2 inadvertently referred to "DTE" while the actual PFD refers to "Consumers".
3

4 **Q20. What method of LIA Cost Recovery does NRDC-MEC Witness Colton**
5 **recommend?**

6 A20. Witness Colton proposes the Company reconcile actual LIA costs to projected costs
7 on an annual basis where the under-recovered or over-recovered would be tracked
8 and filed as a regulatory asset in future regulatory filings. Witness Colton also
9 proposes that the costs should include incremental and net costs including
10 quantifying the cost benefit of things like impact to uncollectibles, arrears balances,
11 and operational impacts providing the LIA credit to customer's bills.
12

13 **Q21. What is the Company's current method of recovery for LIA expense?**

14 A21. As originally authorized in Case No. U-20561, the Company currently has a
15 mechanism in place to book a regulatory asset for any LIA credits issued above a
16 base amount. Case No. U-20836 clarified that any underspent amounts are netted
17 against (reduce) the regulatory asset. Case No. U-21297 approved the base amount
18 at 32,000 customers with an LIA credit of \$40.
19

20 **Q22. Does the Company agree with NRDC-MEC Witness Colton's proposal to**
21 **include additional cost benefit to uncollectibles when determining the LIA**
22 **expense?**

23 A22. No. The Company's forecasted LIA expense for the projected test year is grounded
24 in historical actuals. These historical figures already account for the benefits of the

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1 LIA credits. Therefore, additional analysis of their impact on uncollectibles is
2 unnecessary.

3

4 **Q23. Do you agree with NRDC-MEC Witness Colton’s recommendation on page 25**
5 **to increase RIA eligibility to 250% FPL?**

6 A23. While the Company acknowledges the necessity for energy assistance for
7 households exceeding 150% of the FPL, DTE Electric is bound by the billing
8 practice rules (460.11(2) and 460.10t(6)(b)). According to these rules, an “eligible
9 low-income customer” is defined as a customer whose household income does not
10 surpass 150% of the poverty level, as determined by the United States Department
11 of Health and Human Services.

12

13 **Q24. Are there any additional recommendations on pages 25-37 for the RIA and**
14 **LIA credit made by NRDC-MEC Witness Colton that you do not support?**

15 A24. Witness Colton has proposed several recommendations, including the application
16 of RIA and LIA credits to non-energy fees or services, arrears, and a tiered approach
17 to credit application. While these suggestions are valuable, they would be more
18 appropriately addressed by the EAAC workgroups currently focused on reforming
19 the RIA and LIA credits. The Company will continue its active participation in
20 these workgroups to identify the most effective solutions for this funding.

21

22 **Q25. What is your response to NRDC-MEC Witness Colton’s recommendations on**
23 **page 49 for modifying the Low-Income Self Sufficiency Plan (LSP), the**
24 **Company’s “arrearage forgiveness program”?**

Line
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1 A25. Under the guidance of the Michigan Department of Health and Human Services
2 (MDHHS) and the MPSC, utilities offer a Michigan Energy Assistance Program
3 (MEAP)-funded Affordable Payment Plan (APP). The Company's APP is known
4 as the Low-Income Self-Sufficiency Plan (LSP). Any structural changes to this
5 program would be addressed by the MEAP workgroup, which includes
6 representatives from Staff, utilities, and various agencies.

7

8 **Q26. Do you agree with DAAO Witness Jacob's position on pages 5-6, that DTE's**
9 **low-income programs are difficult to understand and navigate?**

10 A26. No. DTE utilizes numerous channels to provide information about low-income
11 programs, which are not limited to the Company's website or document portal.
12 DTE hosts face-to-face Community Resource Fairs and Community Pop-ups to
13 allow customers to interact with representatives to address any inquiries and obtain
14 hands-on assistance, in addition to communicating through email and printed
15 correspondence. In addition, DTE Electric employs a team of specialized
16 representatives who connect customers with access to both agency and government
17 programs. This team, known as the Energy Advocacy Group, also navigates
18 customers through applications for energy assistance crisis funding or State
19 Emergency Relief, administered by the MDHHS. Furthermore, DTE employs
20 additional measures to bridge a variety of gaps that our customer base encounters,
21 including those who face literacy challenges with digital technology. While
22 customers seeking energy assistance can work directly with MDHHS or a human
23 service agency, DTE Electric offers customers the opportunity to determine their
24 potential eligibility for energy assistance or for the Shut-Off Protection Program.
25 In those extenuating circumstances in which a customer is facing barriers such as

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1 technology, our specialized team is empowered to dispatch field representatives to
2 assist.

3

4 **Q27. DAAO Witness Jacob claims on page 8 of her direct testimony that there is**
5 **insufficient communication and coordination between DTE Energy and utility**
6 **assistance program providers. Is the communication and coordination**
7 **between DTE Energy and utility assistance programs providers sufficient?**

8 A27. Yes. DTE Energy collaborates extensively with utility assistance program
9 providers, as well as government entities, such as the MDHHS. Specifically, DTE
10 Energy meets individually with all human services agencies that supply MEAP
11 funds to DTE customers needing assistance. Standing meetings are held either bi-
12 weekly or weekly depending on the agency's need and preference, and those
13 meetings serve to provide status updates and address any specific administrative
14 issues. Similarly, DTE has an established meeting cadence with the MDHHS
15 LIHEAP leadership team and the Economic Stability Administration team. These
16 meetings keep communication channels open, addressing any policy or process
17 opportunities, which may include human performance errors such as payments
18 from MDHHS submitted to DTE incorrectly or system defects. Furthermore, DTE
19 is an active participant in the monthly MEAP workgroup meetings which are
20 comprised of the MPSC MEAP team members, MDHHS representatives, as well
21 as grantees and utility providers, and serve the purpose of collaborating on energy
22 assistance solutions.

23

24 **Q28. Does DAAO Witness Jacob correctly represent DTE's cash only policy?**

Line
No.

1 A28. No. Pages 7-8 of Witness Jacob's direct testimony incorrectly states that low
2 income households who miss a bill payment are required to use a DTE kiosk or an
3 authorized payment agent. Missed payments do not result in requirements to use a
4 kiosk or an authorized agent. Additionally, while there is a fee when using an
5 authorized payment agent, there is no fee required when using a DTE kiosk.

6

7 **Q29. Does DTE charge low income customers an inequitable higher rate for energy**
8 **service because of its cash only policy as described by Witness Jacob's**
9 **testimony on page 8?**

10 A29. No. All customers who have made payments with returned checks, credit/debit
11 cards are subject to the policy.

12

13 **Q30. Do you agree with Witness Jacob's position on page 7 on downpayments for**
14 **the Company's Shut Off Protection Plan (SPP)?**

15 A30. No. The Company asks for a 10% downpayment when enrolling customers on SPP
16 for the first time. If the customer defaults on that initial SPP and the Company offers
17 a subsequent SPP, the down payment requirement is higher to help reduce some of
18 the additional arrears the customer accumulated since the first default. The
19 Company believes this to be reasonable.

20

21 **Q31. Do you agree with Witness Jacob's position on page 10-12 that the Company**
22 **does not provide clear information as to how SPP operates?**

23 A31. No. DTE sends customers who have enrolled in SPP an enrollment confirmation
24 communication that very clearly indicates that "every three months, we review your
25 monthly plan amount to make sure it reflects your average energy usage. If the new

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1 average is 5% higher or lower than your current plan amount, we will adjust a
2 customer's monthly plan amount and they will see this adjustment in your next bill.
3 We will send you a notification after our review." So not only do we tell a customer
4 when they enroll but the Company closes the loop every quarter to let the customer
5 know if their bill is staying the same, is going up or going down. This approach
6 helps ensure that customers do not find themselves with a large balance due after
7 12 months because of higher usage than estimated. DTE does not assess a
8 "recalculation fee" as Witness Jacob states.

9

10 **Q32. Do you agree with DAAO Witness Schott's direct testimony on page 43**
11 **reporting of DTE's declining enrollment in affordable payment plans?**

12 A32. No. Witness Schott incorrectly categorizes DTE's SPP with the Company's
13 Affordable Payment Plan, LSP. Enrollments in LSP have remained steady (shown
14 in direct testimony Table 3 LSP Graduate Metrics JES-11).

15

16 **Q33. What is your response to DAAO Witness Schott's position on pages 43 and 44**
17 **that your position as Director of Revenue Management and Protection**
18 **prohibits the Company's ability to address the needs of energy affordability?**

19 A33. While it is understandable to perceive a potential conflict of interest in the dual
20 responsibilities of the Director of Revenue Management and Protection, the role
21 actually serves a more balanced and comprehensive purpose. The position is
22 designed to address the diverse needs of the Company's customer base, which
23 includes both enforcing payment policies and providing support to those in
24 financial distress. The dual responsibilities of the position allow the Company to
25 address affordability challenges more comprehensively.

Line
No.

1 **Q34. Is DAAO Witness Schott's testimony on page 48 regarding amounts collected**
2 **for reconnect and late fees on residential customers, correct?**

3 A34. No. Witness Schott ignores that the data provided on reconnection and late fees are
4 assessments and not necessarily what was collected by the Company. This is noted
5 in Exhibits DAO-139 and DAO-140.

6
7 **Q35. Do you agree with CEO Witness Kenworthy's direct testimony on page 12 that**
8 **energy assistance programs should utilize the MiEJScreen tool?**

9 A35. No. The MiEJScreen would be better served by the agencies that work with
10 households in providing outreach and pathways of energy assistance. Energy
11 assistance is equitable in that any income qualified households can access such
12 assistance and is not limited by demographic or geographic categories. Moreover,
13 DTE does not control the distribution of energy assistance dollars such as LIHEAP,
14 SER, HHC or one-time assistance. Only the LIA and RIA rate base credits are
15 distributed by DTE.

16
17 **Q36. Do you agree with MAUI Witness Bunch's assertion that the Company's cash**
18 **only policy is in violation of the billing practice rules?**

19 A36. No, the language in Section C4.6 of the rate book is a longstanding provision and
20 does not conflict with the billing rules. Importantly, Part 5 of the billing rules, which
21 covers Billing and Payment Standards, does not specify the form that payments
22 must take. Therefore, DTE retains the authority to determine the types of payments
23 it accepts. Furthermore, the Commission approved DTE Electric's cash payment
24 requirement in its Order in general base rate Case No. U-17767.

Line
No.

1 **Q37. Do you agree with Witness Bunch's direct testimony on page 15 that the cash**
2 **only policy will drive an increase in uncollectibles?**

3 A37. No. The assertion made by Witness Bunch lacks analysis to support the claim that
4 the Company's cash-only policy is a significant factor contributing to
5 uncollectibles. Contrary to Witness Bunch's assertion, the Company's cash-only
6 policy serves as a proactive measure to curb the escalation of arrears resulting from
7 returned payments. When a customer incurs consecutive returned payments, they
8 not only face the original unpaid balance but also an additional month's bill, which
9 can accumulate until the point of disconnection. This sequence of events
10 contributes to an increase in uncollectibles.

11

12 **Q38. Do you agree with Witness Bunch's recommendation on page 12 to assess**
13 **deposits instead of requiring cash only payments for customers who**
14 **demonstrate the behavior of paying with returned checks or closed accounts?**

15 A38. No. The suggestion to impose a deposit requirement on customers prone to making
16 payments with bad checks or from closed accounts does not address the core issue.
17 Such a requirement does not guarantee the elimination of insufficient funds
18 scenarios, as it does not inherently change the method of payment—merely the
19 preliminary conditions of service.

20

21 **Q39. Do you agree with Witness Bunch's overview of the Company's cash only**
22 **policy he provides on pages 7-8 of his testimony?**

23 A39. No. In recognizing the diversity of customer circumstances, the Company carefully
24 considers those with current balances, inadvertent errors, and instances of identity
25 theft. To elucidate the cash-only restriction process:

Line
No.

- 1 • Second Chance Provision: Customers who are either not in arrears or have
- 2 arrears of \$100 or less at the time of payment will not activate the cash-only
- 3 restriction, thus receiving a second opportunity. This policy allows
- 4 customers sufficient time to rectify the issue of the returned payment and
- 5 maintain access to various payment methods.
- 6 • Automatic Payment Plan Consideration: Customers enrolled in the
- 7 automatic payment plan who inadvertently enter incorrect payment
- 8 information are permitted up to two returned payments before the cash-only
- 9 restriction is applied.

10 The Company is committed to continuous improvement and actively reviews both

11 internal feedback from the contact center and external customer complaints. This

12 ongoing evaluation process ensures that our policies remain effective and fair, and

13 we remain open to further refinements to effectively reduce the incidence of

14 uncollectibles.

15

16 **Q40. Does this conclude your rebuttal testimony?**

17 A40. Yes it does.

1 JUDGE WALLACE: All right. Please
2 continue, Mr. Janiszewski.

3 MR. JANISZEWSKI: Thank you, your Honor.
4 The Company moves to bind into the record the
5 Qualifications and Revised Direct Testimony of Dr. Bente
6 Villadsen, consisting of a cover sheet and 85 pages of
7 questions and answers. The Company also moves for the
8 admission of the following 20 direct exhibits sponsored
9 by Dr. Villadsen, marked as Exhibit A-14 Schedule D5,
10 Exhibit A-14 Schedule D5.1, Exhibit A-14 Schedule D5.2,
11 Exhibit A-14 Schedule D5.3, Exhibit A-14 Schedule D5.4,
12 Exhibit A-14 Schedule D5.5, Exhibit A-14 Schedule D5.6,
13 Exhibit A-14 Schedule D5.7, Exhibit A-14 Schedule D5.8,
14 Exhibit A-14 Schedule D5.9, Exhibit A-14 Schedule D5.10,
15 Exhibit A-14 Schedule D5.11, Exhibit A-14 Schedule D5.12,
16 Exhibit A-14 Schedule D5.13, Exhibit A-14 Schedule D5.14,
17 Exhibit A-14 Schedule D5.15, Exhibit A-14 Schedule D5.16,
18 Exhibit A-14 Schedule D5.17, Revised Exhibit A-14
19 Schedule D5.18, and Exhibit A-14 Schedule D5.19. Next,
20 the Company moves to bind into the record the Rebuttal
21 Testimony of Dr. Bente Villadsen, consisting of a cover
22 sheet and 53 pages of questions and answers. The Company
23 also moves for the admission of the following 12 rebuttal
24 exhibits sponsored by Dr. Villadsen, marked as Exhibit
25 A-39 Schedule DD1, Exhibit A-39 Schedule DD2, Exhibit
Penn Reporting, LLC - lori.penn@yahoo.com

1 A-39 Schedule DD3, Exhibit A-39 Schedule DD4, Exhibit
2 A-39 Schedule DD5, Exhibit A-39 Schedule DD6, Exhibit
3 A-39 Schedule DD7, Exhibit A-39 Schedule DD8, Exhibit
4 A-39 Schedule DD9, Exhibit A-39 Schedule DD10, Exhibit
5 A-39 Schedule DD11, and Exhibit A-39 Schedule DD12. And
6 there are no changes to Dr. Villadsen's testimony or
7 exhibits.

8 JUDGE WALLACE: Thank you,
9 Mr. Janiszewski. Is there any objection to binding in
10 the direct -- or the revised direct and rebuttal
11 testimony of Dr. Villadsen?

12 Hearing none, the testimony is bound in.

13 Is there any objection to the admission
14 of the schedules and exhibits sponsored by Dr. Villadsen
15 in A-14 and A-39?

16 All right. We will admit those once
17 everybody's in.

18 (Testimony bound in.)

19 - - -
20
21
22
23
24
25

**BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION**

DTE ELECTRIC COMPANY)
)
) **Case No. U-21534**
)
)

**REVISED DIRECT TESTIMONY
OF
DR. BENTE VILLADSEN**

**LIST OF TOPICS ADDRESSED:
COST OF COMMON EQUITY CAPITAL**

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**BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION**

DTE ELECTRIC COMPANY)
)
) **Case No. U-21534**
)
)

DIRECT TESTIMONY OF DR. BENTE VILLADSEN

1 I. INTRODUCTION AND PURPOSE

2 Q1. Please state your name, occupation, and business address for the record.

3 A1. My name is Bente Villadsen (she her hers). I am a Principal of The Brattle Group,
4 whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts,
5 02108.

6 Q2. Briefly describe your present responsibilities at The Brattle Group.

7 A2. As a Principal, it is my responsibility to research and direct research into the utility
8 industry as it pertains to cost of capital and related issues. It is also my responsibility
9 to consult on utility industry issues and testify on utility industry matters. Among my
10 other duties is the supervision and training of staff and ensuring that work products are
11 of high quality and accurate.

12 Q3. Briefly describe your education and professional qualifications.

13 A3. I have 24 years of experience working with regulated utilities on cost of capital and
14 related matters. My practice focuses on cost of capital, regulatory finance, and
15 accounting issues. I am the co-author of the text, “Risk and Return for Regulated
16 Industries”¹ and a frequent speaker on regulated finance at conferences and webinars.

1 Bente Villadsen, Michael J. Vilbert, Dan Harris, A. Lawrence Kolbe, “*Risk and Return for Regulated Industries*,” Academic Press, 2017.

1 I have testified or filed expert reports on cost of capital in Alaska, Arizona, California,
2 Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Ohio, Oregon, Virginia and
3 Washington, as well as before the Bonneville Power Administration, Federal Energy
4 Regulatory Commission, the Surface Transportation Board, the Alberta Utilities
5 Commission, the Ontario Energy Board, Quebec's Régie de l'Énergie and Barbados'
6 Fair Trading Commission. I have provided white papers on cost of capital to the British
7 Columbia Utilities Commission, the Canadian Transportation Agency as well as to
8 European and Australian regulators on cost of capital. I have testified or filed testimony
9 on regulatory accounting issues before the Federal Energy Regulatory Commission
10 ("FERC"), the Regulatory Commission of Alaska, the Michigan Public Service
11 Commission, the Texas Public Utility Commission as well as in international and U.S.
12 arbitrations and regularly provide advice to utilities on regulatory matters as well as
13 risk management.

14 I hold a Ph.D. from Yale University and as BS/MS from University of Aarhus,
15 Denmark. Appendix A contains more information on my professional qualifications as
16 well as a list of my prior testimonies and publications.

17 **Q4. What is the purpose of your testimony in this proceeding?**

18 A4. DTE Electric Company ("DTE Electric", the "Company", or "DTEE") has asked me
19 to estimate the cost of equity that the Michigan Public Service Commission (the
20 "Commission") should allow DTE Electric an opportunity to earn on the equity-
21 financed portion of its regulated utility rate base. My recommendation also considers
22 the business and financial risk of the Company relative to the proxy companies to arrive
23 at my recommendation for the allowed Return on Equity ("ROE").

1 **Q5. Are you sponsoring any exhibits?**

2 A5. Yes. I am sponsoring Exhibit A-14, Schedule D5.1 through Schedule D5.19, which
3 contains the details of my analysis and supporting tables. Specifically, I sponsor the
4 following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-14	D5	Cost of Common Equity
A-14	D5.1	Table of Contents
A-14	D5.2	Classification of Companies by Assets
A-14	D5.3	Market Value of the Sample
A-14	D5.4	Capital Structure Summary of the Electric Sample
A-14	D5.5	Estimated Growth Rates of the Electric Sample
A-14	D5.6	DCF Cost of Equity of the Electric Sample
A-14	D5.7	Overall After-Tax DCF Cost of Capital of the Electric Sample
A-14	D5.8	DCF Cost of Equity at DTE Electric's Proposed Capital Structure
A-14	D5.9	Risk-Free Rates
A-14	D5.10	Risk Positioning Cost of Equity of the Electric Sample
A-14	D5.11	Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample

A-14	D5.12	Risk Positioning Cost of Equity at DTE Electric's Proposed Capital Structure
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A-14	D5.14	Electric Sample Average Asset Beta Relevered at DTE Electric's Proposed Capital Structure
A-14	D5.15	Risk Positioning Cost of Equity using Hamada-Adjusted Betas
A-14	D5.16	Risk Premiums Determined by Relationship Between Authorized ROEs and Long-Term Treasury Bond Rates
A-14	D5.17	FERC Market Risk Premium
A-14	D5.18	Revised DTE Electric and Electric Sample's Generation and Capital Expenditures
A-14	D5.19	Available Regulatory Mechanisms

1 **Q6. Were these Exhibits and the accompanying schedules prepared by you or under**
2 **your supervision?**

3 A6. Yes, they were.

4 **II. SUMMARY OF CONCLUSIONS**

5 **Q7. Can you summarize your primary conclusions and opinions on the appropriate**
6 **allowed ROE and business risk characteristics for DTE Electric?**

7 A7. Based on my estimation of the cost of equity for a sample of integrated electric utilities
8 and my analysis of DTE Electric's business and financial risk relative to the electric

1 peer group, I find that that a comparable group of integrated electric utilities have a
 2 cost of equity in the range of 10.25 percent to 11.0 percent using data as of December
 3 31, 2023. Given DTE Electric's higher than average business risk, allowing DTE
 4 Electric an opportunity to earn a ROE of 10.5 percent is conservative on its requested
 5 equity percentage of 50 percent. My recommendation is based on the following key
 6 observations:

- 7 • The estimated range determined by each of the implemented models is as follows:

8 **Figure 1: Summary of Electric Estimates at 50% Equity**

	Electric Sample	
	Low	High
CAPM / ECAPM	10.8%	11.7%
DCF	9.4%	11.2%
Risk Premium	10.5%	10.5%

9

10 Based on these results, I find that the estimated cost of equity indicates a CAPM
 11 based ROE in the range 10.75 to 11.75 percent, a DCF-based ROE of 9.5 to 11.0
 12 percent,² and a risk premium ROE of 10.5 percent.³ Taking the average of the
 13 low and high results indicates a range of 10.2 percent to 11.1 percent and a
 14 midpoint of 10.65 percent.

15 Based on my analysis, I conclude as follows:

- 16 • DTE Electric has higher business risk than the comparable electric utilities
 17 because of (1) the lack of a revenue decoupling mechanism (2) the generation
 18 mix, which is relatively heavy into coal and nuclear, and (3) the higher than

² Looking to the single-stage DCF before any consideration of financial risk, I find an average of 10.5 percent and an average of 10.2 percent if the highest and lowest two observations are ignored.

³ I do not believe that the lowest DCF estimate is reasonable due to the plausible need for substantial growth in the electricity sector to move towards a low carbon environment. However, the range derived from the average of the DCF, CAPM/ECAPM and risk premium models is, in my opinion, reasonable.

1 average need for infrastructure investments.⁴ Hence the recommended ROE is
2 conservative and a modest move towards today's indicated cost of equity.

3 • Treasury bond yields have increased since DTE Electric's last rate case in U-
4 21297, so it is no surprise that the cost of equity is higher today than at the time
5 of the U-21297 filing (February 10, 2023).⁵

6 **Q8. How is the remainder of your testimony organized?**

7 A8. Section III formally defines the cost of capital and explains the techniques for
8 estimating it in the context of utility rate regulation. Section III.A discusses conditions
9 and trends in capital markets and their impact on the cost of capital. Specifically, I
10 focus on the development in interest rates and inflation as well as the Federal Reserve's
11 response to inflation pressures. Section V explains my analyses and presents the results.
12 Section VI discusses DTE Electric's business risk characteristics, unique risks facing
13 Michigan-based electric utilities, and other company-specific circumstances relevant
14 to my recommended allowed ROE. Finally, Section VII concludes with a summary of
15 my recommendations.

16 **III. COST OF CAPITAL PRINCIPLES AND APPROACH**

17 **A. RISK AND THE COST OF CAPITAL**

18 **Q9. How is the "cost of capital" defined?**

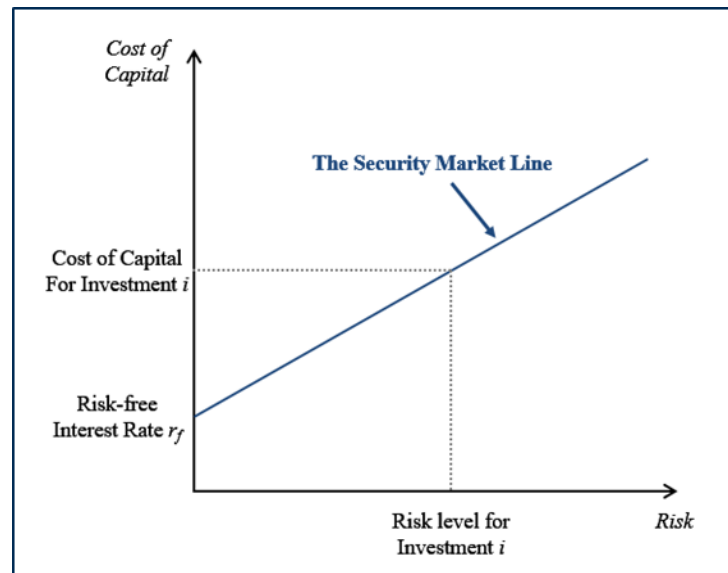
19 A9. The cost of capital is defined as the expected rate of return in capital markets on
20 investments of equivalent risk. Cost of capital theory illustrates the direct relationship
21 between risk and the expected rate of return – the higher the risk, the higher the cost of
22 capital required. This relationship is represented in the "security market risk-return
23 line" (or "Security Market Line" for short), which is depicted in Figure 2 below.

⁴ DTE Energy, "EEI Business Update," December 8, 2023, p. 18.

⁵ Data relied upon in the direct testimony in U-21297 would have been obtained somewhat earlier than February 10, 2023.

The cost of capital is comprised of the cost of debt and equity. Specifically, when estimating the cost of equity for a given asset or business, two categories of risk are important: (1) business risk and (2) financial risk. Business risk reflects the degree to which the cash flows generated by a business (and its assets) vary in response to moves in the broader market. Financial risk reflects the risk from the level of debt within a business.

Figure 2: The Security Market Line



Q10. What factors contribute to systematic risk for an equity investment?

A10. When estimating the cost of equity for a given asset or business venture, two categories of risk are important. The first is business risk, which is the degree to which the cash flows generated by the business (and its assets) vary in response to moves in the broader market. In context of the CAPM, business risk can be quantified in terms of an "assets beta" or "unlevered beta". For a company with an assets beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index.

1 The second category of risk relevant for an equity investment depends on how the
2 business enterprise is financed and is called financial risk. Section III below explains
3 how financial risk affects the systematic risk of equity.

4 **Q11. What are the guiding standards that define a just and reasonable allowed rate of**
5 **return on rate-regulated utility investments?**

6 A11. The seminal guidance on this topic was provided by the U.S. Supreme Court in the
7 *Hope* and *Bluefield* cases,⁶ which found that:

- 8 • The return to the equity owner should be commensurate with returns on
9 investments in other enterprises having corresponding risks;⁷
- 10 • The return should be reasonably sufficient to assure confidence in the
11 financial soundness of the utility; and
- 12 • The return should be adequate, under efficient and economical
13 management for the utility to maintain and support its credit and enable
14 it to raise the money necessary for the proper discharge of its public
15 duties.⁸

16 **Q12. How does the standard for just and reasonable rate of return relate to the cost of**
17 **capital?**

18 A12. The first component of the *Hope* and *Bluefield* standard, as articulated above, is directly
19 aligned with the financial concept of the opportunity cost of capital.⁹ The cost of capital
20 is the rate of return investors can expect to earn in capital markets on alternative
21 investments of equivalent risk.¹⁰

⁶ *Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia*, 262 U.S. 679 (1923) ("Bluefield"), and *Federal Power Com'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").

⁷ *Hope*, 320 U.S. at 603.

⁸ *Bluefield*, 262 U.S. at 680.

⁹ A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities was developed by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *Bell Journal of Economics & Management Science* 3:58-97 (1972).

¹⁰ The opportunity cost of capital is also referred to as simply the "cost of capital," and can be equivalently described in terms of the "required return" needed to attract investment in a particular security or other

1 By investing in a regulated utility asset, investors are tying up some capital in that
2 investment, thereby foregoing alternative investment opportunities. Hence, the
3 investors are incurring an “opportunity cost” equal to the returns available on those
4 alternative investments. The allowed return on equity needs to be at least as high as the
5 expected return offered by alternative investments of equivalent risk or investors will
6 choose these alternatives instead. If it is not, the utility’s ability to raise capital and
7 fund its operations will be negatively impacted. This is a fundamental concept in cost
8 of capital proceedings for regulated utilities such as DTE Electric.

9 **Q13. Please summarize how you considered risk when estimating the cost of capital.**

10 A13. To evaluate comparable business risk, I looked to a proxy group of regulated electric
11 and natural gas utilities.¹¹ The electric utilities I considered have a high proportion of
12 regulated assets and revenue, with the majority of the electric utilities having more than
13 80% of assets subject to regulation (predominantly by state commissions).
14 Additionally, all utilities I consider have a network of assets that are used to serve end
15 customers and they are capital intensive (meaning that each dollar in revenue requires
16 substantial investment in fixed assets).

17 **B. FINANCIAL RISK AND THE COST OF EQUITY**

18 **Q14. How does financial risk affect the estimation of a fair return on equity?**

19 A14. Regardless of the method used to calculate the cost of equity (versions of the CAPM,
20 DCF and risk premium), an issue in regulatory proceedings is how to apply data from
21 a benchmark set of comparable securities when estimating a fair return on equity for
22 the target/regulated company.¹² It may be tempting to simply estimate the cost of
23 equity capital for each of the proxy companies (using one of the above approaches) and

asset (i.e., the level of expected return at which investors will find that asset at least as attractive as an alternative investment).

¹¹ In past testimony on behalf of DTE Electric, I have included a gas LDC or water utility sample. Because of the substantial objection to the samples and because the samples have become smaller due to acquisitions or lack of data, I do not include such samples in this proceeding.

¹² This is also a common valuation problem in general business contexts.

1 average them. After all, the companies were chosen to be comparable in their business
2 risk characteristics, so why would an investor necessarily prefer equity in one to the
3 other (on average)?

4 The problem with this argument is that it ignores the fact that underlying asset risk (*i.e.*,
5 the risk inherent in the lines of business in which the firm invests its assets) for each
6 company is typically divided between debt and equity holders. The firm's debt and
7 equity are therefore financial derivatives of the underlying asset return, each offering a
8 differently structured claim on the cash flows generated by those assets. Even though
9 the risk of the underlying assets may be comparable, a different capital structure splits
10 that risk differently between debt and equity holders.

11 The relative structures of debt and equity claims are such that higher degrees of debt
12 financing increase the variability of returns on equity, *even when the variability of asset*
13 *returns remains constant*. Consequently, otherwise identical firms with different
14 capital structures will impose different levels of risk on their equity holders. Stated
15 differently, increased leverage adds financial risk to a company's equity.¹³

16 If the companies in a proxy group are truly comparable in terms of the systematic risks
17 of the underlying assets, then the **overall cost of capital of each company** should be
18 about the same across companies (except for sampling error), so long as they do not
19 use extreme leverage or no leverage. This is because a firm's asset value (and return)
20 is allocated between equity and debt holders. The expected return to the underlying
21 asset is therefore equal to the value weighted average of the expected returns to equity
22 and debt holders – which is the overall cost of capital or the expected return on the
23 assets of the firm as a whole.¹⁴

13 I refer to this effect in terms of financial risk because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the business risk associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

14 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility.

Q15. What is the theoretical basis supporting the notion that the overall cost of capital for each company should be about the same, regardless of capital structure?

A15. The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.¹⁵ Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (*i.e.*, the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,¹⁶ showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,¹⁷ the latter can still be shown to be constant across a broad range of capital structures.¹⁸

¹⁵ Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

¹⁶ Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

¹⁷ When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

¹⁸ This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

1 This reasoning suggests that one could compute the overall cost of capital for each of
2 the proxy companies and then average to produce an estimate of the overall cost of
3 capital associated with the underlying asset risk. Assuming that the overall cost of
4 capital is constant, one can then re-arrange the overall cost of capital formula to
5 estimate what the implied cost of equity is at the target company's capital structure on
6 a book value basis.¹⁹

7 **Q16. What other methods do you use to account for financial risk when determining**
8 **the cost of equity?**

9 A16. An alternative approach to account for the impact of financial risk is to examine the
10 impact of leverage on beta in the CAPM. The so-called Hamada method allows a
11 financial analyst to adjust for differences in financial risk by first translating the equity
12 beta obtained from market data into an asset beta (or a zero-debt beta) using the
13 comparable companies leverage and second relever (or translating) the asset beta for
14 the comparable companies into an equity beta for the target company using the
15 regulated entity's capital structure.²⁰

16 While there are several versions of the Hamada adjustment procedures as discussed in
17 Appendix B, the need to consider leverage is ubiquitous among finance practitioners
18 when using the CAPM to estimate discount rates.

19 **C. APPROACH TO ESTIMATING THE COST OF EQUITY**

20 **Q17. How do you approach your estimation of the cost of equity for DTE Electric?**

21 A17. To analyze the cost of equity for DTE Electric, I evaluate companies of comparable
22 business risk by choosing a proxy group of publicly traded regulated electric utilities.
23 I use three models to analyze the cost of equity for DTE Electric: (1) the Capital Asset
24 Pricing Model (CAPM) as well as an Empirical version thereof, the ECAPM, (2) the

19 Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

20 Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock",
The Journal of Finance, 27(2), 1971, pp. 435-452.

1 Discounted Cash Flow (DCF) models (single-stage and multi-stage), and (3) the Risk
2 Premium. Due to the continual changes in financial markets, I consider two
3 implementations of the CAPM / ECAPM – based on a historical and a forward-looking
4 MRP to determine a fair and reasonable ROE for DTE Electric. Section V further
5 explains my analyses and results.

6 **Q18. How does your approach and the models you employ compare to what the**
7 **Commission has considered in prior DTE Electric proceedings?**

8 A18. The Commission has in past decisions considered the DCF, CAPM, and Risk Premium
9 models, as do I. Additionally, the Commission has recognized that “atypical market
10 conditions” deserve consideration when setting the ROE.²¹ The Commission also stated
11 that it will “continue to monitor a variety of market factors in future applications,
12 including market reactions to recent events and measures of volatility and uncertainty,
13 as well as measures of investor confidence, and the utility’s risk profile.”²² It is also
14 evident that the Commission, like I, consider “the company’s unique circumstances and
15 characteristics ...” as well as “regional economic and company-specific risks.”²³
16 Lastly, the Commission’s recent decision in U-21297 acknowledged that “the cost of
17 equity in the utility sector has generally increased over the last year ...”²⁴
18 Consequently, I discuss the development in current capital market condition and the
19 impacts they have on determining DTE Electric’s cost of equity capital in Sections IV
20 and V below.

21 **IV. CAPITAL MARKET CONDITIONS**

22 **Q19. What do you cover in this section?**

21 Michigan Public Service Commission Order for Case No. U-18255, April 18, 2018, p. 33.

22 Michigan Public Service Commission Order for Case No. U-20561, May 8, 2020, pp. 177.

23 *Ibid.*, p. 176.

24 Michigan Public Service Commission, “Order in Case U-21297,” issued December 1, 2023 (“Order in U-21297”), p. 186.

1 A19. In this section, I address recent changes in capital market conditions and how these
2 factors affect the cost of equity and its estimation. Specifically, I address (i) interest
3 rate developments; (ii) investors perception of the market risk premium; (iii) inflation
4 expectations; (iv) volatility in the market as exemplified by the S&P 500; and (v)
5 developments in utility stock prices.²⁵

6 **Q20. Why do you discuss capital market conditions in a testimony aimed at determining**
7 **the DTE Electric's ROE?**

8 A20. Capital market conditions are important to cost of equity estimation methodologies and
9 can affect the inputs to the cost of equity models. Inputs to the DCF models are affected
10 by the economy in general as economic growth will affect growth rates and utility stock
11 prices. Consequently, the capital market developments affect the growth rates, the
12 dividend yield, and the assessment of estimates' reasonableness.

13 Similarly, the risk-free rate is an input to the risk premium model and CAPM, so that
14 recent and expected future developments in government bond yields are important to
15 assess the validity of any measure of the risk-free rate. The MRP is also an input to the
16 CAPM, so factors that affect the MRP (e.g., volatility and changes in investors' risk
17 perceptions) are vital for accurate determination of the ROE. Lastly, inflation has
18 recently been substantially above what the U.S. experienced over a very long period
19 and the inflation is expected to be above the Federal Reserve's two percent target for a
20 least the next two years.²⁶ Uncertainty about inflation expectations creates uncertainty
21 about the cost of capital as well as other aspects of utilities' costs.²⁷

22 **Q21. Can you provide a summary of recent events that have impacted capital market**
23 **conditions?**

25 In past testimony, I have discussed utility credit spreads. Utility credit spreads are currently only modestly elevated, so I do not attempt to account for this. However, inflation expectations remain a source of substantial concern and therefore merit consideration.

26 *Blue Chip Economic Indicators*, January 2024 expects 2024 inflation to be 2.6%, so while the inflation rate has modified, it remains- above the Federal Reserve's target rate of 2%.

27 Because the cost of capital is measured in nominal terms, inflation will influence the cost of capital.

1 A21. Since DTE Electric's last rate case was filed in February 2023 (Order dated December
2 1, 2023)²⁸ key measures of debt cost such as Treasury yields have increased and utility
3 bond yields and investors' perception of the risk premium they require to hold equity
4 rather than debt has remained relatively constant. At the same time, inflation remains
5 higher than in the recent past and inflation is expected to remain above the targeted 2
6 percent through at least 2025. In response, the Federal Reserve has increased the
7 Federal Funds rate 11 times since the beginning of 2022, 3 times since February 2023,
8 while holding the rate constant in recent months. The details are shown in Figure 3
9 below. Since the filing of DTE Electric's last rate case in February 2023, the Federal
10 Funds rate has increased by 75 basis points, while the yield on BBB rated utility bonds
11 increased during 2023 but as of now is comparable to that in late January / early
12 February 2023.²⁹ The Federal Reserve's monetary policy responses are intended to
13 achieve the Federal Reserve's goal of keeping "inflation at the rate of 2% over the
14 longer run."³⁰ The January 31, 2024 meeting confirmed the Federal Reserve's position
15 and kept the Federal Funds rate at 5.25 percent to 5.50 percent stating that "[t]he
16 Committee does not expect it will be appropriate to reduce the target range until it has
17 gained greater confidence that inflation is moving sustainable toward 2 percent."³¹
18 Most recently, the Bureau of Labor Statistics on February 13, 2024 announced that the
19 12-month inflation was 3.1 percent as of January 2024,³² above the Federal Reserve's
20 target rate of 2.0 percent.

28 Order in U-21297.

29 Comparing the yield on BBB rated utility bonds as of January 31, 2024 (5.68%) to the yield in January and February 2023; 5.31% and 5.78%, respectively. Source: Bloomberg data as of February 13, 2024.

30 See, for example, Federal Reserve, Press Release, July 26, 2023, <https://www.federalreserve.gov/monetarypolicy/files/monetary20230726a1.pdf>

31 Federal Reserve, Press Release January 31, 2024.

32 Bureau of Labor Statistics, News Release, "CPI for all items rose 0.3% in January; shelter up," February 13, 2024.

Figure 3: Developments in the Federal Funds Rate Since 2022

FOMC Meeting	Change (bps)	Federal Funds Rate
March 17, 2022	+25	0.25% - 0.50%
May 5, 2022	+50	0.75% - 1.00%
June 16, 2022	+75	1.50% - 1.75%
July 28, 2022	+75	2.25% - 2.50%
September 22, 2022	+75	3.00% - 3.25%
November 2, 2022	+75	3.75% - 4.00%
December 14, 2022	+50	4.25% - 4.50%
February 1, 2023	+25	4.50% - 4.75%
March 22, 2023	+25	4.75% - 5.00%
May 3, 2023	+25	5.00% - 5.25%
June 14, 2023	+0	5.00% - 5.25%
July 26, 2023	+25	5.25% - 5.50%
September 20, 2023	+0	5.25% - 5.50%
November 1, 2023	+0	5.25% - 5.50%
December 13, 2023	+0	5.25% - 5.50%
January 31, 2024	+0	5.25% - 5.50%

Lastly, the risk of the electric utility industry as measured by, for example, the systematic risk (beta) has remained constant.³³ Thus, capital markets' data as well as utility specific risk characteristics indicate that the cost of equity is higher today than in the recent past.

A. Interest Rates

Q22. How do interest rates affect the cost of equity?

A22. The current interest rate environment affects the cost of equity estimation in several ways. Most directly, the CAPM takes as one of its inputs a measure of the risk-free rate (see Figure 2). All else equal, the estimated cost of equity using the CAPM increases (decreases) by one percentage point when the risk-free rate increases (decreases) by

³³ In U-21297, I found an average beta of 0.88 for my electric sample (Villadsen Direct in U-21297, Figure 7, p. 33). I now find a slightly higher beta, 0.93 (Figure 7 below).

1 one percentage point. Therefore, to the extent that prevailing government yields are
2 affected by monetary policy, and rising geopolitical tensions, using current yields as
3 the risk-free rate would affect the CAPM estimate in a manner that may not reflect the
4 forward-looking cost of equity. Therefore, the allowed fair return on equity for DTE
5 Electric should reflect the future interest rate environment, specifically the environment
6 at the time the rates being set in this proceeding will be in effect.

7 **Q23. What are the relevant developments regarding interest rates?**

8 A23. Yields on 20-year U.S. Treasury Bonds were 3.95% at the time DTEE's filed its last
9 rate case in February 2023.³⁴ Since then the yield on 20-year Treasury bonds has
10 increased to approximately 4.32% at the end of 2023 for an increase of about 40 basis
11 point.³⁵ Looking forward, professional forecasters as well as government agencies
12 expect Treasury bond yields to remain relatively constant in the near-term and then
13 decrease slightly over the next couple of years. However, they expect the yields to
14 remain well above the low levels of the recent past. Blue Chip Economic Indicators
15 (BCEI) as of January 2024 forecast the yield on 10-year Treasury bonds at 3.9% for
16 2024 and 3.7% 2025 for an average of 3.8% over the next two years.³⁶ The 2024
17 forecast increased to 4.0% in February 2024.³⁷ The 2024 and 2025 BCEI forecasts are
18 40 to 60 basis points below the current 10-year Treasury bond yield (4.3%) indicating
19 interest rate forecasts are currently lagging actual interest rates. Similarly,
20 Congressional Budget Office's December 2023 economic forecasts expects the 2024

34 Exhibit D5.9.

35 Ibid.

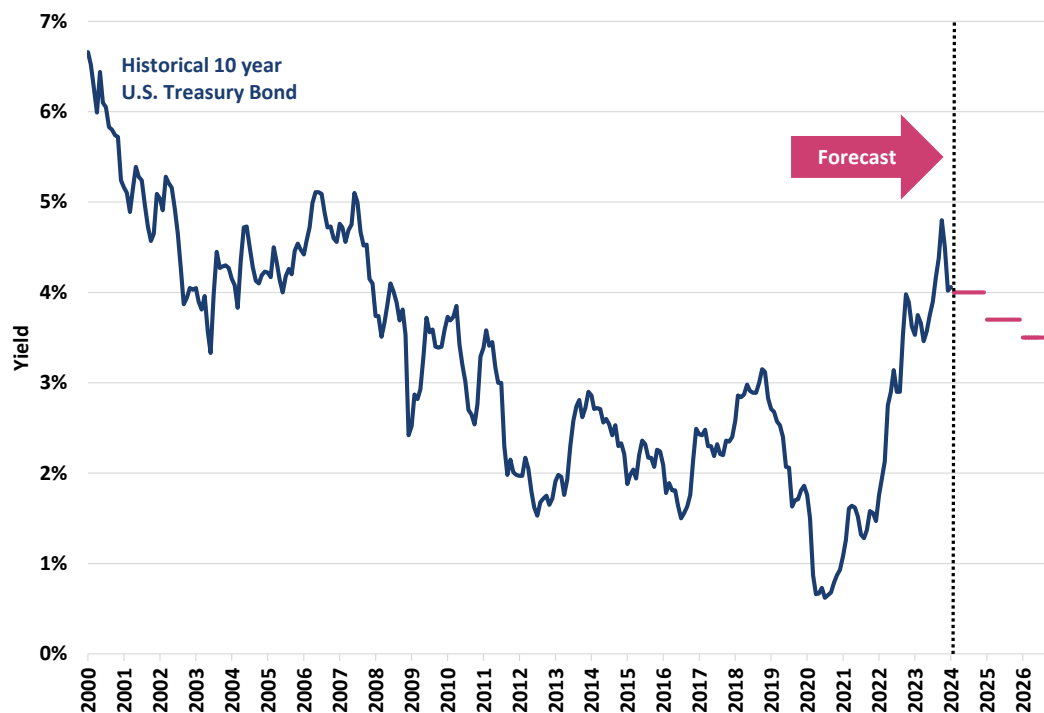
36 *Wolters Kluwer, Blue Chip Economic Indicators*, Vol. 49, No. 1, January 10, 2024, pp. 2-3.

37 *Wolters Kluwer, Blue Chip Economic Indicators*, Vol. 49, No. 2, February 9, 2024, pp. 2-3

1 10-year yield to be 4.8 percent.³⁸ Further, the materials released after the December
2 2023 FOMC meeting indicate that the Federal Funds rate will be 4.6% in 2024.³⁹

3 Figure 4 below shows the development in the 10-year Treasury bond yield as well as
4 the forecast for the 10-year yield. Notably, the current yield as well as the forecasted
5 yield is higher than in the recent past.

6 **Figure 4: Historical and Projected 10-year Treasury Bond Yields⁴⁰**



7
8 Lastly, I note that while the yield on Baa rated corporate bonds is expected to remain
9 above 6.0 percent during 2024. This yield averaged 5.6 percent in February 2023,

38 The Congressional Budget Office expects the 10-year Treasury yield at 4.8 percent in Q4, 2024 ([51135-2023-12-Economic-Projections.xlsx \(live.com\)](#)). Other forecasts indicates a 20-year Treasury bond yield of 4.55 percent for June 2024 by World Government Bonds ([United States 20 Years Bond - Forecast \(worldgovernmentbonds.com\)](#));

39 Federal Reserve, "Summary of Economic Projections," December 13, 2023, p. 2, [Summary of Economic Projections, December 13, 2023 \(federalreserve.gov\)](#)

40 Bloomberg as of January 16, 2024 and *Blue Chip Economic Indicators*, January 10, 2024.

1 increased through most of 2023 and then declined to 5.6% again in December 2024.⁴¹

2 Thus, indications are that the corporate bond yield will remain high through 2024.

3 **B. Yield Spreads**

4 **Q24. Why are bond yield spreads relevant to a cost of equity analysis?**

5 A24. Bond yield spreads (also called credit spreads) reflect the premium that investors
6 demand to hold debt securities (specifically corporate or utility bonds) that are not risk
7 free. Analogously, the MRP—which is a key input to the CAPM—represents the risk
8 premium that investors require to hold a market portfolio of equities rather than risk-
9 free government bonds.

10 If bond yields are influenced by some of the same underlying market forces that drive
11 the systematic risk premium for equities, shifts in directly observable credit spreads can
12 assist with inference about changes in the MRP, which itself must be estimated.⁴² More
13 specifically, if both credit spreads and equity premiums are determined in part of the
14 general premium required by investors for bearing systematic risk, then an increase in
15 credit spreads may indicate an increase in the forward-looking MRP.

16 **Q25. How does the current spread between utility and U.S. Government bond yields**
17 **compare to historic spreads?**

18 A25. At present (January 2024), the spread between 20-year BBB-rated utility bond yields
19 and 20-year U.S. government bond yields is 1.29%.⁴³ This compares to a long-term
20 historic average spread of 1.23% prior to the financial crisis and 1.54% for the period

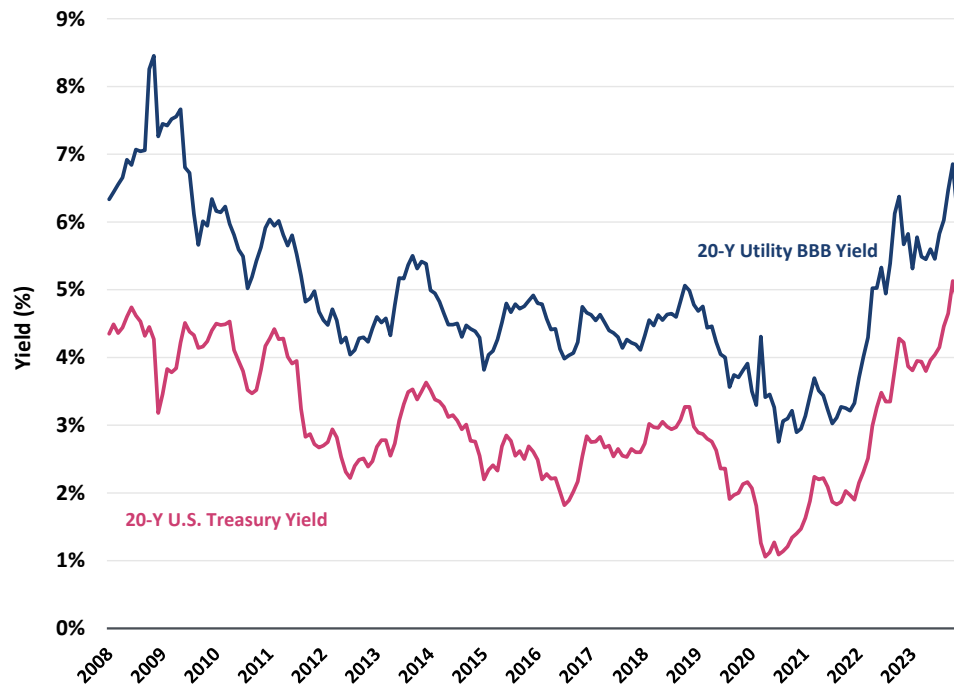
⁴¹ Sources: Federal Reserve, FRED, Moody's Seasoned Baa Corporate Bond Yield, Percent, Monthly, Not Seasonally Adjusted and Blue Chip Financial Forecasts, December 28, 2023. I refer to the corporate yield as I do not know of sources that forecast the utility bond yield.

⁴² This is the same issue as in cost of capital estimation more generally: the cost of debt can often be directly observed in the form of market bond yields, whereas the cost of equity must be estimated based on financial models.

⁴³ Bloomberg as of February 13, 2024. The data for December 2023 are similar.

1 1990 through 2023,⁴⁴ so currently the spread is comparable the long-run average.
 2 Importantly, the current (December 2023) yield on utility bonds remains higher than at
 3 any time since 2013.

4 **Figure 5: Yield on BBB-rated Utility Bonds and 20-Year Treasury Bonds⁴⁵**



5
6

7 C. Risk Premiums

8 Q26. How do risk premiums affect the cost of equity?

9 A26. Risk premiums provide an indication of the compensation investors expect to hold
 10 securities that are not risk-free. If an investor demands a larger risk premium, then the
 11 cost of equity will be larger. There are several indicators of risk premiums in addition
 12 to the yield spreads discussed above. For example, indicators such as stock market
 13 volatility (e.g., VIX) provide insights into the risk premium required by investors in the

44 *Ibid.*, Average for prior to the financial crisis is for the period April 1991 to 2007.

45 Bloomberg as of January 16, 2024.

1 coming 30 days. SKEW provides a useful indicator of volatility over the next 12
2 months. Whereas the MRP measures the compensation required to hold a security over
3 a long investment horizon, such as the period when rates set in this proceeding will be
4 in effect. For this reason, the forecast MRP needs to be taken into consideration when
5 determining the cost of equity in this proceeding.

6 **Q27. What is the current evidence regarding market volatility and investors' risk**
7 **perception?**

8 A27. Measures of market volatility are slightly below long-term averages. For example, VIX
9 is currently around 15 but was higher at about 22 at the end of October 2023 – these
10 figures are a bit below the long-run average of about 19.5.⁴⁶ However, the SKEW
11 index, which measures the market's willingness to pay for protection against negative
12 "black swan" stock market events (i.e., sudden substantial downturns),⁴⁷ shows that
13 investors remain cautious. A SKEW value of 100 indicates outlier returns are unlikely,
14 but as the SKEW increases, the probability of outlier returns becomes more significant.
15 The SKEW index is currently 148.⁴⁸ While the VIX shows close to historical volatility
16 going forward, the SKEW indicates investors are cautious.

17 During the last several month, investors have seen several bank failures,⁴⁹ the on-going
18 wars in Ukraine and Israel, and the unprecedented mix of monetary tightening (e.g., the
19 raises to interest rates described above) and fiscal stimulus (e.g., the Inflation Reduction
20 Act of 2022⁵⁰). Consequently, the evidence regarding investors' risk perception is
21 mixed.

22 **Q28. What is the Market Risk Premium?**

46 Cboe, VIX, accessed January 17, 2024, https://www.cboe.com/tradable_products/vix/

47 Cboe, SKEW, accessed January 17, 2024, <https://www.cboe.com/us/indices/dashboard/skew/>

48 *Ibid.*

49 First Public Bank, Silicon Valley Bank, and Signature Bank collapsed in 2023.

50 Inflation Reduction Act, H.R. 5376, <https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf>

1 A28. In general, a risk premium is the amount of “excess” return—above the risk-free rate
2 of return—that investors require to compensate them for taking on risk. As illustrated
3 in Figure 2 above, the riskier the investment, the larger the risk premium investors will
4 require.

5 The market risk premium (“MRP”) is the risk premium associated with investing in the
6 market as a whole. Since the so-called “market portfolio” embodies the maximum
7 possible degree of diversification for investors,⁵¹ the MRP is a highly relevant
8 benchmark indicating the level of risk compensation demanded by capital market
9 participants. It is also a direct input necessary to estimating the cost of equity using the
10 CAPM and other risk-positioning models.

11 **Q29. Please explain the current evidence on the MRP.**

12 A29. As of 2023, the historic MRP has declined slightly relative to the last few years due
13 primarily to higher returns on government bonds. Specifically, for the period 1926
14 through 2022, the average historic MRP was 7.17%.⁵² At the same time, the forecast
15 MRP from Bloomberg was 6.37%, relative to a 20-year Treasury bond, as of December
16 29, 2023.⁵³ Using the FERC methodology, the forecasted MRP was 7.69% over the 20-
17 year Treasury bond yield using IBES growth rates and 7.71% using Value Line growth
18 rates.⁵⁴

19 **D. Inflation Expectations and Impact**

20 **Q30. Why is inflation relevant to estimating the cost of equity for DTE Electric?**

51 In finance theory, the “market portfolio” describes a value-weighted combination of all risky investment assets (e.g., stocks, bonds, real estate) that can be purchased in markets. In practice, academics and financial analysts nearly always use a broad-based stock market index, such as the S&P 500, to represent the overall market.

52 Kroll, U.S. Cost of Capital Navigator, January 2024.

53 Bloomberg data as of January 16, 2024.

54 Exhibit D5.17, estimated as of December 31, 2023.

1 A30. The return on equity that is being determined is expected to be in effect for a period
2 time going forward and the ROE is measured in nominal terms—meaning that it
3 includes the expected inflation. The Federal Reserve forecasts that inflation will be
4 elevated through at least 2025,⁵⁵ while the BCEI expect inflation to be elevated through
5 at least 2024.⁵⁶ Thus, for at least the next year inflation is expected to be above the
6 Federal Reserve’s target level of 2% on average.

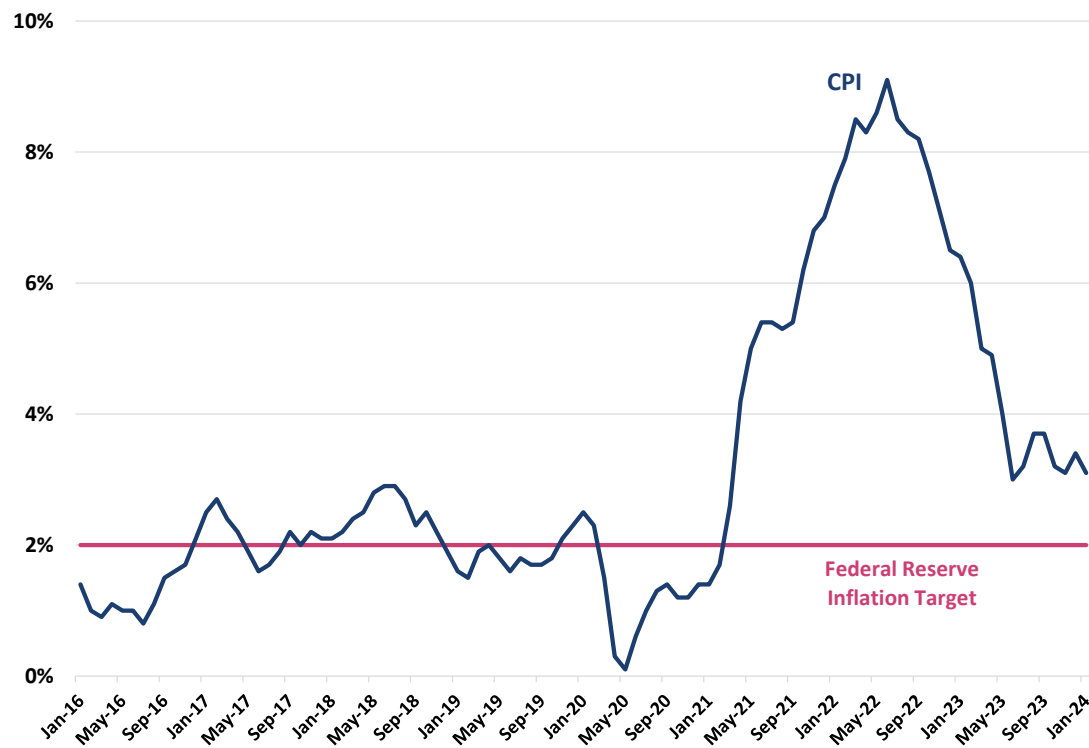
7 **Q31. What are the recent indicators of inflation for the U.S. economy?**

8 A31. Inflation, as measured by CPI, reached a recent high of 9.1% in June 2022. Since then,
9 inflation has decreased to between 3.1% and 6.4% in 2023 with the most recent data
10 for December 2023 and January 2024 being 3.4% and 3.1%, respectively (see Figure 6
11 below). Thus, while the inflation rate has come down it remains well above the Federal
12 Reserve’s target of 2.0% on average.

55 Federal Reserve, “Summary of Economic Projections,” September 20, 2023, p. 2. This view was affirmed in the FOMC’s December 2023 Summary of Economic Projections.

56 *Blue Chip Economic Indicators*, February 9, 2024, pp. 2-3. The January 2024 issue had the same inflation expectations.

1 **Figure 6: Inflation as Measured by the Consumer Price Index⁵⁷**



2

3 Looking forward, recent surveys by economists, such as the *BCEI* survey, indicate that
 4 U.S. inflation will be 2.6% in 2024 and 2.2% in 2025.⁵⁸

5 **Q32. Are there other factors that may impact the financial conditions for utilities such**
 6 **as DTE Electric?**

7 A32. Yes. The evolving situation in the Middle East has the potential to substantially impact
 8 economic policy, world markets and especially energy markets.⁵⁹ The unrest may cause
 9 investors to change their risk tolerance and hence the return they require to invest in

⁵⁷ Bureau of Labor Statistics.

⁵⁸ *Blue Chip Economic Indicators*, February 2024 pp. 2-3.

⁵⁹ I acknowledge there are many non-economic aspects to this conflict but discuss only the factors that may impact the cost of equity for utilities in the US.

1 assets that are not risk-free. Because the Middle East is a large supplier of energy, it
2 could impact inflation and financial markets more broadly.

3 **Q33. Please summarize how economic developments discussed above have affected the**
4 **return on equity and debt that investors require.**

5 A33. Utilities rely on investors in capital markets to provide funding to support their capital
6 expenditure programs and efficient business operations. Investors consider the risk-
7 return tradeoff in choosing how to allocate their capital among different investment
8 opportunities. It is therefore important to consider how investors view the current
9 economic conditions, including the plausible development in the risk-free rate,
10 inflation, and other key indicators.

11 These investors have been affected by the development in interest rate and inflation
12 that remains above the Federal Reserve's target, so there are reasons to believe that
13 their return expectations reflect the increase in interest rates and higher than usual
14 inflation.

15 **V. ESTIMATING THE COST OF EQUITY**

16 **A. APPROACH TO COST OF EQUITY ESTIMATION**

17 **Q34. Can you explain your approach to estimating the cost of equity for DTE Electric?**

18 A34. As discussed in Section IV, the financial and economic conditions are impacted by a
19 variety of factors; including rising interest rates and high inflation.

20 In the remainder of Section V, I present the inputs, assumptions, and results from my
21 cost of equity estimation methods.

22 **B. PROXY GROUP SELECTION**

23 **Q35. How do you identify sample companies of comparable business risk to DTE**
24 **Electric?**

1 A35. DTE Electric is a regulated electric utility. The business risk associated with these
2 business activities depend on several factors, including the specific characteristics of
3 the service territory and regulatory environment in which the utility operates.
4 Consequently, it is not possible to identify publicly traded companies that replicate
5 every aspect of DTE Electric's business risk profile. However, an appropriate starting
6 pointing to create proxy groups of comparable business risk to DTE Electric is to select
7 other companies whose primary business operations are concentrated in regulated
8 industries or companies that have similar lines of business and/or business
9 environments. As a second step, I must evaluate DTE Electric or Michigan-specific
10 risks to ensure that the Company's ROE is appropriately placed relative to the proxy
11 samples.

12 To that end, I have selected a proxy group composed of regulated utility companies
13 that focus on (i) the provision of electricity to end-users ("Electric Utility Proxy
14 Group").⁶⁰ This proxy group is similar to DTE Electric in that they are rate regulated
15 by state utility commissions, serve customers through a network of assets, and rely on
16 substantial capital to provide service—that is, they are capital intensive like DTE
17 Electric.

18 It is important that the proxy groups used to assess the cost of equity for DTE Electric
19 (absent any unique Michigan or Company specific characteristics) are comprised of
20 regulated entities, because regulation tends to place substantial requirements and
21 protections on the companies. I also believe the physical characteristics of the
22 industry—*e.g.*, network, capital intensive, serving many different customers—are
23 characteristics of DTE Electric and of other highly regulated utilities. The network
24 characteristic implies that assets cannot readily be employed in a different capacity; the
25 capital intensive characteristic affects the operating risks through the split between
26 fixed and variable costs; and the customer composition affects the demand risk.

60 To reduce the number of disagreements with Staff, I have eliminated the natural gas distribution utilities.

1 **Q36. How do you identify suitable utilities for inclusion in your proxy groups?**

2 A36. First, I start with the universe of publicly traded electric utilities reported by Value Line
3 Investment Analyzer (“Value Line”). It is necessary to focus on publicly traded
4 companies because non-traded entities do not have the necessary stock price data to
5 utilize the financial models relied upon to estimate the cost of equity. Second, I narrow
6 down this universe of electric, utilities identified by Value Line using the following
7 screening criteria:

- 8 • Must be an investment grade utility,
- 9 • Must have a market capitalization greater than \$300 million (to avoid micro
- 10 caps),
- 11 • Must pay dividends with no dividend cuts for three years,
- 12 • Cannot have engaged in substantial merger, acquisition, or divestiture activity
- 13 for three years,

14 and

- 15 • Must have sufficient data for estimation.

16 Third, I review business descriptions and financial reports of these companies and
17 eliminate those that have less than 50% of their assets dedicated to regulated utility
18 activities. Within this group of companies, I apply further screening criteria to eliminate
19 companies with recent significant events (*i.e.*, litigation) that could affect the market
20 data necessary to perform cost of capital estimation.

21 To the degree that a subset or subsets of these utilities have risk characteristics that
22 match those of DTE Electric to a larger degree, subset(s) will be created and analyzed.

23 **Q37. What are the results of your sample selection process?**

24 A37. The selection process produced a proxy group of 25 integrated, regulated electric
25 utilities of which one (Exelon) lacks a beta from Value Line.⁶¹

26 **Q38. What are the characteristics of your Electric Utility Proxy Group?**

61 Relative to my direct testimony in U-21297, I eliminate Dominion Energy due to its large divestiture.

1 A38. The Electric Utility Proxy group is comprised of electric utilities, whose primary source
2 of revenues and the majority of its assets are subject to regulation. The final proxy
3 group consists of 25 electric utilities listed in Figure 7 below.⁶² These companies own
4 regulated electric utility subsidiaries and are classified by EEI as either “regulated”
5 (having at least 80% of their assets dedicated to regulated utility operations) or “mostly
6 regulated” having less than 80% regulated assets.⁶³ (These EEI categories are
7 designated with an “R” or “M” in the Figure below). Therefore, the Electric Utility
8 Proxy Group is broadly representative of the regulated electric industry from a business
9 risk perspective.

10 The market capitalization, betas, and growth estimates for both cost of equity
11 estimation dates are presented side-by-side. The annual revenue as well as the market
12 capitalization was obtained from Bloomberg. The credit rating is reported by
13 Bloomberg. The growth rate estimate is a weighted average between estimates from
14 Thomas Reuters and *Value Line*. The betas were obtained from *Value Line* as of
15 December 31, 2023. The categorization was based on the companies’ most recent 10-
16 K.

62 Relative to my testimony for DTE Electric in U-21297, I have eliminated Dominion Energy as Dominion sold substantial gas distribution assets to Enbridge Inc. in September 2023.

63 Edison Electric Institute (EEI), Financial Report, 2022. As of February 13, 2024, the 2023 data were not available. Note: I eliminate any companies with less than 50% of regulated assets. See Appendix B for further detail.

1

Figure 7: Electric Utility Sample

Company	Annual Revenue (Q4 2023) (\$MM) [1]	Regulated Assets [2]	Market Cap. (Q4 2023) (\$MM) [3]	Value Line Beta [4]	S&P Credit Rating [5]	Long-Term Growth Estimate [6]
ALLETE	\$1,856	MR	\$3,509	0.95	BBB	5.8%
Alliant Energy	\$4,143	R	\$13,077	0.90	A-	6.9%
Amer. Elec. Power	\$19,747	R	\$42,680	0.80	A-	5.2%
Ameren Corp.	\$7,942	R	\$19,455	0.90	BBB+	5.6%
Avista Corp.	\$1,614	R	\$2,744	0.95	BBB	5.9%
Black Hills	\$2,147	R	\$3,700	1.00	BBB+	4.7%
CMS Energy Corp.	\$7,185	R	\$16,914	0.85	BBB+	6.9%
CenterPoint Energy	\$8,374	R	\$18,194	1.15	BBB+	5.0%
Duke Energy	\$29,842	R	\$74,426	0.90	BBB+	6.4%
Edison Int'l	\$17,334	R	\$26,793	1.00	BBB	5.1%
Entergy Corp.	\$13,018	R	\$21,439	0.95	BBB+	0.9%
Evergy Inc.	\$5,990	R	\$11,915	0.95	BBB+	5.1%
Exelon Corp.	\$22,341	R	\$36,500	n/a	BBB+	9.0%
IDACORP Inc.	\$1,865	R	\$4,978	0.85	BBB	4.3%
MGE Energy	\$686	R	\$2,620	0.75	AA-	4.5%
NextEra Energy	\$28,409	MR	\$124,492	1.00	A-	8.2%
NorthWestern Corp.	\$1,387	R	\$3,151	0.95	BBB	4.2%
OGE Energy	\$3,053	R	\$7,074	1.05	BBB+	11.3%
Otter Tail Corp.	\$1,393	R	\$3,428	0.95	BBB	-13.1%
Pinnacle West Capital	\$5,342	R	\$8,270	0.95	BBB+	6.6%
Public Serv. Enterprise	\$11,088	R	\$30,750	0.95	BBB+	5.4%
Sempra Energy	\$16,563	R	\$23,414	1.00	BBB+	7.5%
Southern Co.	\$26,188	R	\$77,031	0.95	BBB+	7.9%
WEC Energy Group	\$8,633	R	\$26,358	0.85	A-	5.8%
Xcel Energy Inc.	\$14,426	R	\$34,132	0.85	A-	6.2%
Electric Sample	\$10,423	R	\$25,482	0.93	BBB+	5.3%

2

3 **Q39. How does the proxy group compare to DTE Electric in terms of financial metrics?**

4 A39. DTE Electric's regulated electric operations generated an annual revenue of 6,397 MM
5 in 2022,⁶⁴ which is lower than the average annual revenues for the Electric Utility proxy
6 groups. DTE Electric's S&P senior unsecured credit rating is BBB, which is similar to
7 the Electric Utility proxy group average. DTE Electric is a regulated entity as are all of
8 my proxy companies. The proxy groups, like DTE Electric, operate a capital-intensive
9 network of assets, which are subject to state regulation. I discuss below further the
10 similarities and differences between DTE and the proxy group focusing on the

⁶⁴ DTE 2022 10-K, p. 32.

1 composition of generation, capital needs, and the availability of regulatory
2 mechanisms.

3 **C. FINANCIAL RISK ADJUSTMENT**

4 **Q40. Can you explain the difference between the data relied upon to estimate the cost**
5 **of equity and the regulatory rate base to which the cost of equity is applied?**

6 A40. Both the CAPM and the DCF models rely on market data to estimate the cost of equity
7 for the sample companies, so the results reflect the value of the capital that investors
8 hold during the estimation period (market values). The allowed return on equity is
9 applied to rate base, which is determined using historical cost and hence reflect the
10 (net) book values of assets.

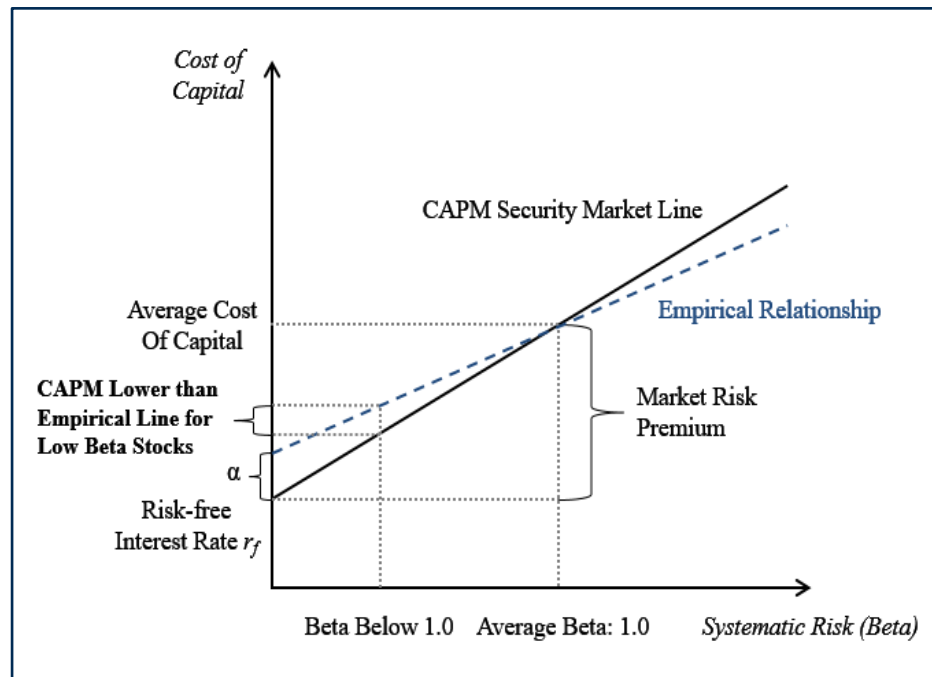
11 **Q41. Why is this difference important to the estimation of the cost of equity?**

12 A41. Taking the level of financial risk or leverage into account is necessary to reflect the fact
13 that different capital structure ratios have different levels of financial risk. Specifically,
14 all else equal, higher levels of debt financing increases the risk faced by equity
15 investors. Therefore, investors require higher ROEs from companies with more debt
16 than from comparable business risk companies with less debt. To reflect the effect of
17 capital structure on the cost of equity, I adjust the cost of equity estimates I obtain from
18 applying the models to the market data of the proxy companies. I do so using two
19 different approaches: (1) the overall cost of capital approach and (2) the Hamada
20 approach. I provide further details of these two approaches in Appendix B.⁶⁵

65 In recognition of the Commission's past decision to not rely on the overall cost of capital approach, my CAPM / ECAPM recommended range is based on the Hamada approach. This approach cannot be applied to the DCF model.

1 The alpha adjustment has the effect of increasing the intercept but reducing the slope
 2 of the Security Market Line in Figure 8, which results in a Security Market Line that
 3 more closely matches the results of empirical tests. The impact on the Security Market
 4 Line is illustrated in Figure 8 below. In the ECAPM implementation, I use an alpha of
 5 1.5 based on academic research documenting the magnitude of alpha.⁶⁶

6 **Figure 8**
 7 **The Empirical Security Market Line**



8

9 3. CAPM/ ECAPM Cost of Equity Estimates

10 **Q44. Can you summarize the parameters of the scenarios you considered when**
 11 **conducting your CAPM and ECAPM analyses?**

66 See Black, Fisher. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18; Black, Fisher, Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests. *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, pp. 79-121. New York: Praeger; Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): pp. 607-636; Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): pp. 427-465; Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): pp. 25-46.

A44. I performed each CAPM/ ECAPM analysis using two scenarios to obtain a range of cost of equity estimates. Specifically, I rely on a forecasted risk-free rate and (i) a historical MRP or (ii) a forecasted MRP.

In Scenario I, I use the average forecasted risk-free rate for 2024-2025, which I determined as the 10-year forecast by Blue Chip Economic Indicators plus 50 basis points, which is the average maturity premium of a 20-year government bond yield over the 10-year government bond yield.⁶⁷ This gives me a risk-free rate of 4.30 percent, which is comparable to the December 2023 yield of approximately 4.32 percent.⁶⁸ In Scenario I, I combine this risk-free rate with the historical average MRP as provided by Duff & Phelps.⁶⁹ In Scenario II, I use Bloomberg's forecasted MRP (over the 20-year Treasury bond yield) for a MRP of 6.37 percent.⁷⁰

Figure 9
Scenarios in CAPM/ ECAPM Analysis

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.30%	4.30%
Market Risk Premium	7.17%	6.37%

I note that relative to the time of DTEE's filing in U-21297, the forecasted risk-free rate and the actual risk-free rate have increased as has the forecasted MRP, while the historical MRP has declined very modestly.

⁶⁷ *Blue Chip Economic Indicators*, January 10, 2024. I use the 20-year government bond yield because the historical MRP is calculated over an approximately 20-year government bond yield. The February 2024 issue of *Blue Chip Economic Indicators* show a slightly higher forecast for the 2024 risk-free rate at 4.0 percent as compared to the 3.9 percent in January 2024.

⁶⁸ Bloomberg as of December 31, 2023.

⁶⁹ The MRP of 7.17% is sourced from Duff & Phelps, *Cost of Capital Navigator*.

⁷⁰ Bloomberg as of December 31, 2023. Bloomberg calculates the MRP over the 10-year government bond yield as 6.87%. I subtract 50 basis points as that is my estimate of the average maturity premium of the 20-year government bond over the 10-year government bond.

1 **Q45. Can you summarize the results from your CAPM and ECAPM analyses?**

2 A45. The results from the CAPM and ECAPM models are presented in Figure 10 below.

3 **Figure 10: CAPM/ ECAPM Cost of Equity Estimates**
 4 **Electric Sample**

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Electric Sample		
<i>Hamada Adjustment Without Taxes</i>		
CAPM	11.7%	10.9%
ECAPM ($\alpha = 1.5\%$)	11.7%	10.8%
<i>Hamada Adjustment With Taxes</i>		
CAPM	11.7%	10.9%
ECAPM ($\alpha = 1.5\%$)	11.7%	10.9%

5

6 **Q46. How do you interpret the result of your CAPM and ECAPM analyses?**

7 A46. First, there is very little difference between the CAPM and ECAPM results at this point
 8 in time. Second, the Electric Utility Sample's results are consistent with a cost of equity
 9 in the range of 10.75 percent to 11.75 percent (rounding to the nearest $\frac{1}{4}$ percent).⁷¹
 10 Relative to the results reported in the U-21297 matter, the range is narrower and the
 11 lower bound has increased.⁷²

12 **E. DCF APPROACH AND COST OF EQUITY ESTIMATES**

13 **Q47. Can you describe the discounted cash flow approach to estimating the cost of**
 14 **equity?**

71 I note that I do not report the results from the financial risk adjustment method for the CAPM method and ignore them in my recommendation as the Commission in the past has been critical of the approach.

72 I note that prior to applying the Hamada method, the average ROE from the CAPM model is 11.0 percent using the historical average MRP and 10.2 percent using the forecasted MRP for an average of 10.6 percent.

1 A47. The DCF model estimates the cost of capital for a given company directly, rather than
 2 based on its risk relative to the market as the CAPM does. There are two variations of
 3 the DCF model, the single-stage DCF and multi-stage DCF, as explained below.

4 1. Single-Stage DCF Approach

5 Q48. Can you please briefly describe the single-stage DCF and the inputs used to
 6 determine the cost of equity?

7 A48. Yes. The single-stage DCF model assumes that the current market price of a stock is
 8 equal to the present value of the dividends that its owners expect to receive. The
 9 expected stream of future dividends is discounted at a risk-appropriate rate to arrive at
 10 the present value of the dividends, represented by the current stock price. In this
 11 application of the DCF, the risk-appropriate rate is the cost of equity. Mathematically,
 12 the DCF model is shown in the formula below:

13 Formula 3

$$14 \quad P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \dots + \frac{D_T}{(1+r)^T}$$

15 where P_0 is the current market price of the stock;

16 D_t is the dividend expected at the end of period t ;

17 T is the last period in which a dividend is to be received; and

18 r is the cost of equity capital.

19 Formula 3 implies that if one knows the current market price of a stock and its expected
 20 stream of future dividends, then it is possible to solve for the cost of equity r . The
 21 single-stage DCF model assumes that the stream of future dividends will grow at a
 22 constant rate into perpetuity. This assumption allows Formula 3 to be algebraically
 23 rearranged into the formula below to directly estimate the cost of equity:

24 Formula 4

$$25 \quad r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g$$

26 where D_0 is the current dividend; and

1 g is the constant growth rate of the current dividend.

2 Another variation of the DCF model relaxes the restrictive constant growth rate
3 assumption and instead, allows the dividend to grow at different rates at different points
4 in time. This variation is known as the multi-stage DCF model and is further explained
5 below.

6 **2. Multi-Stage DCF Approach**

7 **Q49. Can you briefly describe the multi-stage DCF and the inputs used to determine**
8 **the cost of equity?**

9 A49. The multi-stage DCF accommodates different dividend growth rates at different points
10 in time. Specifically, in the implementation of the multi-stage DCF, I assume three
11 different growth rate phases. In the first phase, companies grow their dividend for five
12 years at the forecasted company-specific rate of earnings growth. In the second phase,
13 the company-specific growth rate incrementally steps down (or steps up) to the overall
14 growth rate of the economy, represented by the long-term GDP growth rate. Finally, in
15 the third phase, companies grow their dividend at the long-term GDP growth rate into
16 perpetuity.

17 I calculate both the single- and multi-stage DCF using growth rates from *Value Line*
18 and *IBES* as well as GDP forecasts from Blue Chip Economic Indicators in the case of
19 the multi-stage DCF. The growth rates utilized in the DCF implementations are shown
20 in Figure 7 above.

21 **3. DCF Cost of Equity Estimates**

22 **Q50. What are the results from your DCF based cost of equity estimates for your**
23 **samples?**

24 A50. The financial risk adjusted single- and multi-stage DCF cost of equity estimates are
25 presented in Figure 11 below.

Figure 11: DCF Cost of Equity Estimate

	Simple	Multi-stage
Electric Sample	11.2%	9.4%

In addition to the results above, I note that the average of the simple DCF calculations before any financial risk considerations is 10.5 percent.⁷³

Q51. How do you interpret the results from your DCF analyses?

A51. The range of estimates obtained from the DCF methods range from 9.4 percent to 11.2 percent (9.5% to 11.25% rounding to the nearest ¼ percent). Relative to the results I obtained in my direct testimony for U-21297 both the lower and upper bound has increased by 0.50 percent. I view the multi-stage results as unrepresentative because they (1) are out of line with other results (2) may fail to capture the substantial growth needed in the electric sector to accomplish the transition to low-carbon economy, which may require a higher growth for a prolonged period of time. I also consider the very high end unrepresentative. Consequently, I consider the narrower range of 10.0 to 11.0 percent for the Electric Sample and note the results from the simple DCF without adjustments fall at the middle of that range.

F. RISK PREMIUM APPROACH AND COST OF EQUITY ESTIMATE

Q52. Can you briefly describe the Risk Premium approach to estimating the cost of equity?

A52. The Risk Premium approach adds a “risk premium” to the current risk-free rate to estimate the current cost of equity, as shown in Formula 5 below.

⁷³ Schedule D5.6, Panel A. The calculation ignores results below the yield on BBB rated debt.

Formula 5

$$\text{Cost of Equity} = r_f + \text{Risk Premium}$$

The risk premium component of Formula 5 is estimated using the allowed ROEs and prevailing risk-free rates from past utility rate cases. In our implementation, I calculate the risk premium as the difference between allowed ROEs and the prevailing quarterly 20-year Treasury bond yield over the period 1990-Q4, 2023.⁷⁴ This difference represents the compensation for risk allowed by regulators. I use the statistical technique of ordinary least squares (OLS) regression to estimate the parameters of the linear equation:

Formula 6

$$\text{Risk Premium} = A_0 + A_1 \times (r_f)$$

where A_0 and A_1 are parameters to be estimated by the regression technique; and

r_f is the risk-free rate as measured by the 20-year Treasury bond yield.

Q53. How are the parameters to the Risk Premium approach estimated?

A53. The parameters estimated by regression analysis (*i.e.*, OLS) are shown in Figure 12 below. Additionally, the regression analysis finds that the risk-free rate has a high degree of statistical explanatory power in capturing changes in the risk premium. The negative coefficient A_1 reflects the empirical fact that regulators grant lower risk premiums—and by extension, lower allowed ROEs—when the risk-free rate is higher. This is consistent with the observation that investors require a higher risk premium to hold equities over government bonds as bond yields decline. I then use the parameters from the regression analysis, A_0 and A_1 , to estimate the cost of equity using the risk-free rate of 4.30 percent. As the prevailing risk-free rate of 4.32 percent is virtually similar, I do not report results from using that figure.

⁷⁴ I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

1 **Q54. Can you describe the results from your Risk Premium model?**

2 A54. Applying the calculated risk premium and a risk-free rate of 4.30% to Formula 5 above
3 results in an estimated cost of equity of 10.5% for electric utilities. These results are
4 depicted in Figure 12 below.

5 **Figure 12: Implied Risk Premium Model Estimate: Electric Utilities**

	R Squared	Estimate of Intercept (A0)	Estimate of Slope (A1)	Implied Cost of Equity Range
	[1]	[2]	[3]	[4]
Electric Utility	85.6%	8.6%	-56.3%	10.5%

6

7 **Q55. How do you interpret the results from your Risk Premium model?**

8 A55. Based on the Risk Premium model using the forecasted interest rate indications, an
9 average ROE for the average electric utility is 10.5 percent. This range is consistent
10 with the estimates obtained from the CAPM and the DCF model for the Electric Utility
11 Sample. I note that the R-squared is 85.6%, so that the regression has a high degree of
12 explanatory power.

13 **G. SUMMARY RESULTS**

14 **Q56. Can you briefly summarize the results from the various models you employed to**
15 **estimate the cost of equity for DTE Electric.**

16 A56. Based on the discussions above, I obtain the following estimates for my proxy groups.

Figure 13: ROE Estimates

	Electric Sample		Reasonable Range	
	Low	High	Low	High
CAPM / ECAPM	10.8%	11.7%	10.75%	11.75%
DCF	9.4%	11.2%	9.50%	11.00%
Risk Premium	10.5%	10.5%	10.50%	10.50%
Average	10.2%	11.1%	10.25%	11.08%
Midpoint	10.70%		10.67%	

The average of the low and high is 10.2 percent and 11.1 percent, respectively with the reasonable range being close at approximately 10.25 to 11.0 percent for the electric sample.

I note that DTE Electric's requested ROE of 10.5 percent is below the midpoint of my estimates by within the range of my reasonable estimates. Consequently, I view the requested ROE as conservative and especially so given DTEE's risk profile, which indicates the company has higher business risk than the comparable companies.

VI. DTE ELECTRIC SPECIFIC CIRCUMSTANCES AND ROE RECOMMENDATION

A. REGULATORY ENVIRONMENT

Q57. Are there any differences in the regulatory environment in which the comparable companies and DTE Electric operates?

A57. Like many of the sample companies, DTE Electric benefits from certain regulatory policies that reduce regulatory lag, including a forward test year for rate cases, and an annual Power Supply Cost Recovery ("PSCR") clause for expenses such as fuel, capacity, energy, transmission, and purchased power.⁷⁵ Subject to Commission review,

⁷⁵ S&P Global Market Intelligence, Commission Details for the Michigan Public Service Commission, accessed November 8, 2022, <https://platform.mi.spglobal.com/interactivex/CommissionDetails.aspx?Printable=1&id=4081574&Type=1&State=MI>.

1 the Company is permitted to include construction work in progress (“CWIP”) for
 2 pollution control measures and significant new infrastructure projects in rate base.⁷⁶
 3 Cost-tracking mechanisms such as these are also in effect in states affecting several of
 4 the sample companies.⁷⁷ However, unlike some of the sample companies, DTE Electric
 5 does not currently have a revenue decoupling mechanism (since a 2012 Court of
 6 Appeals ruling reversed Michigan Public Service Commission approval for such a
 7 program that DTE Electric had implemented) or lost revenue adjustment mechanism
 8 (“LRAM”) in place, as some sample companies do.⁷⁸

9 A more complete listing of regulatory mechanisms available to DTE and the companies
 10 in the electric proxy group is included in Exhibit D5.19. I discuss the findings from this
 11 comparison below.

12 **Q58. Are there any differences to the sample?**

13 A58. Yes. First, as noted above, Michigan does not have a decoupling or decoupling-like
 14 mechanism for electric utilities. Combined with the partial electric choice in Michigan,
 15 this could create a downward risk for DTE Electric. Second, DTE Electric relies to a
 16 larger degree than many of the comparators on nuclear generation (about 19 percent).
 17 Nuclear generation is associated with certain risks. Third, a relatively large proportion
 18 of DTE Electric’s generation is coal based (approximately 45 percent in 2023)⁷⁹
 19 meaning that if Michigan’s Healthy Climate Plan’s goal of 50 percent renewable by

⁷⁶ *Id.*

⁷⁷ Lillian Federico, “Alternative ratemaking plans in the U.S.,” S&P Global Market Intelligence, Regulatory Research Associates. April 16, 2020, accessed April 21, 2020, <https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/article?id=58062563&KeyProductLinkType=6>. Checked for updates July 31, 2021.

⁷⁸ *Edison Electric Institute*, “Alternative Regulation for Evolving Utility Challenges: An Updated Survey,” January 2013. Many of the companies in my comparable sample have a decoupling mechanism in place. This means that these companies benefit from regulatory provisions allowing them to recover their fixed costs independent of volumetric charges: if the utilities’ customers use less electricity than was forecast, the decoupling mechanism ensures that the utilities can recover their cost despite the decrease in variable revenues.

⁷⁹ DTE, “DTE Business Update,” December 8, 2023.

1 2030 is to be reached,⁸⁰ then DTEE will need to replace substantial parts of its
2 generation fleet – leading to the need for large investments, which create execution
3 risks as well as increases the proportion of fixed expenses, which all else equal,
4 increases risk. Additionally, DTE Electric has a higher than average for the proxy
5 companies reliance on nuclear power (19% versus the sample average of 8%).⁸¹

6 Looking to the regulatory mechanisms that are available to companies in the sample
7 and DTE Electric, I note (in addition to DTEE’s lack of a decoupling mechanism) that
8 DTEE similar to most other electric utilities’ operating entities has an electric fuel
9 purchase power adjustment clause. Similar to nearly half of the regulated operating
10 entities, DTEE has access to a renewable/non-traditional generation rider, but unlike
11 about 40 percent of the operating entities owned by the sample companies, DTEE does
12 not have access to delivery infrastructure or environmental compliance riders.⁸²
13 Overall, I do not see any major differences in access to regulatory mechanisms other
14 than the lack of an electric decoupling mechanism in Michigan.

15 **Q59. Please elaborate on the impact of Fermi 2 ownership on the Company’s risk**
16 **profile.**

17 A59. Although empirical tests of the effects of the ownership of nuclear generating plants on
18 the cost of capital are inconclusive, the cost of capital is affected by business risk which
19 is the risk remaining after diversifiable risk is removed from total risk.

20 The additional risk of the Fermi 2 Nuclear Generation Plant is likely to be largely
21 diversifiable, but it is also asymmetric. Asymmetric risk refers to a downside risk for
22 which there is no corresponding upside to balance the risk.

80 *Forbes*, “Michigan 2050 Carbon Neutrality Goal Could Be An Economic Engine – If It Avoids A Rush to Gas,” February 9, 2022.

81 Source: Schedule D5.18 Revised

82 Source: Schedule D5.19

1 **Q60. If the risk of Fermi 2 does not affect the cost of capital, what do you recommend**
2 **that the Commission do?**

3 A60. First, the Commission should recognize that the risk of nuclear power plants is
4 asymmetric. The Commission should remove the asymmetric risk if there is an event
5 at the plant because the Company has not been previously compensated through its cost
6 of capital for potential loss. Second, the empirical tests of the effect of nuclear power
7 plants on the cost of capital are likely too “weak” in the sense that is extremely difficult
8 to develop a test likely to detect the effects of nuclear generating assets on the cost of
9 capital for a company. That is because there are so many other factors that affect the
10 cost of capital. For example, nuclear plants are generally owned by holding companies
11 with many other types of assets and are affected by varying regulatory policies. It may
12 well be that nuclear generating plants increase the cost of capital even though empirical
13 tests have not been able to detect it. I regard ownership of Fermi 2 as one more factor
14 indicating that the Company is riskier than the sample on average.

15 **Q61. Did you consider DTE Electric’s capital expenditures relative to those of the**
16 **sample?**

17 A61. Yes. As shown in Schedule D5.18 Revised, DTE Electric’s capital expenditures are
18 higher than of the average company in the Electric Sample. Specifically, the
19 average capital expenditure to net plant is above the average or median of the sample.
20 A higher capital expenditure introduces relatively higher fixed costs, which cannot
21 readily be eliminated should circumstances change. Thus, all else equal, higher
22 capital expenditures increases business risk.

23 **Q62. Can you summarize your assessment of DTE Electric’s business risk relative to**
24 **the sample companies?**

25 A62. In consideration of the factors mentioned above, I believe DTE Electric is of higher
26 than average business risk relative to the sample companies.

1 **VII. COST OF CAPITAL RECOMMENDATION**

2 **Q63. What do you recommend for DTE Electric's cost of equity in this proceeding?**

3 A63. The cost of equity estimates from my analyses were summarized in Figure 13 above
4 and repeated below in Figure 14.

5 **Figure 14: Summary ROE Results**

	Electric Sample	
	Low	High
CAPM / ECAPM	10.8%	11.7%
DCF	9.4%	11.2%
Risk Premium	10.5%	10.5%
Average	10.2%	11.1%

6 * The single-stage DCF average is 10.5% ignoring financial risk.

7 Based on the figures above, it is evident that the current cost of equity is higher than in
8 DTE Electric's last rate case, when a ROE of 9.9 percent was allowed. The average of
9 the low and high estimates results in a range of 10.2 to 11.1 percent, so that the average
10 of the lowest estimates are above the most recently allowed ROE. The midpoint of the
11 range is 10.65 percent. The increase in the cost of equity is predominantly caused by
12 a higher risk-free rate and an increase in the forecasted MRP, while other parameters
13 have remained relatively stable.

14 Based on the data above I recommend that DTE Electric be allowed a ROE of 10.5
15 percent on the 50 percent equity financed rate base. The recommendation is
16 conservative based on my finding that the midpoint of the range I estimate for the
17 comparable sample is above 10.5 percent and DTE Electric has higher business risk
18 than the electric sample group.

19 **Q64. Does this conclude your testimony?**

20 A64. Yes.

21

APPENDIX A: RESUME OF DR. BENTE VILLADSEN

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is assisting entities in the acquisition of regulated utilities regarding issues such the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen served as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
 - Cost of Capital
 - Cost of Service (including prudence)
 - Energy Efficiency, De-coupling and the Impact on Utilities Financials
 - Relationship between regulation and credit worthiness
 - Risk Management
 - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
 - Application of Accounting Standards
 - Disclosure Issues
 - Forensics
 - Credit Issues in the Utility Industry

- Damages and Valuation (incl. international arbitration)
 - Utility valuation
 - Lost Profit for construction, oil&gas, utilities
 - Valuation of construction contract
 - Damages from the choice of inaccurate accounting methodology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, water utilities and barges in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Ohio, Oregon, Virginia and Washington as well as in the provinces of Alberta, Ontario, and Quebec.
- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- On behalf of two taxpayers, Dr. Villadsen has testified on the methodology used to estimate the discount rate for the income approach to property valuation in Utah district court.
- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- On behalf of gas distribution and storage utilities in Quebec, Dr. Villadsen provided expert testimony on the appropriate cost of equity and capital structure for of Énergir, Gazifère, and Intragaz before Régie de l'énergie du Québec.
- For Barbados Light & Power, she provided testimony on the appropriate weighted average cost of capital including the cost of equity, the cost of debt, and capital structure. The matter was heard by the Barbados Fair Trading Commission.
- For potential acquirers of electric, natural gas, and water utilities, Dr. Villadsen has conducted regulatory due diligence in the form of an assessment of the regulatory environment in the jurisdictions at issue including the ability to earn the allowed return and recover costs associated with operations or capital expenditures. Her evaluations also involved an assessment of needed capital expenditures and the recovery of such expenditure through rates or specific

adjustment clauses. Her prior work includes more than 15 US states, the FERC, and several Canadian provinces.

- She has worked on formula rates for transmission companies at FERC; including matters where specific issues such as the determination of the rate base, the treatment of leases, and the recovery of transaction costs have been litigated.
- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.
- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- Dr. Villadsen has advised many acquirers and potential acquirers of regulated utilities regarding the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Her work has pertained to many jurisdiction in the U.S. and Canada including more than 20 states and three provinces as well as the Federal Energy Regulatory Commission. She has worked on electric, natural gas, pipeline, transmission, and water utility acquisitions.
- She has estimated the cost of equity on behalf of entities such as Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, NW Natural, Nicor, Consolidated Edison, Southern California Edison, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the FERC on behalf of electric transmission and natural gas pipelines as well as Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted

a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.

- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- For a FERC-regulated entity, Dr. Villadsen undertook an assessment of the company's classification of specific long-term commitments, leases, regulatory assets, asset retirement obligations, and contributions / distributions to owners in the company's FERC Form 1.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities,

transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.

- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.
- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.

- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.

- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 14 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.
- For an electric utility, Dr. Villadsen provided guidance regarding the regulatory accounts needed as the utility was separated into separate generation, transmission, and distribution entities with each their accounting records.

Accounting and Corporate Finance

- For an electric utility subject to international arbitration, Dr. Villadsen submitted expert testimony on the application of IFRS as it pertains to receivables, the classification of liabilities and contingencies.
- In international arbitration, she submitted an expert report on IFRS' requirements regarding carve out financials, impairment, the allocation of costs to segments, and disclosure issues.
- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- On behalf of a taxpayer, Dr. Villaden has provided an expert report on the nature of the cost of equity used in regulatory proceedings as well as the interest rate regime in 2014.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs

and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.

- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.

- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.
- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.
- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.
- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

“Risk and Return for Regulated Industries,” (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

“International Rate of Return Methods – Recent Developments,” (with Toby Brown and Andrew W. Thompson), prepared for Energy Networks Australia and submitted to the *Australian Energy Regulator*, September 2022.

“A Review of International Approaches to Regulated Rates of Return,” (with J. Anthony, T. Brown, L. Figurelli, D. Harris, and N. Nguyen) published by the *Australian Energy Regulator*, September 2020.

“Global Impacts and Implications of COVID-19 on Utility Finance,” (with R. Mudge, F. Graves, J. Figueroa, T. Counts, L. Mwalenga, and S. Pant), *The Brattle Group*, July 2020.

“Impact of New Tax Law on Utilities’ Deferred Taxes,” (with Mike Tolleth and Elliott Metzler), *CRRRI 37th Annual Eastern Conference*, June, 2018.

“Implications of the New Tax Law for Regulated Utilities,” *The Brattle Group*, January 2018.

“Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments,” *North American Windpower*, May 2017, pp. 34-37.

“Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies,” (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

“Aurizon Network 2016 Access Undertaking: Aspects of the WACC,” (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

“Report on Gas LDC multiples,” with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

“Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC,” prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

“*Brattle Review of AE Planning Methods and Austin Task Force Report.*” (with Frank C. Graves) September 24, 2014.

Report on “Cost of Capital for Telecom Italia’s Regulated Business” with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* (“AGCOM”), March 2014. *Submitted in Italian.*

“Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century,” (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

“Estimating the Cost of Debt,” (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

“Estimating the Cost of Equity for Regulated Companies,” (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

“Calculating the Equity Risk Premium and the Risk Free Rate,” (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

“Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World,” (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

“Survey of Cost of Capital Practices in Canada,” (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

“Public Sector Discount Rates” (with Frank Graves, Bin Zhou), *Brattle* white paper, September 2011

“FASB Accounting Rules and Implications for Natural Gas Purchase Agreements,” (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

“IFRS and You: How the New Standards Affect Utility Balance Sheets,” (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

“Corporate Pension Plans: New Developments and Litigation,” (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

“Review of Regulatory Cost of Capital Methodologies,” (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

“Building Sustainable Efficiency Businesses: Evaluating Business Models,” (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

“Understanding Debt Imputation Issues,” (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

“Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low,” *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

“The Effect of Debt on the Cost of Equity in a Regulatory Setting,” (with A. Lawrence Kolbe and Michael J. Vilbert, and with “*The Brattle Group*” listed as author), *Edison Electric Institute*, April 2005.

“Communication and Delegation in Collusive Agencies,” *Journal of Accounting and Economics*, Vol. 19, 1995.

“Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services” (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

“Financing Infrastructure Investments in an Era of Deep Uncertainty: In Need of Updating the Regulatory Toolbox – an International Perspective,” webinar sponsored by *Utilitalia*, September 26, 2023.

“Current Issues in Cost of Capital” presented to *EEI Members*, July, 2018-19, 2021-23, Madison, WI.

“The Future of Gas: Options and Regulatory Strategies in a Carbon-Constrained Future,” (with Ahmad Faruqui, Josh Figueroa, Long Lam), Presented to Executive Team at Gas Utility, June 2021.

“FERC’s new ROE methodology for pipelines and electric transmission,” (with Michael J. Vilbert) *UBS Fireside Chat*, June 24, 2020.

“Managing Price Risk for Merchant Renewable Investments,” (with Onur Aydin) *EIA Electricity Pricing Workgroup* (webinar), April 30, 2019.

“Decoupling and its Impact on Cost of Capital” presented to *SURFA Members and Friends*, February 27, 2019.

“Introduction to Capital Structure & Liability Management”, *the American Gas Association/Edison Electric Institute “Introduction and Advanced Public Utility Accounting Courses”*, August 2018-2019, August 2022-2023.

“Issues Cost of Capital,” *the American Gas Association/Edison Electric Institute “Advanced Public Utility Accounting Courses Advanced Public Utility Accounting Course,”* August 2023.

“Lessons from the U.S. and Australia” presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

“Should Regulated Utilities Hedge Fuel Cost and if so, How?” presented at *SURFA’s 49 Financial Forum*, April 20-21, 2017.

“Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers,” (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

“Capital Structure and Liability Management,” *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

“Current Issues in Cost of Capital,” *Edison Electric Institute Advanced Rate School*, July 2013-2017.

“Alternative Regulation and Rate Making Approaches for Water Companies,” *Society of Depreciation Professionals Annual Conference*, September 2014.

“Capital Investments and Alternative Regulation,” *National Association of Water Companies Annual Policy Forum*, December 2013.

“Accounting for Power Plant,” *SNL’s Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

“GAAP / IFRS Convergence,” *SNL’s Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

“International Innovations in Rate of Return Determination,” *Society of Utility Financial and Regulatory Analysts’ Financial Forum*, April 2012.

“Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics,” 1.5 day seminar, EUCI, Atlanta, May 2012.

“Cost of Capital Working Group Eforum,” *Edison Electric Institute webinar*, April 2012.

“Issues Facing the Global Water Utility Industry” Presented to Sensus’ Executive Retreat, Raleigh, NC, July 2010.

“Regulatory Issues from GAAP to IFRS,” *NASUCA 2009 Annual Meeting*, Chicago, November 2009.

“Subprime Mortgage-Related Litigation: What to Look for and Where to Look,” *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

“Evaluating Alternative Business / Inventive Models,” (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

“Deferred Income Taxes and IRS’s NOPR: Who should benefit?” *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

“Discussion of ‘Are Performance Measures Other Than Price Important to CEO Incentives?’” *Annual Meeting of the American Accounting Association*, 2000.

“Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach,” (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

TESTIMONY

Affidavit on the Cost of Capital Mechanism on behalf of Pacific Gas & Electric Company, San Diego Gas & Electric, Southern California Gas, and Southern California Edison before the *California Public Utilities Commission*, Application 22-04-008 and related matters, January 2024.

Direct testimony on the cost of equity on behalf of DTE Gas before the *Michigan Public Service Commission*, Case No. U-21291, January 2024.

Direct testimony on the cost of equity on behalf of Orange & Rockland Utilities before the *New York Public Service Commission* (with Josh Figueroa), Case No. 24-E-0060, January 2024.

Direct testimony on the cost of equity on behalf of Northern Border Pipeline Company before the *Federal Energy Regulatory Commission*, Docket No. RP-24-287, December 2023.

Direct testimony on the cost of equity and capital structure on behalf of Anchorage Water Utility and Anchorage Wastewater Utility before the *Regulatory Commission of Alaska*, TA178-122 and TA180-126, December 2023.

Direct and Supplemental Direct testimony on the cost of equity on behalf of Interstate Power and Light before the *Iowa Utilities Board*, Docket No. RPU-2023-0003, October 2023, January 2024.

Direct prepared testimony on the cost of equity on behalf of GTN before the *Federal Energy Regulatory Commission*, Docket No. RP23-1099, September 2023.

Rehearing testimony, Rebuttal Rehearing testimony and hearing appearance on fixed ROE for advanced ratemaking on behalf of Interstate Power and Light before the *Iowa Utilities Board*, Docket No. RPU-2021-0003, July 2023, August 2023.

Expert report on IFRS accounting and forensics in the matter of an *arbitration in London, UK*, under the Arbitration Act 1996, at the instruction Allen & Overy (with Richard Caldwell), June 2023.

Rebuttal Testimony on decoupling in general rate case on behalf of California-American Water Company before the *California Public Utilities Commission*, A.22-07-001, May 2023.

Reply Evidence and Hearing Appearance on cost of equity, capital structure and formula approach behalf of ATCO Utilities, FortisAlberta, and Apex on Cost of Capital before the *Alberta Utilities Commission*, Proceeding 27084, February 2023, April 2023, May 2023.

Direct, Rebuttal and Surrebuttal Testimony on behalf of Portland General Electric on Cost of Capital before the *Public Utility Commission of Oregon*, UE-416, February, July, September 2023.

Direct and Rebuttal Testimony on behalf of DTE Electric on Cost of Capital before the *Michigan Public Service Commission*, Docket No. U-21297, February 2023, July 2023.

Direct Testimony, Rebuttal Testimony and Surrebuttal Testimony on behalf of Northern Illinois Gas Company (Nicor) on Cost of Capital before the *Illinois Commerce Commission*, Docket No. 23-0066, January 2023, May 2023, July 2023.

Direct and Rebuttal Testimony on behalf of Consolidated Edison's Steam Utility on Cost of Capital before the *New York Public Service Commission*, Docket No. 22-S-0659, November 2022, April 2023.

Direct and Rebuttal Testimony on Cost of Capital on behalf of Virginia Natural Gas before the *Virginia State Corporation Commission*, Docket No. 2022-00052, August 2022, May 2023.

Direct and Rebuttal Testimony on 2023 Cost of Capital on behalf of Southern California Edison before the *California Public Utilities Commission*, Application A.22-04-009 (U-338), April 2022, August 2022.

Written Evidence on Cost of Equity on behalf of ATCO, APEX, and Fortis Alberta before the *Alberta Utilities Commission*, Proceeding No. 27084, February 2022.

Prepared Direct Testimony on Cost of Equity on behalf of ANR Pipeline before the *Federal Energy Regulatory Commission*, Docket No. RP22-501-000, January 2022.

Direct Testimony and Rebuttal Testimony on Cost of Capital and Capital Structure on behalf of Consolidated Edison Company of New York before *New York Public Service Commission*, Case No. 22-E-0064 and 22-G-0065, January, June 2022.

Opening and Rebuttal Testimony, Hearing appearance on the Cost of Capital Mechanism on behalf of Southern California Edison before the *Public Utilities Commission of California*, Application A.21-08-013, January, February 2022.

Direct Testimony and Rebuttal Testimony on Cost of Equity on behalf of DTE Electric Company before the *Michigan Public Service Commission*, Case No. U-20836, January, June 2022.

Direct and Rebuttal Testimony on the Cost of Equity and Capital Structure on behalf of Anchorage Water and Wastewater Utility before the *Regulatory Commission of Alaska*, TA-172-122 and TA-172-126, December 2021, October 2022.

Direct Testimony on the Cost of Equity on behalf of Northwest Natural before the *Public Utility Commission of Oregon* (with Josh Figueroa), Docket No. UG-435, December 2021

Direct Testimony and Hearing Appearance on Cost of Equity and Capital Structure on behalf of Énergir, Gazifère, and Intragaz before *Régie de l'énergie du Québec*, R-4156-2021, November 2021, June 2022.

Direct Testimony, Rebuttal Testimony, and Hearing appearance on Cost of Equity for Advanced Ratemaking on behalf of Interstate Power and Light Company, *Iowa Utilities Board*, RPU-2021-0003, November 2021, June and August 2022.

Expert Report and Hearing appearance on Cost of Equity and the Weighted Average Cost of Capital on behalf of Barbados Light and Power Company, *Barbados Fair Trading Commission*, September 2021, October 2022.

Direct Testimony on California's Cost of Capital Mechanism and Cost of Equity on behalf of Southern California Edison, *California Public Utilities Commission*, Application A.21-08-013, August 2021.

Expert Report on Contingent Liabilities and Materiality under IFRS on behalf of of Norilsk Nickel Mauritius, *LCIA Arbitration* No. 163506, August 2021.

Deposition Testimony re. rate of return and bypass rates on behalf on Southwest Gas Corporation, *Superior Court for the state of Arizona, County of Maricopa*, CV2012-050939, August 2021.

Report on Cost of Capital for Hawaii American Water submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2021-0063, August 2021.

Direct Testimony on Cost of Equity on behalf of Portland General Electric, *Oregon Public Utility Commission*, UE-324, July 2021.

Direct Testimony, Rebuttal Testimony, and Hearing Testimony on Cost of Capital on behalf of California-American Water Company, *California Public Utilities Commission*, Application No. A.21-05-001 et al, May 2021, March 2022, May 2022.

Prefiled Direct Testimony on cost of equity on behalf of Southern Star Central Gas Pipeline, *Federal Energy Regulatory Commission*, Docket RP21-778-000, April 2021.

Direct Testimony re. the prospective excessive earnings test on behalf of Cleveland Electric Illuminating Company and the Toledo Edison Company, *Public Utilities Commission of Ohio*, Case Nos. 20-1034-EL UNC and 20-1476-EL-UNC, March 2021.

Rebuttal Testimony re. the discount rate for property valuation in tax assessment on behalf of Union Pacific Railroad, *Utah District Court*, Case No. 2:18-cv-00630-DAK_DBP (Union Pacific Railroad v. Utah State Tax Commission et al), February 2021.

Direct Testimony and Rebuttal Testimony on cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, U-20940, February and June 2020.

Direct Testimony on the cost of equity on behalf of Orange & Rockland Utilities submitted to the *New York Department of Public Service*, Case No. 21-E-0074, January 2021.

Direct Testimony, Rebuttal Testimony, and Surrebuttal Testimony on the cost of equity on behalf of Nicor Gas submitted to the *Illinois Commerce Commission*, Docket No. 21-0098, January 2021, June 2021, July 2021.

Direct Testimony and Hearing Testimony on the cost of equity and capital structure on behalf of Anchorage Water and Wastewater Utility submitted to the *Regulatory Commission of Alaska*, Matters TA168-122 and 168-126, December 2020, January 2022.

Direct Testimony on the cost of equity on behalf of NW Natural submitted to the *Washington Transportation and Utilities Commission*, Docket No. UG-200994, December 2020.

Written Evidence in Review and Variance of Decision 22570-D01-2018 Stage 2 (AltaGas' capital structure) (joint with Paul R. Carpenter) on behalf of AltaGas Utilities Inc. Filed with the *Alberta Utilities Commission*, Proceeding 25031, January 2020.

Written Evidence on Cost of Equity and Capital Structure on behalf of ATCO, AltaGas and FortisAlberta in 2021-2022 Generic Cost of Capital Proceeding. Filed with the *Alberta Utilities Commission*, Proceeding No. 24110, January 2020.

Report on the Return Margin for the Alberta Bottle Depots on behalf of the Alberta Beverage Container Recycling Corporation, February 2020.

Verified Statement and Reply Verified Statement regarding Revisions to the Board's Methodology for Determining the Railroad Industry's Cost of Capital on behalf of the American Association of Railroads before the *Surface Transportation Board*, Docket No. EP 664 (Sub-No. 4), January, February 2020.

Affidavit regarding the creation of a regulatory asset for earthquake related costs on behalf of Anchorage Water and Wastewater submitted to the *Regulatory Commission of Alaska*, December 2019.

Expert Report and Hearing Appearance on Going Concern and Impairment, *American Arbitration Association*: International Engineering & Construction S.A., Greenville Oil & Gas Co. Ltd and GE Oil & Gas, Inc., November, December 2019.

Direct Testimony and Rebuttal Testimony on the cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20642, November 2019.

Expert Report, Reply Report and Hearing Testimony on IFRS Issues and Forensics. *SIAC Arbitration* No. 44 of 2018, October 2019, September 2021, September 2022.

Expert Report, Reply Report and Hearing Appearance on IFRS issues. *ICC Arbitration* No. 23896/GSS, September 2019, September and November 2020.

Direct Testimony on the cost of debt and equity capital as well as capital structure on behalf of Young Brothers, LLC. submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2019-0117, September 2019.

Direct Testimony on Cost of Equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20940, February 2021.

Expert Report on discount rates in property tax matter for Union Pacific Company in *Union Pacific Railroad Co. v. Utah State Tax Comm'n, et. al.*, Case No. 2:18-cv-00630-DAK-DBP, Utah August 2019.

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APPENDIX B; Technical Appendix to the Direct Testimony of Bente Villadsen

This technical appendix contains methodological details related to my implementations of the DCF and CAPM / ECAPM models. It also contains a discussion of both the basic finance principles and the specific standard formulations of the financial leverage adjustments employed to determine the cost of equity for a company with the level of financial risk inherent in DTE Electric's requested regulatory capital structure.

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I. DCF Models

A. DCF ESTIMATION OF COST OF EQUITY

The DCF method for estimating the cost of equity capital assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \quad (1)$$

where P_0 is the current market price of the stock; D_t is the dividend cash flow expected at the end of period t ; r is the cost of equity capital; and T is the last period in which a dividend cash flow is to be received. The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received. Since the current market price is known, it is possible to infer the cost of equity that corresponds to that price and a forecasted pattern of expected future dividends. In terms of Equation (1), if P_0 is known and $D_1, D_2, \dots, D_T$ are estimated, an analyst can “solve for” the cost of equity capital r .

B. DETAILS OF THE DCF MODEL

Perhaps the most widely known and used application of the DCF method assumes that the expected rate of dividend growth remains constant forever. In the so-called Gordon Growth Model, the relationship expressed in Equation (1) is such that the present value equation can be rearranged algebraically into a formula for estimating the cost of equity. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by

$$P_0 = \frac{D_1}{r - g} \quad (2)$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the market price and the cost of capital, as before. Equation (2) is a simplified version of Equation (1) that can be solved algebraically to yield the well-known “DCF formula” for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1 + g)}{P_0} + g \quad (3)$$

There are other versions of the DCF model that relax this restrictive assumption and posit a more complex or nuanced pattern of expected future dividend payments. For example, if there is reason to believe that investors do *not* expect a company's dividends to grow at a steady rate forever, but rather have different growth rate expectations in the near term (e.g., over the next five or ten years), compared to the distant future (e.g., a period *starting* ten years from the present moment), a “multi-stage” growth pattern can be modeled in the present value formula (Equation (1)).

1. Dividends, Cash Flows, and Share Repurchases

In addition to the DCF model described above, there are many alternative formulations. Notable among these are versions of the model that use cash flows rather than dividends in the present value formula (Equation (1)).¹

Because investors are interested in cash flow, it is technically important to capture *all* cash flows that are distributed to shareholders when estimating the cost of equity using the DCF method. In some circumstances, investors may expect to receive cash in forms other than dividends. An important example concerns the fact that many companies distribute cash to shareholders through share buybacks in addition to dividends. To the extent such repurchases are expected by investors, but not captured in the forecasted pattern of future dividends; a dividend-based implementation of the DCF model will underestimate the cost of equity.

Similarly, if investors have reason to suspect that a company's dividend payments will not reflect a full distribution of its available cash free cash flows in the period they were generated, it may be appropriate replace the forecasted dividends with estimated free cash flows to equity in the present value formula (Equation (1)). Focusing on *available* cash rather than that actually distributed in the form of dividends can help account for instances when near-term investing and financing activities (e.g., capital expenditures or asset sales, debt issuances or retirements, or share repurchases) may cause dividend growth patterns to diverge from growth in earnings.

¹ For an example in a regulatory context, the U.S. Surface Transportation Board uses a cash flow based model with three stages to estimate the cost of equity for the railroads. See Surface Transportation Board Decision, “STB Ex Parte No. 664 (Sub-No. 1),” Decided January 23, 2009. Confirmed in EP-664 (Sub-No. 2), October 31, 2016 and EP 664 (Sub-No. 4), June 23, 2020.

Many utility companies such as those included in my proxy group have long histories of paying a dividend. In fact, as mentioned in Section I of this Appendix, one of my standard requirements for inclusion in my proxy group is that a company pays dividends for 5-years without a gap or a dividend cut (on per share basis) in the last six months. Additionally, although some utility companies have engaged in share repurchase programs, the companies in my proxy group do not distribute substantial cash flows by means other than dividends.

C. DCF MODEL INPUTS

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each proxy group company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day, yet is consistent with using current stock prices.

2. Company Specific Growth Rates

a. Analysts' Forecasted Growth Rates

Finding the right growth rate(s) is usually the “hard part” of applying the DCF model, which is sometimes criticized due to what has been called “optimism bias” in the earnings growth rate forecasts of security analysts. Optimism bias is defined as tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. Any optimism bias might be related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts the cost of capital estimates from the DCF model would be too high.

While academic researchers during the 1990s as well as in early 2000s found evidence of analysts' optimism bias, there is some evidence that regulatory reforms have eliminated the issue. A more recent paper by Hovakimina and Saenyasiri (2010) found that recent efforts to curb analysts' incentive to provide optimistic forecasts have worked, so that “the median forecast bias essentially

disappeared.”² Thus, some recent research indicates that the analyst bias may be a problem of the past.

The findings of several academic studies³ show that analyst earnings forecasts turn out to be too optimistic for stocks that are more difficult to value, for instance, stocks of smaller firms, firms with high volatility or turnover, younger firms, or firms whose prospects are uncertain. Coincidentally, stocks with greater analyst disagreement have higher analyst optimism bias—all of these describe companies that are more volatile and/or less transparent—none of which is applicable to the majority of utility companies with wide analyst coverage and information transparency. Consequently, optimism bias is not expected to be an issue for utilities.

b. Sources for Forecasted Growth Rates

For the reasons described above, I rely on analyst forecasts of earnings growth for the company-specific growth rate inputs to my implementations of the single- and multi-stage DCF models. Most companies in my proxy group have coverage from equity analysts reporting to Thomson Reuters IBES, so I use the consensus 3-5 year EPS growth rate provided by that service. I supplement these consensus values with growth rates based on EPS estimates from *Value Line*.⁴

II. CAPM and ECAPM

A. THE CAPITAL ASSET PRICING MODEL (CAPM)

The Capital Asset Pricing Model (CAPM) is a theoretical model stating that the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2 in my Direct Testimony), in which

² A. Hovakimian and E. Saenyasiri, “Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation,” *Financial Analysts Journal*, vol. 66, 2010.

³ These studies include the following: (i) Hribar, P, McInnis, J. “Investor Sentiment and Analysts’ Earnings Forecast Errors,” *Management Science* Vol. 58, No. 2 (February 2012): pp. 293-307; (ii) Scherbina, A. (2004), “Analyst Disagreement, Forecast Bias and Stock Returns,” downloaded from Harvard Business School Working Knowledge: <http://hbswk.hbs.edu/item/5418.html>; and (iii) Michel, J-S., Pandes J.A. (2012), “Are Analysts Really Too Optimistic?” downloaded from <http://www.efmaefm.org>.

⁴ Specifically, I compute the growth rate implied by *Value Line*’s current year EPS estimate and its projected 3-5 year EPS estimate. I then average this in with the IBES consensus estimate as an additional independent estimate, giving it a weight of 1 and weighting the IBES consensus according to the number of analysts who contributed estimates.

the required expected return on an asset is proportional to that asset's risk relative to the market as measured by its "beta". More precisely, the CAPM states that the cost of capital for an investment S (e.g., a particular common stock), is given by the following equation:

$$r_s = r_f + \beta_s \times MRP \quad (4)$$

where r_s is the required return on investment S ;

r_f is the risk-free interest rate;

β_s is the beta risk measure for the investment S ; and

MRP is the market equity risk premium.

The CAPM is based on portfolio theory, and recognizes two fundamental principles of finance: (1) investors seek to minimize the possible variance of their returns for a given level of expected returns (or alternatively, they demand higher *expected* returns when there is greater uncertainty about those returns), and (2) investors can reduce the variability of their returns by diversifying—constructing portfolios of many assets that do not all go up or down at the same time or to the same degree. Under the assumptions of the CAPM, the market participants will construct portfolios of risky investments that minimize risk for a given return so that the aggregate holdings of all investors represent the "market portfolio." The risk-return trade-off faced by investors then concerns their exposure to the risk inherent in the market portfolio, as they weight their investment capital between the portfolio of risky assets and the risk-free asset.

Because of the effects of diversification, the relevant measure of risk for an individual security is its *contribution* to the risk of the market portfolio. Therefore, beta (β) is defined to capture the sensitivity of the security's returns to the market's returns. Formally,

$$\beta_s = \frac{\text{covariance}(r_s, R_m)}{\text{variance}(R_m)} \quad (5)$$

where R_m is the return on the market portfolio.

Beta is usually calculated by statistically comparing (using regression analysis) the excess (positive or negative) of the return on the individual security over the government bond rate with the excess of the return on a market index such as the S&P 500 over a government bond rate.

The basic idea behind beta is the risk that cannot be diversified away in large portfolios is what matters to investors. Beta is a measure of the risks that *cannot* be eliminated by diversification. It is this non-diversifiable risk, or "systematic risk", for which investors require compensation in the

form of higher expected returns. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk; its returns vary to the same degree as those on the market as a whole. According to the CAPM, the required return demanded by investors (i.e., the cost of equity) for investing in that stock will match the expected return on the market as a whole. Similarly, stocks with betas above 1.0 have more than average risk, and so have a cost of equity greater than the expected market return; those with betas below 1.0 have less than average risk, and are expected to earn lower than market levels of return.

B. INPUTS TO THE CAPM

1. The Risk-free Interest Rate

The precise meaning of a “risk-free” asset according to the finance theory underlying the CAPM is an investment whose return is guaranteed, with no possibility that it will vary around its expected value in response to the movements of the broader market. (Equivalently, the CAPM beta of a risk-free asset is zero). In developed economies like the U.S., government debt is generally considered to have no default risk. In this sense they are “risk-free”; however, unless they are held to maturity, the rate of return on government bonds may in fact vary around their stated or expected yields.⁵

The theoretical CAPM is a single period model, meaning that it posits a relationship between risk and return over a single “holding period” of an investment. Because investors can rebalance their portfolios over short horizons, many academic studies and practical applications of the CAPM use the short-term government bond as the measure of the risk-free rate of return. However, regulators frequently use a version based on a measure of the long-term risk-free rate; e.g., a long-term government bond. I rely on the 20-year Treasury bond as a measure of the risk-free asset in this proceeding.⁶ I use the term “risk-free rate” as describing the yield on the 20-year Treasury bond.

However, I do not believe the *current* yield on long-term Treasury bonds is a good estimate for the risk-free rate that will prevail over the time period relevant to this proceeding. Instead, I believe it is more important to use the yield that is expected to prevail during the rate period.⁷ For this reason I average Blue Chip’s forecast of 3.9% and 3.7% for the yield on a 10-year Treasury bond for 2024 and 2025, respectively.⁸ I adjust this average (3.80%) upward by 50 basis points, which

⁵ This is due to interest rate fluctuations that can change the market value of previously issued debt in relation to the yield on new issuances

⁶ The use of a 20-year government bond is consistent with the measurement of the Ibbotson MRP and permits us to use a series that has been in consistent circulation since the 1990’s (the 30-year government bond was not issued from 2002 to 2006).

⁷ At the end of the technical appendix, I provide a version of the CAPM results which use current bond yields.

⁸ Wolters Kluwer, Blue Chip Economic Indicators, vol. 49, January 10, 2024, pp. 2-3.

is my estimate of the maturity premium for the 20-year over the 10-year Treasury bond. This provides me with an estimate of the risk free rate of 4.30%.

2. The Market Equity Risk Premium

a. Historical Average Market Risk Premium

Like the cost of capital itself, the market risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.

One commonly use method for estimating the MRP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period. When such a calculation is performed using the traditional industry standard Ibbotson data, the result is an arithmetic average of the annual observed premiums of U.S. stock market returns over income returns on long-term (approximate average maturity of 20-years) U.S. Treasury bonds from 1926 to the present is 7.17%.⁹

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current level on market indexes; for the U.S. Bloomberg performs a multi-stage DCF using dividend-paying stocks in the S&P 500 to infer the expected market return.

When calculated relative to 20-year Treasury bond yields, Bloomberg's estimate of the forward-looking market-implied MRP over the month leading up to my analysis was 6.37% over the 20-year Treasury bond yield.¹⁰ I note that this is a conservative estimate as the FERC-relied upon methodology to determine the MRP as of December 31, 2023 results in an MRP 7.87% and 7.90% as shown in Schedule D5.17. I therefore consider the historical estimate of 7.17 percent to be more reasonable.

⁹ Kroll Cost of Capital Navigator, U.S. Cost of Capital Module, accessed January 5, 2024, value as of December 31, 2022.

¹⁰ Bloomberg, as of December 31, 2024.

C. THE EMPIRICAL CAPM

1. Description of the ECAPM

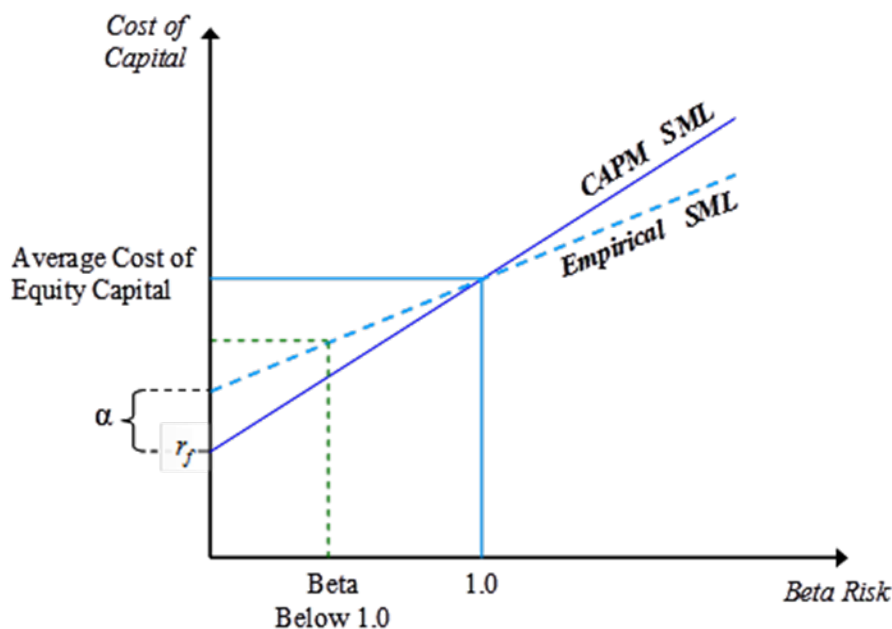
Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

The Empirical CAPM (ECAPM) makes use of these empirical findings. It estimates the cost of capital with the equation,

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \quad (6)$$

where α is the “alpha” adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (4)). The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line, which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure B-2
The Empirical Security Market Line



2. Academic Evidence on the Alpha Term in the ECAPM

Figure B-3 below summarizes the empirical results of tests of the CAPM, including their estimates of the “alpha” parameter necessary to improve the accuracy of the CAPM’s predictions of realized returns.

Figure B-3

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM^{*}

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993) ¹	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972) ²	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992) ³	7.32%	1941-1990
Fama and French (2004) ⁴	N/A	
Litzenberger and Ramaswamy (1979) ⁵	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995) ⁶	4.6%	1936-1990

^{*} The figures reported in this table are for the longest estimation period available and, when applicable, use the authors’ recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

¹Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.

²Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.

³Calculated using Ibbotson’s data for the 30-day treasury yield.

⁴The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.

⁵Relies on Lizenberger and Ramaswamy’s before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.

⁶Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:

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III. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.¹¹ It may be tempting to simply estimate the cost of equity capital for each of the proxy companies (using one of the above approaches) and average them. After-all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders. The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. As a consequence, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.¹²

A. THE EFFECT OF FINANCIAL LEVERAGE ON THE COST OF EQUITY

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure B-4 and Figure B-5 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either \$5 or \$15 and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is $\frac{1}{2}$).

¹¹ This is also a common valuation problem in general business contexts.

¹² I refer to this effect in terms of *financial risk* because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the *business risk* associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

Figure B-4: All Equity Capital Structure

	Asset Cash Flow	Debt Service	Equity Dividend	ROE
$\swarrow \frac{1}{2}$	\$15	\$0	\$15	$15/100 = 15\%$
$\searrow \frac{1}{2}$	\$5	\$0	\$5	$5/100 = 5\%$
				$E(ROE) = 10\%$
				$\sigma(ROE) = 5\%$

Figure B-5: 50/50 Capital Structure

	Asset cash flow	Debt Service	Equity Dividend	ROE
$\swarrow \frac{1}{2}$	\$15	\$2.50	\$12.50	$12.50/50 = 25\%$
$\searrow \frac{1}{2}$	\$5	\$2.50	\$2.50	$2.50/50 = 5\%$
				$E(ROE) = 15\%$
				$\sigma(ROE) = 10\%$

In the figures, $E(ROE)$ indicates the mean return and $\sigma(ROE)$ represents the standard deviation. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The “magic” of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. METHODS TO ACCOUNT FOR FINANCIAL RISK

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a proxy group are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.¹³ The expected return to the underlying asset is therefore equal to the value weighted

¹³ Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (7), where P refers to the market value of preferred equity, r_p is the cost of preferred equity and $V = E + D + P$. In my analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

average of the expected returns to equity and debt holders – which is the overall cost of capital (r^*), or the expected return on the assets of the firm as a whole.¹⁴

$$r^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \quad (7)$$

where r_D is the market cost of debt,
 r_E is the market cost of equity,
 τ_c is the corporate income tax rate,
 D is the market value of the firm's debt,
 E is the market value of the firm's equity, and
 $V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.¹⁵

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.¹⁶ Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the

¹⁴ As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's *assets* independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (7) represents the overall weighted average cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

¹⁵ Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

¹⁶ Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,¹⁷ showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,¹⁸ the latter can still be shown to be constant across a broad range of capital structures.¹⁹

This reasoning suggests that one could compute the overall cost of capital for each of the proxy companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then rearrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.²⁰

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

¹⁷ Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

¹⁸ When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

¹⁹ This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

²⁰ Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:²¹

$$V = V_U + PV(ITS) \quad (8)$$

where $V = E + D$ is the total value of the firm as in Equation (7),

V_U is the “unlevered” value of the firm—its value if financed entirely by equity

$PV(ITS)$ represents the present value of the interest tax shields associated with debt

For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \quad (9)$$

where r_U is the “unlevered cost of capital”—the required return on assets if the firm’s assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (7).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the “levered” equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm’s actual market value capital structure) and the “unlevered” beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \quad (10)$$

where β_D is the beta on the firm’s debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm’s assets. Since the beta on

²¹ This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., “Levered and Unlevered Beta,” IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., “The Effect of the Firm’s Capital Structure on the Systematic Risk of Common Stock,” *Journal of Finance*, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, “Reformulating Tax Shield Valuation: A Note,” *Journal of Finance*, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, “Risk-Adjusted Discount Rates Extensions from the Average-Risk Case,” *Journal of Financial Research*, Fall 1985, pp. 237-244; Fernandez, P., “The Value of Tax Shields Depends Only on the Net Increases of Debt,” IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of *levered* equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \quad (11)$$

Unlike Equation (10), Equation (11) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U . In principal, Equation (10) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting my CAPM estimates for financial risk, and consider the results as sensitivities in my analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (10), or Equation (11). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A-rated debt and a beta of 0.10 for BBB rated debt.²²

Once a decision on debt betas is made, the levered equity beta of each proxy company can be computed (in this case by Value Line) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the proxy companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the proxy companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity for the regulated target company, this estimate of unlevered beta can be "re-levered" to the regulated company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

²² Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition*. 2011 Prentice Hall, p. 389.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development²³—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

²³ Hamada, R.S., “The Effect of the Firm’s Capital Structure on the Systematic Risk of Common Stock”, *The Journal of Finance*, 27(2), 1971, pp. 435-452.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

BENTE VILLADSEN

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1 **I. Introduction & Purpose**

2 **Q1. Please state your name and business address.**

3 A1. My name is Dr. Bente Villadsen (she/her/hers). My business address is One
4 Beacon Street, Suite 2600, Boston, Massachusetts, 02108.

5 **Q2. Are you the same Dr. Bente Villadsen who previously filed direct testimony**
6 **in this proceeding?**

7 A2. Yes.

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

9 A3. I have been asked by DTE Electric Company (“DTE Electric” or the
10 “Company”) to review and respond to the testimonies of the following
11 witnesses regarding the cost of equity and return on equity (“ROE”)
12 recommendations:

- 13 • Joseph Ufolla (Ufolla Testimony) on behalf of Michigan Public Service
14 Commission (“Commission” or “MPSC”) Staff (“Staff”),
- 15 • Sebastian Coppola (Coppola Testimony) on behalf of the Attorney
16 General’s (“AG”) office,
- 17 • Christopher Walters (Walters Testimony) on behalf of the Association
18 of Businesses Advocating Tariff Equity (“ABATE”),
- 19 • Matthew J. Bandyk (Bandyk Testimony) on behalf of Citizens Utility
20 Board of Michigan (“CUB”) and Michigan Environmental Council
21 (“MEC”) (collectively, “CUB-MEC”),
- 22 • Lisa A. Perry (Perry Testimony) on behalf of Walmart, Inc.
- 23 • Melissa Stults (Stults Testimony) on behalf of the City of Ann Arbor
24 (“AA”).

25 I only respond to those part of the testimonies mentioned above that discuss
26 cost of capital or ROE issues.

1 **Q4. Is there anything in MPSC Staff and Intervenor testimonies that caused**
2 **you to change your recommendations regarding DTE Electric's cost of**
3 **capital?**

4 A4. No. Having reviewed MPSC Staff's as well as Messrs. Walters, Coppola,
5 Bandyk, Ms. Perry and Dr. Stults (collectively, the "Intervenors") testimonies,
6 and having considered recent changes in economic conditions, I continue to find
7 that my original recommendation for the ROE of 10.50 percent on 50 percent
8 equity capital structure is reasonable.

9 **Q5. Please provide an overview of your rebuttal testimony.**

10 A5. I respond to the Intervenors' proposed ROEs and to their criticisms of my ROE
11 estimate of 10.50 percent percent from my Direct Testimony. First, I discuss
12 whether Intervenors' respective recommended ROE is appropriate given
13 today's financial markets, the status of electric utilities, and DTE Electric's
14 business risk. Second, I address Intervenors' respective approaches to
15 determining an appropriate ROE. Third, I address misunderstandings and
16 criticisms of my considerations of financial leverage. This adjustment is
17 necessary and well accepted by finance textbooks, academics, as well as used
18 in prior rate cases, to estimate the cost of equity for sample firms that have a
19 mixed capital structure. Fourth, I respond directly to other criticisms of my
20 comparable group or ROE methods – the use of the Empirical Capital Asset
21 Pricing Model ("ECAPM"), Discounted Cash Flow ("DCF") and market risk
22 premium ("MRP") approach. I continue to opine that 10.50 percent, as stated in
23 my Direct Testimony, is the ROE that DTE Electric should be allowed an
24 opportunity to earn.

25 **Q6. Are you sponsoring any exhibits as part of your rebuttal testimony?**

26 A6. Yes. I am sponsoring the following exhibits:

- 27 • Exhibit A-39, Schedule DD1: Comparison of ROE Witness Samples
- 28 • Exhibit A-39, Schedule DD2: Walters CAPM
- 29 • Exhibit A-39, Schedule DD3: Walters DCF

- 1 • Exhibit A-39, Schedule DD4: Walters Summary
- 2 • Exhibit A-39, Schedule DD5: Coppola DCF
- 3 • Exhibit A-39, Schedule DD6: Coppola Summary
- 4 • Exhibit A-39, Schedule DD7: Ufolla Summary
- 5 • Exhibit A-39, Schedule DD8: DTE Energy Capital Structure
- 6 • Exhibit A-39, Schedule DD9: Bandyk DCF
- 7 • Exhibit A-39, Schedule DD10: Change of ROE Recommendation Since U-
- 8 21297
- 9 • Exhibit A-39, Schedule DD11: Impact of Financial Leverage
- 10 • Exhibit A-39, Schedule DD12: Integrated Electric ROEs in 2024

11 II. Summary Recommendations and Responses

12 **Q7. Please summarize the parties' respective recommendations for DTE**
13 **Electric's authorized ROE and equity percentage.**

14 **A7.** Table 1 below summarizes the parties' respective recommendations for DTE
15 Electric's authorized ROE and equity percentage.

16 **TABLE 1: SUMMARY OF RECOMMENDATIONS¹**

	Recommended ROE	Low end for ROE	High end for ROE
Company, Villadsen	10.50%	10.25%	11.0%
Staff, Ufolla	9.90%	9.30%	10.30%
AG, Coppola ¹⁾	9.85%	9.26%	10.57%
ABATE, Walters	9.60%	9.20%	10.0%
CUB-MEC, Bandyk ²⁾	9.30%	8.59%	9.90%
Walmart, Perry	< 10.50%		
AA, Stults	< 9.90%		

17 ¹⁾ Coppola's range displays range of the estimates used for his recommendation.

18 ²⁾ Bandyk's range displays range considered for his recommendation.

¹ Villadsen Direct, p. 6; Ufolla Testimony, p. 8; Coppola Testimony, p. 100 and AG-27; Walters Testimony, p. 3; Bandyk Testimony, p. 23 and Workpaper Bandyk workpapers U-21534; neither the Perry Testimony nor the Stults Testimony has an explicit recommendation.

Of note, the Ufolla Testimony and the Coppola Testimony recommended no changes to the capital structure submitted by DTE Electric, while the Walters Testimony incorrectly claimed the Company seeks a 53.5 percent equity percentage, but ultimately did not appear to make an alternative recommendation.² The Bandyk Testimony, the Perry Testimony, and the Stults Testimony did not specifically address capital structure.

Q8. What issues from the Staff's and Intervenor's direct testimony are you addressing in your rebuttal testimony?

A8. Specifically, I am addressing the following issues:

- Whether the recommended ROEs of 9.90 percent (Ufolla Testimony), 9.85 percent (Coppola Testimony), 9.60 percent (Walters Testimony), or 9.30 percent (Bandyk Testimony) are reasonable in today's financial environment given DTE Electric's business risks.
- Whether the proposal to lower the ROE from the currently allowed 9.90 percent as suggested by Dr. Stults is reasonable and whether Ms. Perry's views on the currently allowed ROEs across the U.S. is reasonable.
- The inputs and specifications of the models relied upon by Mr. Ufolla, Mr. Coppola, Mr. Walters, and Mr. Bandyk as well as the approach taken by Ms. Perry and Dr. Stults.
- Staff and Intervenor's critique of my Capital Asset Pricing Model ("CAPM"), DCF, and risk premium implementation.
- The importance of considering financial leverage.
- DTE Electric's business risk considerations.

² Walters Testimony, p. 25. See Rebuttal Testimony of Company Witness Lepczyk for additional discussion of ABATE Witness Walters' capital structure testimony, including re-confirmation of the Company's requested 50% equity percentage.

1 **Q9. What are your key conclusions?**

2 A9. Based on my review and analysis of MPSC Staff and Intervenors testimony, I
3 find that their recommended ROEs are too low in today's financial environment
4 and that my recommened ROE of 10.50 percent remains valid. I also find that
5 several missteps and improper inputs to the models downward biases the results.
6 To summarize:

- 7 • Indications are that the cost of equity has increased since DTE Electric's
8 last rate case (Case No. U-21297) and experts who submitted testimony in
9 both U-21297 and this matter appear to agree as Mr. Ufolla, Mr. Coppola,
10 and Mr. Walters all have inceased their ROE recommendation.³

11 **Q10. Please summarize your testimony.**

12 A10. Having reviewed the testimony of MPSC Staff and Intervenors, I find the
13 following:

- 14 • MSPC Staff's and Intervenors' recommendations are too low in
15 today's economic and financial environment. When viewed in
16 the proper context and modified to properly reflect current
17 inputs and best practices, the results are supportive of DTE
18 Electric's requested ROE of 10.50 percent.
- 19 • The request for an equity percentage of 50 percent is below that
20 recently awarded to electric utilities and reasonable.
- 21 • Contrary to Messrs. Ufolla, Walters, and Coppola's statements,
22 a consideration of financial leverage is merited from both a
23 financial economics and regulatory perspective. Ignoring
24 financial leverage downwardly biases the results by at least 50
25 basis points.

³ Comparing the recommendations in U-21297 to those in this docket, U-21534: Mr. Ufolla 9.80% versus 9.90% in this instant case, Mr. Coppola 9.80% versus 9.85% in this instant case, and Mr. Walters 9.55% versus 9.60% in this instant case. Mr. Bandyk did not submit testimony in U-21297.

1 Regarding the implementation of the cost of equity estimation models, I note
2 the following key flaws in MSPC Staff's and Intervenors' approaches:

- 3 • Assigning an excessive weight to the DCF results, as does Mr.
4 Coppola, downward biases his estimated cost of equity.
- 5 • For the CAPM:
 - 6 ○ The use of an outdated and short-term Market Risk Premium
7 ("MRP"), as does Mr. Bandyk, downward biases his estimated
8 cost of equity.
 - 9 ○ Relying on historical betas, as Mr. Walters does, fails to
10 recognize that the systematic risk of utilities has changed during
11 the last decade.
 - 12 ○ The use of Kroll's recommended MRP without using the
13 recommended risk-free rate or using surveys, as does Mr.
14 Bandyk, downward biases the CAPM results.
- 15 • For the DCF Model:
 - 16 ○ Considering only the multi-stage DCF leads to a downward bias
17 in the estimation results from Mr. Bandyk.
 - 18 ○ The sustainable growth model as implemented by Mr. Walters
19 is internally inconsistent in that the inputs used for the ROE
20 differ substantially from the calculated ROE.
 - 21 ○ Reliance on negative growth rates in the DCF model, like Mr.
22 Ufolla does, leads to a downward bias in the cost of equity
23 estimated using the DCF model.
- 24 • For the Risk Premium Model:
 - 25 ○ Using a regression approach to determine the inherent risk
26 premium in allowed ROEs takes into account the relationship
27 between the risk premium and interest rates. The calculation of

simple averages, which Messrs. Ufolla, Walters, and Coppola
rely on, fails to consider this relationship.

- Financial models are needed to estimate the current cost of equity,
so testimonies without such analysis like Dr. Stults and Ms. Perry
should not be considered.

In Sections II.B, II.C, II.D and II.E I discuss these issues in more detail and
demonstrate the impact of some key implementation issues. Table 2 below
summarizes the impact of modifying these implementation issues.

**TABLE 2: SUMMARY OF MODIFICATIONS TO STAFF'S AND INTERVENORS'
MODEL IMPLEMENTATIONS (AVERAGES ONLY)⁴**

	Staff Ufolla	AG Coppola	ABATE Walters	CUB-MEC Bandyk
DCF				
As filed	9.78%	9.26%	9.45%	8.66%
Modified	9.76%	9.43%	9.63%	9.61 %
CAPM				
As filed	10.23%	10.57%	10.39%	8.53%
Modified	10.38%	10.57%	10.67%	10.33%
Risk Premium				
As filed	(8.63% to 10.05%)	10.10%	9.95% - 10.27%	n/a
Modified	10.05%	10.10%	10.11%	n/a
Recommendation				
As filed	9.90%	9.85%	9.60%	9.30%
Modified ¹⁾	10.06%	10.04% (rounding to 10.09%)	10.14%	9.97%

1) Simple average of the Modified results for the DCF, CAPM, and Risk
Premium.

⁴ As filed results from Ufolla Testimony, p. 21 noting that the 8.63% and 10.05% are his lowest and highest number – not a recommendation; Coppola Testimony, Exhibit AG-27; and Walters Testimony, pp. 37, 42 and 52.

I note that once proper inputs and implementation are taken into account the range of estimates is relatively narrow from about 10.0 percent to about 10.15 percent before any consideration of financial leverage. As financial leverage account for at least 50 basis points, the data clearly supports the Company's request for a ROE of 10.50 percent.

II.A. Today's Financial Environment Requires an ROE Higher than that Proposed by MPSC Staff and Intervenors

Q11. How would you describe MPSC Staff and Intervenors' recommended ROEs?

A11. The ROEs recommended by MPSC Staff and Intervenors are too low, as they all recommend that the authorized ROE remains the same (Ufolla) or decrease (Coppola, Walters, Bandyk, Stults), while indications are that the cost of equity has increased since DTE Electric's cost of equity was last assessed.⁵ Messrs. Ufolla, Coppola, and Walters all recognize that and recommend a slightly higher ROE now than they did in the Company's last rate case, Case No. U-21297.⁶

Looking to the yield on the 20-year Treasury bond in the month immediately preceding the filing in the instant case, the last rate case and as of the present date, I note that this yield was 3.81 percent in January 2023 (shortly before U-21297 was filed), 4.04 percent in June 2023 (at the time Staff and Intervenors filed testimony in U-21297), and Mr. Walters refers to the current (July 2024) yield as 4.57 percent.⁷ Thus, the 20-year Treasury bond yield is higher now

⁵ Case No. U-21297 filed February 2023 with intervener/Staff rebuttal in June 2023 and a decision in December 2023 (Order in U-21297, pp. 1, 3).

⁶ Comparing the recommendations in Table 1 to those submitted U-21297 (e.g., Figure 1 in Rebuttal Testimony of Bente Villadsen, Case No. U-21297, p. 5). See Exhibit A-39, Schedule DD10 for details.

⁷ Using monthly data from the Federal Reserve, St. Louis and the Walters Testimony pp. 45-46 calculates the July 2024 yield as 4.57%: [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/)

1 than during the Company's last rate case. Similarly, the yield on 10- and 30-
2 year Treasury bonds have increased by approximately 50 basis points since
3 Staff and Intervenor filed testimony in Case No. U-21297 on June 13, 2023
4 and by more than that since DTE Electric filed direct testimony in that
5 proceeding on February 10, 2023. Similarly, the Bloomberg forecasted MRP
6 is higher than that Bloomberg calculated in U-21297, while the historical MRP
7 has declined slightly.⁸ These are indications of a higher cost of capital.

8 Of particular note, the ROE recommendation of Mr. Bandyk is below that
9 allowed for any integrated electric utility in 2024 except Public Service New
10 Mexico, which is a unique decision that is under appeal at the New Mexico
11 Supreme Court.⁹ The recommendation is also well below that of other Staff and
12 Intervenor witnesses indicating that he relies on outlier inputs or models. In
13 this case, the low estimates are predominantly caused by Mr. Bandyk exclusive
14 reliance on the multi-stage DCF and an unreliable low MRP in his CAPM.

15 In addition, I note that the peer group simple average of Mr. Coppola's cost of
16 equity estimates from the DCF model, the CAPM, and the risk premium model
17 is 10.04 percent prior to taking Mr. Coppola's rounding into account and 10.09
18 percent once his rounding suggestion is considered.¹⁰

19 Further, while Mr. Walters displays various ROE ranges in Figure CCW-5, they
20 reflect a substantial bias towards the low-end of his estimated range (9.20
21 percent to 10.20 percent) in that every single estimation method has a range
22 above the recommended range while less than half of his estimation methods
23 have any results below his lower bound.¹¹

24 Lastly, I note that neither Ms. Perry nor Dr. Stults undertake a cost of equity
25 study, but merely comment on the ROE that DTE Electric should be allowed.

⁸ Villadsen Direct, Figure 9 p. 34 versus Villadsen Direct Testimony in U-21297, Figure 10 p. 39.

⁹ Exhibit A-39, DD12. The Public Service New Mexico rate case was appealed to the NM Supreme Court on March 14, 2024, and the case has, to the best of my knowledge, yet to be resolved.

¹⁰ See Exhibit A-39, DD6 for details.

¹¹ Walters Testimony, Figure CCW-5, p. 58.

Without a contemporaneous study of the cost of equity, they offer no evidence to support a specific ROE or direction of change for the ROE.

Q12. How would you describe MPSC Staff's and Intervenors' recommended ROEs?

A12. The recommended ROEs are at or lower than DTE Electric's currently allowed ROE of 9.90 percent and lower than the ROE most recently allowed in Michigan¹² despite indications that the cost of equity has increased. Of note, the Commission has in the past acknowledged the importance of monitoring "a variety of market factors in future applications, including market reactions to recent events and measures of volatility and uncertainty, as well as measures of investor confidence, and the utility's risk profile."¹³ Therefore, the fact that interest rates are higher, while betas and growth rates are comparable to those in DTE Electric's most recent case needs to be acknowledged through an increase in the allowed ROE.

In the case of Mr. Coppola, placing $\frac{1}{2}$ weight on the DCF results and only $\frac{1}{4}$ on each of the CAPM and risk premium results downward biases the ROE results. Specifically, if Mr. Coppola were to take a simple average of the results from his three models, the average ROE would increase to 10.08 percent (after his 0.05 percent rounding) for an increase of more than 20 basis points.¹⁴

Mr. Walters resorts to "historic" betas using data back to 2014¹⁵ to obtain his lower than merited CAPM as the historic betas downward bias his CAPM by about 30 basis points. For the DCF model, I consider Mr. Walters' sustainable growth model flawed and therefore it should be ignored. Leaving out the sustainable DCF model, the average of Mr. Walters' DCF estimates increases

¹² Most recently the Commission approved an ROE of 9.90% in both Case Nos U-21389 and U-21297.

¹³ Michigan Public Service Commission, Order in U-20561, p. 177.

¹⁴ Comparing the peer group simple average of 9.98% = (9.26%+10.57%+10.10%)/3 to the weighted average of 9.80% calculated by Mr. Coppola in Exhibit AG-27.

¹⁵ Walters Testimony, page 46.

by 20 basis points.¹⁶ For the risk premium models, I am concerned that Mr. Ufolla's risk premium model, which relies on Treasury bond yields as described on pages 19-20 of his testimony, is biased due to the inclusion of periods of very high bond yields or large spreads between utility bond yields and Treasury bond yields. As the result is unusually low and outside the range found by other witnesses, I ignored this result in the modified row for Mr. Ufolla's risk premium in Table 2 above.

Lastly, I consider Mr. Bandyk's reliance on only a multi-stage DCF model¹⁷ insufficient during the energy transition and his use of unconventional sources for his market risk premium in the CAPM downward biases his CAPM substantially.

Dr. Stults' ROE related testimony focuses on (i) no credit rating agency has reacted negatively¹⁸, (ii) DTE Electric's authorized ROE should be reduced, and (iii) DTE Electric has requested a higher ROE than awarded in recent years. However, Dr. Stults does not perform any analysis of the current cost of equity such as DTE Electric is and therefore has no basis for suggesting a lower ROE.¹⁹ As noted above, indications are that the cost of equity has increased as noted in my direct testimony p. 14. Further, she fails to acknowledge that credit rating agencies are concerned about creditworthiness and not the return to shareholders. As such, she is focused on one of the Supreme Court's requirement; namely that (i) the return should be adequate, under efficient and economical management for the utility to maintain and supports its credit ...", but ignores the two other tenants of *Hope* and *Bluefield*. These additional requirements are that (ii) the return should be commensurate with the returns on investments in other enterprises having corresponding risk and (iii) the return

¹⁶ Calculated as (Average of DCF models w/o Sustainable GR) – Average of all 3 DCF Models; see Exhibit A-39, Schedule DD3 for details.

¹⁷ Bandyk Testimony, page 19-20

¹⁸ Stults Testimony, p 11

¹⁹ Stults Testimony, p. 13.

1 should be reasonably sufficient to assure confidence in the financial soundness
2 of the utility.²⁰

3 Ms. Perry focuses on recently allowed ROEs in Michigan and nationwide to
4 suggest that the ROE requested by the Company is too high,²¹ but fails to
5 acknowledge that DTE Electric's requested equity percentage is lower than that
6 allowed to the average electric utility and that the cost of equity is forward-
7 looking.

8 Lastly, another factor driving the difference between my estimate of DTE
9 Electric's ROE and Staff and the Intervenor's estimates is that they (with the
10 exception of Mr. Bandyk) ignore the effects of financial risk on the cost of
11 equity. This is contrary to not only finance theory and practice, but also to
12 regulatory precedent. Indeed, Mr. Walters provides a work paper he
13 downloaded from S&P Global that includes levered and unlevered betas for his
14 proxy group.²² Clearly, S&P Global and Mr. Walters are aware that financial
15 leverage adjustments for the cost of equity are well accepted by the market and
16 for the regulated utility industry.

17 While I cover the relationship between the equity percentage and the cost of
18 equity in Section II.C, I note that standard Masters of Business Administration
19 (MBA) textbooks such as Berk & DeMarzo (2013), Brealey, Myers & Allen
20 (2011), Ross, Westerfield & Jaffe (2014)²³ as well as commercial providers of
21 cost of capital estimates (e.g., Duff & Phelps)²⁴ and regulatory commissions²⁵

²⁰ See, for example, Villadsen Direct, pp. 9-10.

²¹ Perry Testimony, p. 9.

²² Walters Exhibit CCW Confidential WP 22, tab "Instructions.

²³ See, for example, Berk & DeMarzo 2013, p. 489. Similar comments appear in Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2014, *Principles of Corporate Finance*, 11th edition, McGraw-Hill Irwin (Brealey, Myers & Allen 2014), p. 433 and Ross, S., Westerfield, R., Jaffe, J. (2014), *Corporate Finance*, pp.492-95.

²⁴ See, for example, Duff & Phelps, "2017 Valuation Handbook – U.S. Guide to Cost of Capital," p. 1-15.

²⁵ See, for example, Federal Communications Commission, "Report and Order, Order and Order on Reconsideration, and Further Notice of Proposed Rulemaking," FCC 16-33, issued March 30, 2016,

1 have recognized that the financial risk of a company increases with its
2 proportion of debt that is used to finance its operations (i.e., its leverage). For
3 example, the Florida Public Service Commission has relied on a formula
4 approach to the allowed ROE for water utilities that explicitly recognized that
5 a lower equity percentage merits a higher ROE.²⁶ I discuss the issue of financial
6 leverage in the Section II.D below.

7 **Q13. Do you have any preliminary comments on Staff's or Intervenor's**
8 **criticisms of your recommended ROE?**

9 A13. First, for the CAPM / ECAPM I did not rely on the After-Tax, Weighted-
10 Average Cost of Capital ("ATWACC") approach²⁷ and as the risk premium
11 relies on data from a sample with an average of a little over 50 percent equity,
12 the results are directly comparable. Second, I continue to find that it is necessary
13 to consider capital structure when determining the cost of equity²⁸ and therefore
14 discuss my reasons below in Section II.D. Third, it is absolutely necessary to
15 use current estimates of the systematic risk, as I do as well as do Mr. Ufolla,
16 Mr. Coppola, and Mr. Bandyk. The critique of that as well as the use of
17 estimates that are up to 10 years old should simply be ignored.²⁹ Lastly, the
18 critique of my ECAPM is misplaced, but because it has little to no effect on the
19 estimated ROE, I have relegated any discussion to an appendix.³⁰

pp 3189-3190 and p. 3210. The Federal Energy Regulatory Board in Cost of New Entry studies for electric (Docket ER14-2940-000, November 28, 2014, ¶81), the Surface Transportation Board (Docket No. EP 558 (Sub-No 18) as well as foreign regulators such as the British Columbia Utilities Commission ("Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23," issued September 5, 2023). In addition, the California Public Utilities Commission relied on Hamada unlevered / relevered data in D.12-12-034.

²⁶ Florida Public Service Commission, "Order No. PSC-2017-0361-FOF-WS," p. 126 lists the equity percentage as 49.27.

²⁷ Villadsen Direct, Figure 10, p. 35.

²⁸ Bandyk Testimony, p. 18 acknowledges that it is necessary to reflect capital structure in the determination of the relevant cost of equity.

²⁹ Walters Testimony, pp. 57 and 45.

³⁰ I note that the Ufolla Testimony, p. 17 makes a similar observation.

II.B. Response to Relied Upon Models and Inputs

Q14. Do you have any comments on Staff’s and Intervenor’s selection of comparable companies?

A14. Yes. Mr. Walters uses the same electric utility companies as I except ALLETE, which I also would exclude today due to its recently announced plan to be acquired by Canada Pension Plan Investment Board and Global Infrastructure Partners.³¹ Mr. Bandyk similarly relies on the same companies as do I but excludes Alliant – I found no explanation for this exclusion in the Bandyk Testimony.³² Like Mr. Ufolla, Mr. Coppola, and Mr. Walters, I find Alliant to be an appropriate comparator. Mr. Ufolla relies on 18 electric utilities including 13 of the electric utilities I use plus an additional five companies (Avangrid, Consolidated Edison, Dominion, Eversource, PPL Corporation),³³ while Mr. Coppola relies on 10 electric utilities of which eight overlap with my sample,³⁴ while he also adds Consolidated Edison and PNM Resources. First, I think it is preferable to have more peer utility companies in the comparable group than do Mr. Ufolla and Mr. Coppola given the availability of such companies. Second, I am concerned that Mr. Ufolla’s and Mr. Coppola’s samples include distribution only companies.³⁵ Additionally, I am puzzled that Mr. Coppola includes Avangrid and PNM Resources, which only recently abandoned their merger agreement.³⁶ Third, Mr. Coppola’s sample has an

³¹ ALLETE Press Release, “ALLETE Enters Agreement to be Acquired by a Partnership Led by Canada Pension Plan Investment Board and Global Infrastructure Partners to Advance ‘Sustainability-in-Action’ Strategy,” May 6, 2024. [ALLETE Enters Agreement to be Acquired by a Partnership Led by Canada Pension Plan Investment Board and Global Infrastructure Partners to Advance ‘Sustainability-in-Action’ Strategy | ALLETE, Inc.](#)

³² See also Bandyk Workpapers, tab “Hamada Beta.”

³³ See Exhibit A-39, Schedule DD1 for a comparison of the samples the witnesses relied upon.

³⁴ *Ibid.*

³⁵ Both include Consolidated Edison and Mr. Ufolla also includes Eversource.

³⁶ PNM Resources, “PNM Resources Announces Avangrid Termination of Merger Agreement, Schedules Financial Update,” Press Release, January 2, 2024; [PNM Resources Announces Avangrid Termination of Merger Agreement, Schedules Financial Update \(prnewswire.com\)](#)

1 average growth rate that is below that of other witnesses, which plausibly is
2 the cause for his lower DCF results³⁷.

3 **Q15. Do you have a response to the critique of your sample selection?**

4 A15. Yes. Mr. Coppola critiques my proxy group for not meeting my own selection
5 criteria. I respectfully disagree. At the time of the selection, ALLETE had yet
6 to announce its sale and other companies' transactions³⁸ did not constitute 25
7 percent or more of the market value. Moreover, as I do not adjust for
8 differences in size and the literature on the impact on cost of equity from size
9 is disputed in the academic literature,³⁹ I disagree with eliminating entities that
10 are larger or smaller than DTE Electric as long as the entities have sufficient
11 trading volume to, in a statistical sense, reliably estimate the cost of equity.
12 Additionally, if Mr. Coppola believes the CAPM underestimates the cost of
13 equity for small companies and over estimates it for large companies,⁴⁰ this
14 effect can be eliminated by adding/subtracting the empirical premium.⁴¹ Lastly,
15 through the elimination of companies, Mr. Coppola ends up with a sample
16 whose average growth rate is lower than those of other witnesses – specifically
17 the elimination of larger companies such as Duke, Exelon, Nextera and
18 Southern Company eliminates entities, which are poised for growth through
19 investments and (by that measure) are comparable to DTE Electric.⁴²
20 As I do not believe the sample differences are the key drivers of the difference
21 in results, I shall not address the samples selected by the witnesses further.

³⁷ Mr. Ufolla's average sample beta is 0.94, Mr. Coppola's average sample beta is 0.91 and the Villadsen Direct found an average sample beta of 0.93. The samples' average growth rate before any eliminations or adjustments was 5.7% for Mr. Ufolla, 5.215% for Mr. Coppola (taking into account only those companies for which Mr. Coppola reports a growth rate in AG-28, p. 1), 6.29% for Mr. Walters and 5.3% in the Villadsen Direct.

³⁸ Coppola Testimony p. 79 mentions American Electric Power ("AEP") and CenterPoint Energy.

³⁹ For example, Kroll's Cost of Capital Navigator continues to report size premia, while, for example, Ron Alquist, Ronen Israel & Tobias Moskowitz, "Fact, Fiction, and the Size Effect," *The Journal of Portfolio Management*, vol 45, 2018, concludes there is no size effect.

⁴⁰ Coppola Testimony, p. 77 states that he removes companies "due to size considerations."

⁴¹ Using the size premium that is reported by, for example, Kroll Cost of Capital Navigator.

⁴² Coppola Testimony, p. 77. Villadsen Direct, p. 44 found DTE Electric to have higher capital expenditures than the sample.

1 **Q16. What is your view on the models and inputs relied upon by Staff and**
2 **Intervenors?**

3 A16. All witnesses (including myself) that provide an explicit recommendation use
4 versions of the CAPM and DCF model. Mr. Ufolla, Mr. Coppola, Mr. Walters,
5 and I also estimate one or more versions of a risk premium model.

6 A key concern with Mr. Coppola's use of the models when recommending a
7 return on equity is that he over-emphasized the DCF model's results, which he
8 weighs by $\frac{1}{2}$ while the CAPM and Risk Premium is weighted by only $\frac{1}{4}$ each.
9 The modified results in Table 2 above therefore use a more common approach
10 and weigh the results equally ($\frac{1}{3}$ each).⁴³

11 I summarized the results reported by the witnesses and those obtained from key
12 modifications in Table 2 above. Of note, Table 2 above does not consider
13 financial leverage unless the witness incorporates such leverage. I consider the
14 impact of financial leverage in Section II.C below.

15 I next address my concerns with the model implementations in turn.

16 **II.B.1. DCF Models**

17 **Q17. How did MPSC Staff and Intervenors implement their DCF models?**

18 A17. Mr. Ufolla implements a single-stage DCF using the average of the company-
19 specific growth rates from Yahoo, Value Line, and Zacks. He obtains his
20 dividend yield from Value Line.⁴⁴ Mr. Coppola implements a single-stage DCF
21 model using company specific growth rates from Value Line and Yahoo, which
22 he averages. He relies on a 30-day average stock price ending June 12, 2024
23 and a forecasted dividend from Value Line.⁴⁵ Mr. Walters implements a

⁴³ For example, the Federal Energy Regulatory Commission (Order 569-A) and the Surface Transportation Board (STB Ex parte No. 664 (Sub-No. 1)) assign equal weight to the methods they rely on.

⁴⁴ Ufolla Testimony, p. 12.

⁴⁵ Coppola Testimony, Exhibit AG-28.

1 constant-growth model, a sustainable growth model, and a multi-stage growth
2 model. In his constant-growth DCF model, Mr. Walters relies on the average
3 of three professional security analysts' company-specific growth rate forecasts
4 in his constant growth DCF model, using 13-week average stock prices ending
5 June 24. His sustainable growth DCF model relies solely on Value Line
6 forecasts, while his multi-stage DCF uses analysts forecasts and Gross
7 Domestic Product ("GDP") growth.⁴⁶ Finally, Mr. Bandyk simply adopts the
8 Villadsen Direct's multi-stage After-Tax Weighted Average Cost of Capital,
9 which he then adjusts to 58 percent equity (Villadsen Direct's average market
10 value equity percentage for the sample).⁴⁷

11 **Q18. What comments do you have on these models and implementations?**

12 A18. Mr. Ufolla uses the average of the growth rates from Yahoo, Value Line and
13 Zacks as his company-specific growth rate. However, the Yahoo growth rate
14 for OGE Energy Corp is negative 12.34 percent, which is not a reliable going
15 forward estimate as it would cause the company to fail. Therefore, it would be
16 more appropriate to rely solely on the growth rates from Value Line and Zacks
17 (the average of which is 5.75 percent and in line with the sample average).⁴⁸
18 Using that growth rate for OGE results in its DCF-based cost of equity being
19 10.49 percent and the sample average and median becomes 10.13 percent and
20 9.85 percent, respectively.⁴⁹ Second, Mr. Ufolla relies on a formula that
21 determines the year one dividend yield using $\frac{1}{2}$ of the company-specific growth
22 rate. It would be more appropriate to grow the dividend yield by the full growth
23 rate, which would increase the DCF estimate by a small amount.

24 Mr. Coppola relies on lower growth rates than Staff, Mr. Walters, and myself.
25 This appears to be caused by his elimination of large growth entities, as noted

⁴⁶ Walters Testimony, Exhibit AB-6 to AB-11.

⁴⁷ Bandyk Testimony, Exhibit CUB-9.

⁴⁸ Ufolla Testimony, Exhibit S-4, Schedule D-5.

⁴⁹ It could also be appropriate to eliminate Dominion, whose DCF cost of equity estimate is 16.32% and therefore more than 1.5 times the average (which is FERC's elimination criteria). In Table 2, I eliminated the negative growth rate for OGE and Dominion to be conservative.

1 above, which plausibly downward biases his results by 15 to 109 basis points.⁵⁰

2 As Mr. Coppola relies on a single-stage growth DCF model, a reduction in the
3 growth rate of 15 basis points results in a reduction in the estimated ROE of 15
4 basis points. My direct testimony found an average growth rate of 5.3 percent,
5 Mr. Ufolla found an average growth rate of 5.7 percent, and Mr. Walters
6 consensus growth rate is 6.29 percent, so Mr. Coppola is 0.15 percent, 0.55
7 percent and 1.14 percent lower. I find a reasonable measure of the downward
8 bias is 0.15 percent to 1.14 percent.

9 Mr. Walters' sustainable growth model suffers from at least two issues. One, it
10 necessarily relies on only one source for its growth rates – Value Line. Two,
11 an input to the model, the expected ROE as forecasted by Value Line averages
12 11.13 percent,⁵¹ but Mr. Walters calculates an average ROE of 9.10 percent
13 using his sustainable growth model.⁵² This is simply inconsistent, and Mr.
14 Walters sustainable growth model should be ignored. Looking solely to Mr.
15 Walters' Constant Growth Model (Analysts' Growth) and Multi-Stage DCF
16 Model, the average of his DCF results changes from 9.45 percent to 9.63
17 percent.

18 Mr. Bandyk relies on my multi-stage DCF, while Mr. Ufolla, Mr. Coppola, Mr.
19 Walters and I all include a single-stage model. Thus, if Mr. Bandyk wants to
20 use my results and incorporate his adjustment, he ought to use an average of the
21 single-stage and multistage models. Doing so would increase his DCF-based
22 results from 8.66 percent to 9.61 percent with the single-stage DCF resulting in
23 a cost of equity of 10.43 percent.⁵³

⁵⁰ I compare the average growth rate from the Ufolla Testimony, the Walters Testimony, and the Villadsen Direct to the 5.15% average growth rate, I obtain, when I average the nine growth rates displayed in AG-28, column (h). It appears that the 4.63% reported as the average for the column assumes 10 companies in the average although there are only 9 as the row for Alliant Energy shown "N.M.".

⁵¹ CCW Public WP 8, Tab AB-9.

⁵² CWW Public WP 8, Tab AB-10.

⁵³ See Exhibit A-39, DD9 for details.

1 **Q19. How about Staff's and Intervenors' criticisms of your implementation of**
2 **the DCF model?**

3 A19. I address the critique of considering financial leverage in Section II.C below
4 and therefore respond only to other critiques here.

5 I disagree with Mr. Walters that I should have placed more weight on the multi-
6 stage DCF model.⁵⁴ As I explained in my direct testimony, p. 38, the multi-
7 stage DCF results are out-of-line with other estimates and the general GDP
8 growth that is used in the multi-stage model in later years may fail to capture
9 the transition towards a low-carbon economy, which may take longer than what
10 the growth rates in the multi-stage DCF model reflects.⁵⁵ Mr. Ufolla and Mr.
11 Coppola rely on a single-stage DCF model and thus reflect company-specific
12 growth in their models.

13 **II.B.2. CAPM-Based Models**

14 **Q20. How do Staff and Intervenors implement the CAPM?**

15 A20. Mr. Ufolla implements the CAPM using a forecasted risk-free rate of 3.85
16 percent, Value Line betas and a MRP, which reflects the historical difference
17 between the total return on the S&P 500 and the income returns on long-term
18 government bonds (6.80 percent).⁵⁶

19 Mr. Coppola implements his CAPM using a forecasted risk-free rate of 4.05
20 percent, Value Line betas and a MRP of 7.17 percent, which he obtains from
21 Ibbotson's data up to 2022.⁵⁷

22 Mr. Walters implements nine versions of the CAPM, where he varies the risk-
23 free rate, betas and the MRPs. Specifically, he relies on a forecasted risk-free

⁵⁴ Walters Testimony, p. 61.

⁵⁵ My multi-stage DCF reflects analysts' growth rates during the first five years, then linearly moves the growth rate towards the GDP growth rate and fully reflects the GDP growth after year 10.

⁵⁶ Ufolla Testimony, Exhibit S-4, D-5.

⁵⁷ Coppola Testimony, Exhibit AG-29.

rate of 4.30 percent and a current risk-free rate of 4.57 percent. Mr. Walters uses Value Line betas as do all other witnesses, current betas from S&P Global and then also uses so-called historical betas, which are calculated as an average from 2014 to today.⁵⁸ The MRP is (i) obtained from Duff & Phelps and matched with their recommended risk-free rate,⁵⁹ (ii) based on a risk-premium derived method and matched with a forecasted risk-free rate, or (iii) based on a DCF model of the S&P 500 and matched with a forecasted MRP.

Unlike the other witnesses, Mr. Bandyk accounts for differences in financial leverage by relying on the average Hamada adjusted beta from my sample.⁶⁰ Notably, Mr. Bandyk agrees “on the need to adjust beta to reflect that a higher level of debt within a company’s capital structure increases the risk of equity.”⁶¹ He then implements the CAPM using a risk-free rate of 4.0 percent, Value Line betas and a MRP of 4.87 percent, which is calculated as the average of the MRP reported by IESE, the Kroll recommended MRP, and one of Damodaran’s MRPs.⁶²

Q21. What comments do you have on Mr. Ufolla’s CAPM implementation?

A21. While Mr. Ufolla’s risk-free rate is lower than that of other witnesses and lower than the current yield, I agree with using a forecasted rate as well as with the use of Value Line betas and a historical arithmetic average. Hence, my only modification to his CAPM other than to take financial leverage into account is to calculate the CAPM-based cost of equity using the lowest risk-free rate other than Mr. Ufolla’s; namely the 4 percent suggested by Mr. Bandyk. This results in an increase in the CAPM-based ROE of 15 basis points.

⁵⁸ Walters Testimony, pp. 45-46.

⁵⁹ Duff & Phelps recommend using their MRP with the higher of the normalized risk-free rate and the current risk-free rate. Mr. Walters implement the use of the current risk-free rate as the average over the most recent 13 weeks.

⁶⁰ Bandyk Testimony, Workpapers, tab “CAPM.”. Both Kroll and Damodaran report several versions of the MRP as explained below.

⁶¹ Bandyk Testimony, p. 17.

⁶² Bandyk Testimony, Workpapers, tab “CAPM.”

1 **Q22. Do you have any comments on Mr. Coppola's CAPM implementation?**

2 A22. I agree that Mr. Coppola's inputs to the CAPM are reasonable and suggest no
3 modifications other than to take financial leverage into account.

4 **Q23. What are your views on Mr. Walters' CAPM implementation?**

5 A23. First, it is imperative that betas reflect the best current estimate of the systematic
6 risk. Therefore the historic average of betas from 2014 to present are simply
7 not relevant. Of note, 2014 betas reflect market data for the period 2009-2014,
8 while the 2015 data reflect market data for the period 2010-2015, etc. Thus,
9 some years are over-represented, while current data are included only once.
10 The reliance on historic betas downward biases his CAPM results by 0.41
11 percent to 1.36 percent.⁶³ Consequently, rather than the average 10.39 percent
12 Mr. Walters finds, a more representative CAPM estimate using Mr. Walters'
13 data is 10.67 percent.⁶⁴ Second, regarding the S&P Global Intelligence betas,
14 the document relied upon⁶⁵ clearly shows that it is fundamental to unlever and
15 relever the betas to take into account DTE Electric's capital structure and that
16 the data relied upon to obtain the asset beta are market values. Thus, the
17 document looks to the same approach as I have. Mr. Walters fails to take that
18 into account when implementing his CAPM based on the S&P Global
19 Intelligence betas and therefore downward biases his CAPM results.

20 **Q24. What are your reactions to Mr. Bandyk's CAPM implementation?**

21 A24. I have two concerns with Mr. Bandyk's CAPM. First, he relies on an
22 exceptionally low MRP and second, there are some inconsistencies in the use
23 of his sources. For example, Mr. Bandyk uses the recommended MRP from

⁶³ Walters Testimony, WP-8, Tab AB-18 p. 1 with the 0.41 percent determined as the minimum difference between the Historical Beta and the Current S&P Global Market Intelligence Beta and the 1.36 percent determined as the maximum of the difference between the Current Beta and the Historical Beta.

⁶⁴ Determined as the average of the results using current VL betas and current MI betas from Table CCW-8, tab AB-18.

⁶⁵ Walters Exhibit CCW Confidential WP 22, tab "Instructions."

Kroll, but fails to acknowledge that Kroll states that this MRP should be used with the higher of the current risk-free rate and that recommended by Kroll.⁶⁶ Thus, if Mr. Bandyk wants to use the Kroll MRP, he needs to combine that with the current risk-free rate; e.g., 4.57 percent as calculated by Mr. Walters or the end-of-July reported market yield on U.S. Treasury Securities at 20-Year maturity of 4.56 percent.⁶⁷

Mr. Bandyk takes issue with my historic MRP saying that historic estimates are flawed because they are “extremely sensitive to the historical time period selected” and are “subject to the problem of survivorship bias.”⁶⁸ Instead, he estimates his own MRP based on three sources. There are several issues with this approach. Most glaringly, Mr. Bandyk relies on *Kroll*’s normalized MRP of 5.0 percent, but he fails to mention that the normalized MRP is derived using *historic* data. This is completely contradictory to the arguments he levies against my historic MRP values. Even then, he fails to note that *Kroll* recommends using the MRP in combination with a normalized risk-free rate, which is the higher of 3.5 percent or the spot yield.⁶⁹ Using the spot-yield on the 20-year U.S. Treasury yield of 4.57 percent would increase Mr. Bandyk’s ROE estimates by close to 60 basis points.⁷⁰

Next, Mr. Bandyk also relies on Damodaran’s implied risk premium derived MRP. This MRP is about 90 bps below any other suggested MRP,⁷¹ but it relies on a very short period (12 months in the case of the model used by Mr. Bandyk)⁷² to assess the cash payout to shareholders and assumes this is

⁶⁶ Kroll, “Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024,” June 6, 2024, p. 5.

⁶⁷ Walters Testimony, p. 45. Federal Reserve, FRED; [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/series/STLSTREAS20)

⁶⁸ Bandyk Testimony, p. 15.

⁶⁹ See footnote 66.

⁷⁰ Federal Reserve, FRED; [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/series/STLSTREAS20)

⁷¹ Mr. Ufolla uses 6.80%, Mr. Coppola uses 7.17%, Mr. Walters uses 5.00%, 7.17% and 8.45% while Villadsen Direct Testimony presented a range of 6.37% to 7.17%.

⁷² The 4.11% cited by Mr. Bandyk is consistent with Professor Damodaran’s figures for the 12-month trailing ERP ; Damodaran Online, <https://pages.stern.nyu.edu/~adamodar/>.

representative for the going forward period. Of note, Professor Damodaran's July 2024 Smoothed ERP is 5.91 percent or 1.80 percent higher than the MRP Mr. Bandyk chooses from the Damodaran website.⁷³ Finally, he relies on an MRP estimate from the 2023 IESE Business School survey. Survey data can be problematic and should not be considered. A study by Professor Ibbotson noted:

When using this [survey] method, one attempts to obtain the estimates from the market participants themselves. But there are a number of problems with this approach. Most of these investors have no clear opinion about the long-run outlook. Many of them have only very short-term horizons. Individual investors often exhibit extreme optimism or pessimism and make pro-cyclical forecasts... (notes omitted)⁷⁴

Professor Ibbotson goes on to note the problems with replicability, the determination of the horizon over which the forecast is made, and the very large variation in forecasts among participants. I concur and find for these reasons that surveys lack reliability. Taken together, Mr. Bandyk's MRP estimate has numerous problems that downwardly bias his ROE estimates to below almost every CAPM estimate put forth by any witness in this proceeding. Simply put, Mr. Bandyk's CAPM estimates should not be given any weight by the Commission.

To account for the downward bias in Mr. Bandyk's CAPM, I implemented it using Staff's MRP of 6.80 percent for a modified CAPM of 10.33 percent⁷⁵ and very much in line with the results obtained by other witnesses.

⁷³ Comparing the Damodaran MRP cited in Bandyk Workpapers U-21534 to that on the Damodaran website (see footnote 72).

⁷⁴ Roger G. Ibbotson, "The Equity Risk Premium," *Rethinking the Equity Risk Premium*, Research Foundation of CFA Institute, December 2011, p. 20

⁷⁵ From Bandyk workpaper. Calculated as $4\% + 0.93 * 6.8\% = 10.33\%$.

II.B.2.a. Staff and Intervenors' Critiques of Villadsen CAPM⁷⁶

Q25. Mr. Walters states that you fail to consider a more normalized estimate of beta.⁷⁷ How do you respond?

A25. Like Mr. Ufolla, Mr. Coppola, and Mr. Bandyk, I rely on Value Line betas (as is common in state and federal proceedings; including in Michigan). While I agree that the COVID-19 pandemic resulted in substantial volatility in financial markets during the early part of the pandemic,⁷⁸ it does not excuse the reliance on outdated betas from 2014 to today as Mr. Walters does. First, the pandemic has a profound impact on financial markets, so it is not evident that data from prior to the pandemic reflects current conditions. Second, the electric utility industry is in transition, so the systematic risk of electric utilities (as measured by beta) may have changed. In short, it is the current systematic risk that needs to be reflected and not an outdated measure.

Q26. Mr. Bandyk critiques your reliance on the historical arithmetic MRP.⁷⁹ How do you respond?

A26. First, all parties except Mr. Bandyk relied on a historic arithmetic average MRP. Mr Ufolla found that to be 6.80 percent, while Mr. Coppola, Mr. Walters and I used 7.17 percent. Mr. Walters also used 5.0 percent and a forecast of 8.45 percent,⁸⁰ while my Bloomberg forecast was 6.37 percent. Thus, Mr. Bandyk's MRP is simply an outlier at 4.87 percent and I disagree with his statement that there are "methodological problems that come with extrapolating a forward ERP from historic data."⁸¹ For example, the widely used MBA text of Brealey,

⁷⁶ I have relegated a discussion of the critique of the ECAPM to an appendix as Figure 11 in the Villadsen Direct, p. 39 shows that the difference between the CAPM and ECAPM estimates range from 0 to 0.1 percent.

⁷⁷ Walters Testimony, p. 57.

⁷⁸ Walters Testimony, p. 55.

⁷⁹ Bandyk Testimony, p. 17.

⁸⁰ See Villadsen Direct, Exhibit A-14, Schedule D5.17. I also calculated the MRP using FERC's methodology for MRPs of 7.87% and 7.90%. I did not implement a CAPM using these MRP results.

⁸¹ Bandyk Testimony, p. 17.

Myers and Allen (2017) uses the historical average market risk premium in their examples,⁸² the text of Ross, Westerfield and Jaffe (2012) notes that “We [the authors] are comfortable with an estimate based on the historical U.S. equity risk premium of about 7 percent...”⁸³ Among regulators the historical average MRP is also common as seen here where Staff, the AG and ABATE included this measure. Similarly, the Surface Transportation Board has specified the use of the historical average MRP in the manner Staff, the AG and ABATE do here.⁸⁴

II.B.3. Risk Premium Analyses

Q27. Do Staff or Intervenor witnesses consider the risk premium analysis?

A27. Yes. Mr. Ufolla, Mr. Coppola and Mr. Walters all implement one or more versions of the risk premium models. Mr. Bandyk does not use a risk premium model. However, Messrs. Ufolla, Coppola and Walters use slightly different versions of the model. Mr. Ufolla calculates the historical spread between the total return on utilities and the utility bond yield, then add this spread to the long-term utility bond return. He also implements a version that relies on Treasury bond yields instead of utility bond yields. Mr. Coppola similarly calculates the historical spread between the return on utilities and the expected A-rated utility bonds. He then adds the forecasted bond yield to the historical spread. Mr. Walters implements the risk premium using the allowed ROE and calculates the historical spread to both A-rated utility bonds and Treasury yields. He then adds this spread to the A-rated utility bond yield / the Treasury bond yield. These approaches all rely on the historical difference between the realized ROE (Mr. Ufolla, Mr. Coppola) or allowed ROEs (Mr. Walters) and a debt cost (Treasury bond yields or utility bond yields). These approaches fail

⁸² Brealey, Myers and Allen, *Principles of Corporate Finance*, 12th edition, 2017, pp. 164-166 and 199.

⁸³ Ross, Westerfield and Jaffe, *Corporate Finance*, 10^{ed}, 2012, p. 326.

⁸⁴ Surface Transportation Board, Decision in Docket No. EP 558 (Sub-No. 22), Aug. 5, 2019, p. 7.

to take into account the inverse relationship between the utilities' equity risk premium and the level of interest rates.⁸⁵ Simply put, as interest rates increase (decrease), the equity risk premium decreases (increases), so the risk premium is not constant over time. To more accurately estimate the premium, it is important to use a statistical relationship that takes the interaction of interest rates and earned or authorized returns into account. Taking the arithmetic average may underestimate (or overestimate) the premium and not fully reflect the interaction between bond yields and earned or allowed ROEs. This is particularly true if a Treasury bond yield is used during a period of substantial changes in the spread between utility bonds and Treasury bond yields. At the moment these considerations only seem to be a concern for Mr. Ufolla's risk premium model that relies on the Treasury bond yield (and which uses a very low forecasted 20-year yield). This explains the very low number Mr. Ufolla finds using the Treasury bond yield.⁸⁶ Because the equity market and the Treasury bond yields have moved in very different directions during part of the period considered by Mr. Ufolla (1931-2023), the impact of not taking the inverse relationship between interest rates and the risk premium into account is magnified. The results from this model are very different from the result he obtains from his risk premium model based on A-rated utility bond yields as well as from that obtained by other witnesses. It is also 115 basis points below Mr. Ufolla's other results (from the DCF, CAPM and A-rated utility bond risk premium analysis). I therefore consider that only the results from the A utility bond yields reflects the current cost of equity.

Q28. Do you have any other comments on the risk premium model?

A28. Yes, Mr. Bandyk refers to FERC Order 569 from 2019 as having rejected the risk premium model.⁸⁷ However, this is only a partial discussion of FERC's

⁸⁵ See, for example, Roger A. Morin, *Modern Regulatory Finance*, 2021 pp. 138-139 for an analysis of this relationship between allowed ROEs and bond yields.

⁸⁶ Staff Exhibit S-4, Schedule D-5, Tab "Risk Premium" And Historical Returns - Elec

⁸⁷ Bandyk Testimony, p. 23.

1 decision-making regarding the risk premium model. Specifically, in FERC
2 Opinion No. 569-A, the FERC concluded that “the Risk Premium model, with
3 adjustments, is sound.”⁸⁸ However, the DC. Circuit Court in 2022 remanded the
4 decision back to FERC as Opinion 569-A failed to explain and address prior
5 concerns.⁸⁹ Thus, the treatment of the Risk Premium model at FERC is
6 currently undecided.

7 Second, I note that except for Mr. Ufolla’s risk premium over the Treasury bond
8 yield from 1931 to 2023, the risk premium results the witnesses obtain are very
9 similar, so I shall not address the issue further.

10 II.C. Financial Leverage Adjustments

11 II.C.1. Preliminaries

12 **Q29. What do you cover in this section of your rebuttal testimony?**

13 A29. I respond to the critiques and misunderstandings of my Direct Testimony
14 regarding financial leverage. Specifically, I address the concerns of Mr. Ufolla,
15 Mr. Walters, and Mr. Coppola regarding the use of various methods to account
16 for financial leverage. I also address Mr. Bandyk’s use of the average capital
17 structure for the sample companies as a benchmark for DTE Electric. In doing
18 so, I discuss the financial economics underlying the approach and the regulatory
19 precedent for taking financial leverage into account. Finally, I assess the impact
20 on the Intervenor’s failure to consider the impact of their capital structure
21 recommendations on the ROE investors require.

⁸⁸ FERC Order 569-A issued May 21, 2020, ¶46.

⁸⁹ See, for example, VanNess Feldman, “DC Circuit Court of Appeals Puts FERC’s Revised Method for ROE Determination in Question,” August 10, 2022.

Q30. Please summarize Staff's and Intervenor's testimonies regarding financial risk.

A30. Collectively, Staff and Intervenor take issue with my use of an "ATWACC adjustment"⁹⁰ and my reliance on the textbook Hamada method,⁹¹ although Mr. Walters is confused as to the methods and results. For example, it appears that Mr. Walters incorrectly believes that I use the ATWACC method to derive my CAPM / ECAPM based recommendation.⁹² This led Mr. Walters to erroneously claim that the financial leverage caused me to recommend a ROE up to 11.90 percent.⁹³ As clearly stated in Villadsen Direct, I did not rely on the after-tax weighed average cost of capital method for my CAPM.⁹⁴ Specific critiques of the financial risk adjustment fall into the following categories:

1. *Market vs. book value of capital structures*: Mr. Ufolla is concerned about using market values in the overall cost of capital⁹⁵ and Mr. Walters states that book value capital structure of DTE Electric relative to the sample is the relevant comparison because DTE Electric's stock is not publicly traded.⁹⁶
2. *Adjusting for leverage*: Staff does not believe the Hamada method is applicable in a ratemaking environment.⁹⁷ Similarly, Mr. Coppola finds the method unsuitable in a regulatory environment and also finds the method leads to faulty and inflated results.⁹⁸

⁹⁰ Ufolla Testimony, p. 13; Walters Testimony, p. 61; Coppola Testimony, p. 83-85.

⁹¹ Ufolla Testimony, p. 17; Walters Testimony, pp. 61; Coppola Testimony, p. 88.

⁹² Mr. Walters' Table CCW-14 report an ECAPM (1.5%) Recommended ROE of 11.0% - 11.9%. These numbers do not appear in my direct testimony, which lists the ECAPM results as 10.8% - 11.7%. See Figure 10, p. 35 of Villadsen Direct. This also means that Mr. Walters' estimate of the financial leverage accounting for up to 90 basis points is wrong and based on data that is not relied upon in my testimony.

⁹³ Walters Testimony, Table CCW-14, p. 61. Clearly, there are no number in Villadsen Direct, Figure 10, p. 35 above 11.7%.

⁹⁴ Villadsen Direct, p. 31, footnote 65.

⁹⁵ Ufolla Testimony, p. 18.

⁹⁶ Walters Testimony, p. 63.

⁹⁷ Ufolla Testimony, p. 17.

⁹⁸ Coppola Testimony, p. 88.

- 1 3. *Regulatory Precedent*: Intervenor argue that the financial risk
- 2 adjustments lack regulatory precedent in the U.S.⁹⁹
- 3 4. *Sample Capital Structure*: Mr. Bandyk argues that the relevant capital
- 4 structure to adjust towards is the average market value capital structure
- 5 of the sample.¹⁰⁰

6 **Q31. How do you respond to Staff’s and Intervenor’s assertion that leverage**
 7 **adjustments are inappropriate and investors should only be compensated**
 8 **for capital invested in plant and equipment?**

9 A31. First, the leverage adjustment does not compensate for anything other than
 10 capital invested in plant and equipment. There is no change to the amount of
 11 capital earning a return – it is simply the equity portion of the rate base. Second,
 12 all Intervenor use publicly traded utilities when performing their DCF analysis
 13 and to estimate the Market Risk Premium used in their CAPM analysis. These
 14 publicly traded companies vary in their capital structure – the amount of debt
 15 and equity the company holds. Therefore, Intervenor and I are all using market
 16 values in our analyses; the difference is how we use market values to adjust for
 17 financial leverage.

18 Both the CAPM and DCF models rely on market data to estimate the cost of
 19 equity for sample companies, so the results reflect the value of the capital that
 20 investors hold during the estimation period (market values). The allowed return
 21 on equity is applied to the rate base, which is determined using the historical
 22 cost and hence reflects the net book value of assets. Taking differences in
 23 financial leverage into consideration **does not** change the value of the rate base
 24 and consequently does not depart from original cost ratemaking principles.
 25 Adjustment for differences in leverage does consider the fact that the more debt
 26 a company has, the higher the financial risk associated with an equity
 27 investment in that company. Furthermore, the higher risk to investors will

⁹⁹ Ufolla Testimony, pp. 17-18; Walters Testimony, p. 64-65.

¹⁰⁰ Bandyk Testimony, Workpapers, tab “Hamada Beta.”

1 increase the cost of equity capital raised through primary investing to fund
2 investments in plant and equipment to serve ratepayers.

3 **Q32. How should capital structure be considered to ensure that the allowed**
4 **returns meet the fair return standard?**

5 A32. The proportion of debt in the capital structure—also known as financial
6 leverage—influences the risk borne by equity investors. For a given degree of
7 business risk, a higher proportion of debt financing increases the expected
8 variability of equity returns. Thus, to compare the fair returns of two otherwise
9 identical firms, on a risk adjusted basis, the capital structures must be taken into
10 account. For example, if more debt is used, the greater financial risk imposed
11 by the greater financial leverage must be compensated by a commensurately
12 higher expected return on equity. Otherwise, the more leveraged firm will not
13 receive a fair return and will be at a disadvantage in the competition to attract
14 capital in equity markets.

15 **Q33. How does leverage relate to the cost of equity?**

16 A33. Financial risk or capital structure is a large topic in financial economics. The
17 principle that financial leverage amplifies the variability of equity returns and
18 thereby increases the financial risk to equity investors is a firmly established
19 core principal of corporate finance. It is directly connected to the Modigliani
20 Miller proposition that, except as influenced by the tax-deductibility of debt and
21 the cost of financial distress, the value of a firm's assets is independent of its
22 choice of financing. This intuitive framework means that some measures of the
23 overall cost of capital for firms with comparable systematic business risk should
24 be the same regardless of capital structure,¹⁰¹ even if the cost of the equity
25 and/or debt components of financing vary in proportion to the degree of
26 financial leverage.

¹⁰¹ Except in cases of extremely high or low leverage, where the tax and financial distress effects may dominate.

It is commonly recognized in finance textbooks that financial leverage impacts the cost of equity for a company. A replication from a standard MBA textbook is provided below:¹⁰²

COMMON MISTAKE Is Debt Better Than Equity?

Because debt has a lower cost of capital than equity, a common mistake is to assume that a firm can reduce its overall WACC by increasing the amount of debt financing. If this strategy works, shouldn't a firm take on as much debt as possible, at least as long as the debt is not risky?

This argument ignores the fact that even if the debt is risk free and the firm will not default, adding leverage

increases the risk of the equity. Given the increase in risk, equity holders will demand a higher risk premium and, therefore, a higher expected return. The increase in the cost of equity exactly offsets the benefit of a greater reliance on the cheaper debt capital, so that the firm's overall cost of capital remains unchanged.

As Professors Berk and DeMarzo further note:

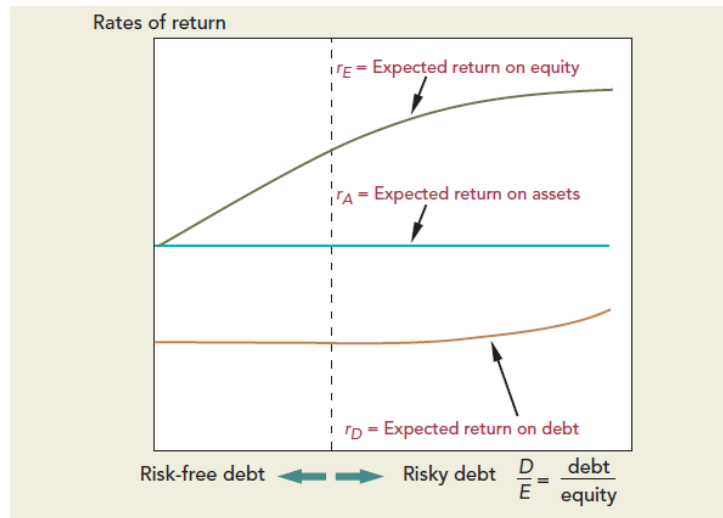
The levered equity return equals the unlevered return, plus an extra “kick” due to leverage...The amount of additional risk depends on the amount of leverage, **measured by the firm's market value debt-equity ratio, D/E...**¹⁰³ (emphasis added)

This relationship is further illustrated in Figure 1 reproduced from the seminal textbook *Principles of Corporate Finance* by Brealey, Myers, and Allen. It illustrates that as capital structure shifts to use a greater proportion of lower cost debt financing, the investor required return on equity (and debt, especially at higher leverage ratios) increases to compensate for the greater financial risk, such that the overall required return on assets remain unchanged.

¹⁰² Jonathan Berk and Peter DeMarzo, “Corporate Finance,” Third Edition, 2013 (Berk & DeMarzo 2013), p. 492.

¹⁰³ Berk & Peter DeMarzo 2013, p. 489. Similar comments appear in Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2014, *Principles of Corporate Finance*, 11th edition, McGraw-Hill Irwin (Brealey, Myers & Allen 2014), p. 433.

FIGURE 1: ILLUSTRATION OF THE MODIGLIANI MILLER PRINCIPLE¹⁰⁴



Financial economics textbooks leave no doubt that the cost of equity increases with financial leverage and that the relevant measure of financial leverage depends on market value. I—like other witnesses—estimate the cost of equity using market data in the CAPM and DCF-based models. Since the Risk Premium model is based on book values, the relevant leverage for this methodology is book value based.

Q34. Do you agree with Mr. Bandyk’s adjustment towards the average of the sample?¹⁰⁵

A34. No. I firmly disagree. The capital structure at which DTE Electric receives a rate of return is not the average of the sample, but the regulatory capital structure of 50 percent. Surprisingly, Mr. Bandyk did not even look towards the capital structure of DTE Electric’s parent company, DTE Energy, which has a lower market value equity percentage than the sample at about 56 percent.¹⁰⁶ The

¹⁰⁴ Brealey, Myers, and Allen, *Principles of Corporate Finance*, 10th Ed. (2011), p. 429, Figure 17.2.

¹⁰⁵ Bandyk Testimony, Workpapers, tab “Hamada Beta.”

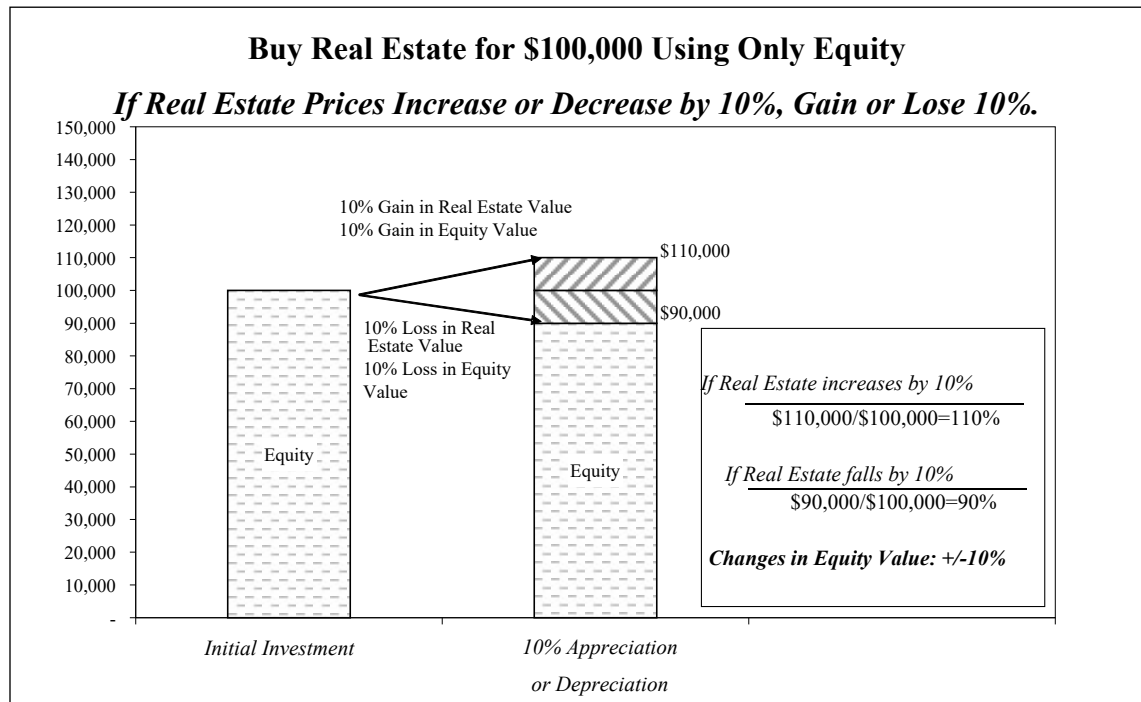
¹⁰⁶ Exhibit A-39, Schedule DD8.

impact hereof would be to increase the CAPM cost of equity estimated by Mr. Bandyk by 13 basis points.¹⁰⁷

Q35. Could you provide a numerical example to illustrate the impact of financial leverage on cost of equity?

A35. Yes. As a simple example, think of an investor who takes money out of her savings and invests \$100,000 in real estate. The future value of the real estate is uncertain. If the real estate market booms, she will realize a gain. However, if the real estate market declines, she will realize a loss. Figure 2 below provides an illustration of this:

FIGURE 2: RETURN ON AN ALL EQUITY INVESTMENT

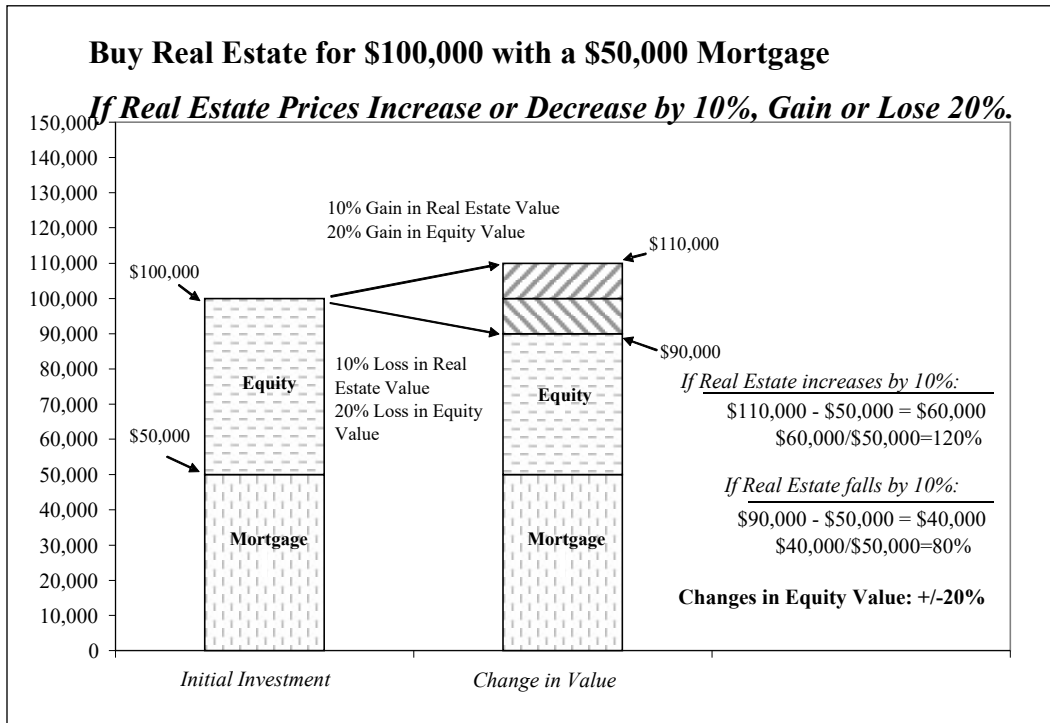


Compare this to the situation illustrated in Figure 3 below, where the investor finances the same real estate purchase using 50 percent cash from her savings (equity) and finances 50 percent using funds from a mortgage (debt). In this

¹⁰⁷ To see this, I simply compared the results in Bandyk Testimony, Workpapers tab "CAPM" with those obtained, when changing the equity percentage in tab "Hamada Beta" to 56%. See Exhibit A-39, DD9.

case, the variability in the investor's expected equity return is two-times greater than in Figure 2. The entire fluctuation of 10 percent from rising or falling real estate prices falls on the investor's equity investment, which is smaller (\$50,000) for the leveraged investment depicted in Figure 3 as compared to the all-equity \$100,000 investment shown in Figure 2. The equity return for the leveraged investment goes up or down by 20 percent in the leverage scenario even though the actual change in the value of the real estate (+/- 10 percent) is the same as depicted in Figure 2 for the all-equity investment. The lesson from this example is obvious: debt adds risk because, while there is more potential gain on the equity investment by using debt, there is a higher potential loss on that equity investment that goes with it. This concept is colloquially referred to as "high risk, high reward."

FIGURE 3: RETURN ON A LEVERAGED EQUITY INVESTMENT



1 **Q36. Do finance textbooks also address the question of how financial leverage**
2 **affects the cost of equity?**

3 A36. Yes. Standard textbooks on corporate finance provide examples, like the one I
4 presented above, to illustrate how the introduction of debt financing amplifies
5 the variability of equity returns and thus increasing the risk to equity holders
6 which causes them to demand higher expected returns. For example, Professors
7 Brealey, Myers, and Allen write:

8 Our example shows how borrowing creates financial leverage or
9 gearing. Financial leverage does not affect the risk or the expected
10 return on the firm's assets, but it does push up the risk of the
11 common stock. Shareholders demand a correspondingly higher
12 return because of this *financial risk*.¹⁰⁸

13 Similarly, Professors Berk and DeMarzo summarize the effect of leverage on
14 the cost of capital as follows:

15 [L]everage increases the risk of equity even when there is no risk
16 that the firm will default. Thus, while debt may be cheaper when
17 considered on its own, it raises the cost of capital for equity.
18 Considering both sources of capital together, the firm's average cost
19 of capital with leverage is ... the same as for the unlevered firm.¹⁰⁹

20 These statements by preeminent finance scholars in widely-used Corporate
21 Finance textbooks highlight two important points that can also be intuitively
22 observed based on the real estate investment example:

- 23 ► The variability of returns on the asset itself (*e.g.*, the piece of real estate) is
24 unchanged by the introduction of financial leverage, therefore “leverage

¹⁰⁸ Brealey, Myers and Allen (2017), *Principles of Corporate Finance*, 12th Edition, p. 446 (emphasis in original).

¹⁰⁹ Berk and DeMarzo (2014), *Corporate Finance*, 3rd Ed., p. 482 (emphasis in original).

1 does not affect the risk or the expected return on the firm's assets." Rather,
2 it is the risk and required returns of the equity and debt financing
3 instruments that are changed by the degree of financial leverage.

4 ► The mechanism by which leverage adds variability to returns is
5 independent of any effect of increased leverage on the risk that the firm
6 will be unable to fulfill its fixed financial obligations, and thus (as Berk
7 and DeMarzo put it) "leverage increases the risk of equity even when there
8 is no risk that the firm will default."

9 **Q37. Do financial economists recognize the calculation of after-tax weighted-**
10 **average cost of capital based on market values?**

11 A37. Yes. Looking to the most widely-used MBA textbook by Professor Brealey,
12 Myers, and Allen, they explain that:

13 The formula for the after-tax weighted average cost of capital is¹¹⁰:

$$14 \quad WACC = r_D(1 - TC) \left(\frac{D}{V} \right) + r_E \left(\frac{E}{V} \right)$$

15 where r_D and r_E are the expected rate of return demanded by investors in the
16 firm's debt and equity securities, D and E are the current market values of debt
17 and equity and V is the total market value of the firm ($V = D + E$).¹¹¹

18 Professors Brealey, Myers, and Allen then show that the after-tax weighted
19 average cost of capital is flat over a broad range of capital structures and
20 calculates the cost of equity using the same formula as I do.¹¹²

21 **Q38. Do financial economists recognize the Hamada technique?**

22 A38. Yes. The Technical Appendix (Appendix B) to my direct testimony provides a
23 detailed description of the standard textbook formulas used to implement the
24 Hamada technique for unlevering measured equity betas based on the proxy

¹¹⁰ This specification ignores preferred shares, but such financing could easily be added.

¹¹¹ Brealey, Myers and Allen (2014), p. 492.

¹¹² *Ibid.*

companies' capital structure to calculate "asset betas" that measure the proxy companies' business risk independent of the financial risk imposed by differing capital structures. I also note that standard MBA textbooks,¹¹³ practitioner texts,¹¹⁴ as well as the certified financial analyst (CFA) curriculum¹¹⁵ all describe the Hamada approach and use formulas like those relied upon in my direct testimony. Thus, the Hamada method is simply a well-established methodology taught in business schools as well as to CFA applicants.

Q39. What are the implications of these fundamental financial principles for the Intervenor's ROE results?

A39. Failing to recognize the impact of financial leverage on the cost of equity results in a downward bias in the cost of equity estimates. For example, the failure to recognize financial leverage downward biases the cost of equity by approximately 50-70 basis points.¹¹⁶

This approach is exactly as described in standard textbooks such as Brealey, Myers and Allen (2014), Berk and DeMarzo (2014), and Ross, Westerfield and Jaffe (2013) and the CFA curriculum,¹¹⁷ of which Mr. Walters is a charterholder.

¹¹³ Brealey, Myers and Allen (2014), pp. 492–493, Berk and DeMarzo (2014) pp. 415–417, Ross, Westerfield and Jaffe (2013), pp. 571–573.

¹¹⁴ Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, Inc., 2006, pp. 221–225; Leonardo R. Giacchino and Jonathan A. Lesser, "Principles of Utility Corporate Finance," Public Utilities Report, Inc., 2011, pp. 229–232.

¹¹⁵ See, for example, 2016 CFA Level I Volume 4: Corporate Finance and Portfolio Management, Chapter 4.

¹¹⁶ Comparing the Ufolla Testimony's CAPM without Hamada (p. 18) to my estimates results in a leverage impact of 0.64% to 0.72%, the Coppola Testimony p. 89 estimates the impact to be 70 basis points. This is consistent with my estimate of approximately 75 basis points (when taxes are considered in Exhibit A-39, Schedule DD11. The Walters Testimony p. 61 finds a leverage impact of 0.50% to 0.90% with the upper end of this improperly being based on data that did not impact my recommendation as explained above.

¹¹⁷ Brealey, Myers and Allen (2014), pp. 492–493, Berk and DeMarzo (2014) pp. 415–417, Ross, Westerfield and Jaffe (2013), pp. 571–573. 2016 CFA Level I Volume 4: Corporate Finance and Portfolio Management, Chapter 4. In all cases, they apply the Hamada method to the market value capital structure.

Q40. What do you conclude from the discussions above?

A40. I conclude that Staff's and Intervenor's ROE estimates are downwardly biased because they fail to account for the impact of financial leverage on the cost of equity, using standard financial techniques. Importantly, Mr. Coppola, Mr. Ufolla and Mr. Walters' results are in line with those I determined once financial leverage is taken into consideration. I also note that Mr. Bandyk, who does consider financial leverage important, obtains results in the range of 10.3 percent with an appropriate MRP. As noted above, I only consider the Hamada approach applied to the CAPM models of Staff and Intervenor's. Once appropriate modifications are made, as shown in Table 2 above, and the fact that DTE Electric has lower equity than what is represented in the proxy company data used to estimate the cost of equity is taken into account, both Staff's and Intervenor's modified results are consistent with a ROE of 10.50 percent.

II.C.2. Regulatory Decisions

Q41. Does adjusting for financial leverage have regulatory precedent?

A41. Yes. Multiple regulatory agencies in the U.S. and most outside of North America have adopted a similar approach. In the U.S., the Federal Communications Commission (FCC), the Surface Transportation Board (STB), and the FERC have accepted the use of weighted-average cost of capital methodologies to determine the cost of capital. Specifically, the FCC in a 2016 order acknowledged that it is reasonable (1) to use market values to estimate the capital structure and (2) derive an implied return on equity from the estimated weighted average cost of capital.¹¹⁸ Thus, the FCC acknowledged that market value capital structures are the relevant measure of leverage and impact the ROE using an approach similar to what I used. The FERC, in Cost

¹¹⁸ Federal Communications Commission, "Report and Order, Order and Order on Reconsideration, and Further Notice of Proposed Rulemaking," FCC 16-33, issued March 30, 2016, ¶270 and ¶322.

1 of New Entry (CONE) studies for the Pennsylvania, New Jersey and Maryland
2 (PJM),¹¹⁹ has used the weighted average cost of capital. The STB calculates the
3 weighted average cost of capital to assess the revenue adequacy for freight
4 railroads.¹²⁰ Considering next the Hamada approach, I note that the California
5 Public Utilities Commission in the past has relied on results from the method,¹²¹
6 the Oregon Public Service Commission staff commonly relies on a version of
7 the Hamada method to assess the impact of leverage on the cost of equity,¹²²
8 and the Florida Public Service Commission uses an equivalent methodology to
9 determine the ROE for small water utilities.¹²³

10 Looking outside the U.S., Mexico's *Comisión Reguladora de Energía*¹²⁴ relies
11 on the Hamada method, while regulators in the U.K., the Netherlands, Australia,
12 and New Zealand rely on a mixture of an after-tax weighted average cost of
13 capital and the Hamada method.¹²⁵ Of note, the British Columbia Utilities
14 Board in a recent decision acknowledged that

¹¹⁹ Federal Energy Regulatory Commission, "Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing," Docket ER14-2940-000, November 28, 2014, ¶59. See also, Federal Energy Regulatory Commission, "Order Accepting Proposed Tariff Revisions," Docket ER19-105-001, ER19-105-002, April 15, 2019, and ER-19-105-004, April 16, 2020.

¹²⁰ See, for example, Surface Transportation Board, "Docket No. EP 558 (Sub-No. 22), dated August 5, 2019, p. 15.

¹²¹ The California Public Utilities Commission ("CPUC") relied on Hamada unlevered / relevered data in D.12-12-034 at 38. Here the CPUC pointed to Southern California Edison's CAPM results and ROE range of 9.73 percent to 11.71 percent, which was derived using the Hamada method.

¹²² Opening Testimony of Matt Muldoon in Docket No. UE 319, Staff Exhibit 500, p. 15.

¹²³ Florida PUC for water and wastewater utilities (Order No. PSC-12-0339-PAA-WS); "Florida 2012 Order"), p. 4.

¹²⁴ CRE, "Directiva sobre la determinación de tarifas y el traslado de precios para las actividades reguladas en materia de gas natural DIR-GAS-001-2207."

¹²⁵ Villadsen, Bente, *et al*, "Risk and Return for Regulated Industries," Academic Press, 2017, Chapter 9 and references herein.

1 there is a need to account for leverage differences in the proxy group
2 of companies and acknowledges that the Hamada adjustment is an
3 appropriate approach to adjust...¹²⁶

4 **Q42. What do you conclude?**

5 A42. Several regulatory entities have found the methods used in financial economics
6 to consider leverage useful and all methods I use are well accepted, standardly
7 taught in corporate finance classes. A very recent acceptance was the British
8 Columbia Utilities Commission 2023 order that acknowledged the Hamada
9 approach. The methods are also standard curriculum in finance textbooks and
10 commonly used by practitioners who provide cost of capital measures.¹²⁷

11 II.D. Other Arguments Regarding the Level of the ROE

12 **Q43. Are there other topics you want to address regarding Intervenors' cost of**
13 **equity analysis?**

14 A43. Yes. I will address Mr. Bandyk's perception that

15 There is strong evidence from multiple observers and peer-reviewed
16 academic research that public regulatory commissions on average
17 have tended to set electric utility ROEs above what objective

¹²⁶ British Columbia Utilities Board, "Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23," issued September 5, 2023.

¹²⁷ For an example of a commercial data provider's application, see Duff & Phelps, "2018 Valuation Handbook—U.S. Guide to Cost of Capital," Chapter 1 pp. 1–21 For examples of tax authorities applications, see, for example, Utah Rule R884-24P-62 "Valuation of State Assessed Unitary Properties Pursuant to Utah Code Ann. Section 59-2-201," which states "The discount rate (k) shall be based upon a weighted average cost of capital (WACC) considering current market debt rates and equity yields." (<https://rules.utah.gov/publicat/code/r884/r884-24p.htm#T32>)

I understand it is common for taxes based on net present values to use a market value based after-tax weighted-average cost of capital as the discount rate.

1 observers in the financial community would arrive at using the
2 widely-accepted methods for estimating ROE.¹²⁸

3 I will also address the use of credit ratings, allowed and earned returns.

4 **Q44. What is your reaction to Mr. Bandyk's statement that regulatory utility**
5 **commissions set the allowed ROE above the cost of equity?**

6 A44. I disagree. Certainly, many commissions explicitly state that they set the
7 allowed ROE at the cost of equity. Thus, while there is some statistical
8 uncertainty surrounding the estimation of the cost of equity and some subjective
9 judgement by commissions, the statement would imply that Mr. Bandyk
10 believes the commissions consistently fail to set an appropriate ROE. To this
11 end, I note that there are voluminous records confirming that the regulatory
12 intent and policies are to set allowed ROE at the market cost of equity. The
13 legal standard for setting the ROE can be traced back to the Supreme Court's
14 1944 decision in *Hope*:

15 The rate-making process under the Act, i.e., the fixing of 'just and
16 reasonable' rates, involves a balancing of the investor and the
17 consumer interests...The return to the equity owner should be
18 commensurate with returns on investments in other enterprises
19 having corresponding risks. That return, moreover, should be
20 sufficient to assure confidence in the financial integrity of the
21 enterprise, so as to maintain its credit and to attract capital.¹²⁹

22 The broad language of the *Hope* decision allows a variety of specific
23 interpretations of the standard. However, since the 1970s it has become
24 customary to interpret the standard to be consistent with finance theory, which

¹²⁸ Bandyk Testimony, p. 6.

¹²⁹ Supreme Court Decision on *Hope*, 320 U.S. at 603.

1 defines the “commensurate return” as the rate of return investors expect
2 (**forward-looking**) when they buy stocks of comparable risk. This is a **market**
3 cost of equity that is closely related to the economic concept of **opportunity**
4 **cost**: a regulated utility must offer stock investors returns that are comparable
5 to that of other firms—regulated or not—that face similar financial risks.¹³⁰

6 Regulation is usually regarded as a substitute for competition. If the definition
7 of “fair return” is based on the theory of competitive markets, then regulation
8 should assure that the average expected rate of return on new utility investment
9 is equal to the utility’s cost of capital. That is the ultimate justification for
10 basing rate of return regulation on finance theory.¹³¹

11 **Q45. What is your view on using credit ratings and credit ratings reports to**
12 **determine the cost of equity?**

13 A45. Mr. Walters and Dr. Stults refer to credit ratings and the access to capital.¹³²
14 However, in doing so, they conflate the attraction of debt and equity capital –
15 credit ratings measure credit risk, while equity investors are considering the
16 return that is available on alternative investments of similar equity risk. The
17 fact that DTE Electric has maintained its credit rating and is able to attract debt
18 capital does not imply that the allowed ROE is commensurate with returns on
19 investments in other enterprises having corresponding risks. Because bond
20 holders absent default receive a fixed return on their investment, while equity
21 investors are exposed to variability in market returns, the risk to equity investors
22 is not only higher but different. Consequently, the statement by Fitch in 2023
23 that DTE Electric’s authorized ROE “compares favorably with industry
24 averages”¹³³ simply means that it was higher than the average and that Fitch did
25 not see an issue with DTE Electric’s creditworthiness. Similarly, Mr. Walters

¹³⁰ Professor Stewart C. Myers’s paper, “The Application of Finance Theory to Public Utility Rate Cases,” *Journal of Economics and Management Science* 3, 1972 pp. 58-97 (“Myers (1972)”), was seminal in bringing finance theory into public utility regulation.

¹³¹ Myers (1972), at p. 94.

¹³² Walters Testimony, pp. 18-19. Stults Testimony, pp. 9-13.

¹³³ Stults Testimony, p. 11.

cites to Moody's and Fitch regarding concerns related to consumer affordability and acknowledges that Moody's has changed its outlook for the industry from Positive to Negative, while Fitch sees the outlook as "deteriorating" for North American utilities.¹³⁴

I note that S&P defines credit ratings as "opinions about credit risk... the agency's opinion about the ability and willingness of an issuer... to meet its financial obligation in full and on time."¹³⁵ Further, S&P states: "Credit ratings ... are not indications of investment merit...the ratings are not buy, sell, or hold... or a measure of asset value... they speak to one aspect of an investment decision – credit quality..."¹³⁶ Therefore, Dr. Stults' and Mr. Walters' assertion that DTE Electric's credit rating has implications for the riskiness of its ROE is unfounded.

Q46. How about Dr. Stults' discussion that DTE Electric delivers "premium shareholder returns"?¹³⁷

A46. There are two problems with this statement. First, Dr. Stults is discussing DTE Energy and not DTE Electric, which violates the stand alone principle. Second, Dr. Stults is focused on historical events, whereas the cost of equity is a forward-looking concept. As stated by Professors Brealey, Myers and Allen in their widely used MBA text

the cost of equity (the **expected rate of return** demanded by investors in the firm's common stock).¹³⁸ [Emphasis added]

¹³⁴ Walters Testimony, pp. 18-19.

¹³⁵ S&P Global Ratings, "Guide to Credit Rating Essentials What are credit ratings and how do they work?" 2019, p. 4, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

¹³⁶ S&P Global Ratings, "Guide to Credit Rating Essentials What are credit ratings and how do they work?" 2019, p. 5, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

¹³⁷ Stults Testimony, p. 13.

¹³⁸ Brealey, Myers and Allen, Principles of Corporate Finance, 11'th Edition, 2014, p. 221.

Thus, Dr. Stults is not addressing the cost of equity in these statements.

Q47. What is your view on Ms. Perry’s reliance on recently allowed ROEs as indicators of the cost of equity for DTE Electric?

A47. Recently allowed ROEs are relevant for purposes of comparability and I use such data in my risk premium analysis. However, it is important, to consider the context in which such returns were allowed, as I do in my risk premium analysis. Ms. Perry focuses on recently allowed ROEs in Michigan and nationwide to suggest that the Company’s requested ROE “is excessive.”¹³⁹ For example, the average allowed return on equity for integrated electric utilities in 2024 for Q1 and Q2 is 9.75 percent and for 2023 the authorized ROE was 9.80. However, it is important to recognize that on average electric utilities have been awarded a higher equity percentage than what DTE Electric is requesting. For example, the average allowed equity percentage was 51.15 percent for 2023.¹⁴⁰ Thus, the 9.75 or 9.80 percent are downward biased in that the average utility has a higher equity percentage and hence weigh the equity more in the overall cost of capital that customers pay. Additionally, it is necessary to consider whether there are risk factors for DTE Electric that merit a higher or lower return on equity than those granted other integrated electric utilities. Of note, DTE Energy, the parent of DTE Electric, has approximately 45 percent coal generation - - indicating a high level of dependence on fossil fuels and a need for substantial capital investments to transition to less carbon intensive generation.¹⁴¹

¹³⁹ Perry Testimony, p. 9.

¹⁴⁰ Regulatory Research Associates, “Major energy rate case decision in the US: January – June 2024,” July 29, 2024 (CONFIDENTIAL)

¹⁴¹ Revised Exhibit A-14, Schedule D5.18.

III. Riskiness of DTE Electric

Q48. What criticisms do Staff or Intervenors make regarding your conclusion of ROE for DTE Electric?

A48. Mr. Walters and Mr. Bandyk disagree with my finding that DTE Electric is of higher risk than the sample companies. Mr. Coppola finds that there is no ratings downgrade risk associated with a lower ROE, while Ms. Perry and Mr. Bandyk focus on regulatory mechanisms in Michigan as well as the load and generation composition.

Q49. How do you respond?

A49. Mr. Coppola opines that “[i]t is unlikely that a downgrade would occur simply due to a slightly lower ROE rate.”¹⁴² While that may be true, the credit rating is a reflection of creditworthiness or default risk and not a measure of whether the Company is receiving a “fair return.”

Mr. Walters also looks to credit agencies views, which as noted above pertain to the impact on credit worthiness, not on the risk to shareholders. In this regard, I note that Mr. Walters fails to consider the fact that DTE Electric has substantially more coal generation than the sample - - according to Value Line approximately twice that of the average sample company. The magnitude of DTE Electric’s reliance on coal means it has to invest in non-emitting resources to transition to a lower carbon environment. This inherently means a higher capital spend, which is associated with higher operating leverage and during the construction period the potential for risks associated with the build.

Ms. Perry refers to the reduced risk associated with Michigan’s regulatory framework “including the (i) use of a projected test year ..., (ii) inclusion of CWIP in rate base, (iii) and the IRM currently approved for 2024 and 2025 ...”¹⁴³ While this is true, it is also true that such mechanisms and other

¹⁴² Coppola Testimony, p. 96.

¹⁴³ Perry Testimony, p. 9.

1 regulatory mechanisms are common in the electric utility industry, as
2 demonstated in Exhibit A-14, D5.19, which shows that a large number of
3 electric utilities have a forward test year and many have some sort of delivery
4 infrastructure recovery mechanism as well as recovery of CWIP.¹⁴⁴ Thus, these
5 do not seem to be distinguishing factors.

6 Mr. Bandyk also notes the regulatory mechanisms in Michigan (forward test
7 year, CWIP in rate base) and comments that “‘many’ but not all of the proxy
8 group companies” have those regulatory mechanisms.¹⁴⁵ While that is true, it is
9 also true that DTE Electric does not have all the mechanisms that other sample
10 companies have – the most meaningful of which is the decoupling mechanism.
11 As for the fact that DTE Electric has a slightly lower industrial load, I note that
12 the Michigan load is relatively concentrated in the automotive sector and thus
13 susceptible to changes in one industry. I also note that Michigan saw a larger
14 increase in unemployment during COVID-19 than did the U.S. on average.
15 These facts indicate that the industrial load is relatively concentrated and could
16 be volatile.¹⁴⁶ I therefore do not believe that a 2 percent lower than average
17 industrial load¹⁴⁷ materially impacts DTE Electric’s business risk relative to the
18 comparable companies. Lastly, I agree that classic cost of equity estimation
19 models measure the systematic risk and not business risk, business risk can be
20 used to place a company within a reasonable range. In addition, it is clear that
21 factors such as operating leverage,¹⁴⁸ impact the volatility of returns and hence
22 the estimated cost of equity.

23 In summary, there is nothing in discussion of business risk from Intervenor
24 that affect my recommendation.

¹⁴⁴ I do not have data on the availability of CWIP in rate base.

¹⁴⁵ Bandyk Testimony, p. 13.

¹⁴⁶ IBISWorld, “Michigan – State Economic Profile: Statistics, economic information and rankings for the Great Lakes State. [Michigan Economic Trends, Stats & Rankings | IBISWorld](#)

¹⁴⁷ Bandyk Testimony, p. 13.

¹⁴⁸ See, for example, Brealey, Myers and Allen (2017), “Principles of Corporate Finance,” 12th edition, pp. 257-258.

1 **Q50. Does the fact that there are issues in Staff's and Intervenors' testimonies**
2 **you have not addressed mean that you agree?**

3 A50. No.

4 **Q51. Does this conclude your rebuttal testimony?**

5 A51. Yes.

APPENDIX: ECAPM

Q52. What critiques do MPSC Staff and the Intervenors make regarding your use of the ECAPM methodology?

A52. Mr. Walters argues that use of adjusted betas in the ECAPM methodology is not appropriate, and the use of adjusted betas “double counts” increase impact of the adjustment.¹⁴⁹ Messrs. Ufolla, Coppola Bandyk are also opposed to the ECAPM with Mr. Bandyk arguing it is not common in regulatory proceedings.¹⁵⁰ However, neither witness spend substantial time discussing the method, so my responses shall be brief.

Q53. Do you agree with Mr. Walters that the simultaneous use of the ECAPM and adjusted betas biases the ROE estimates?

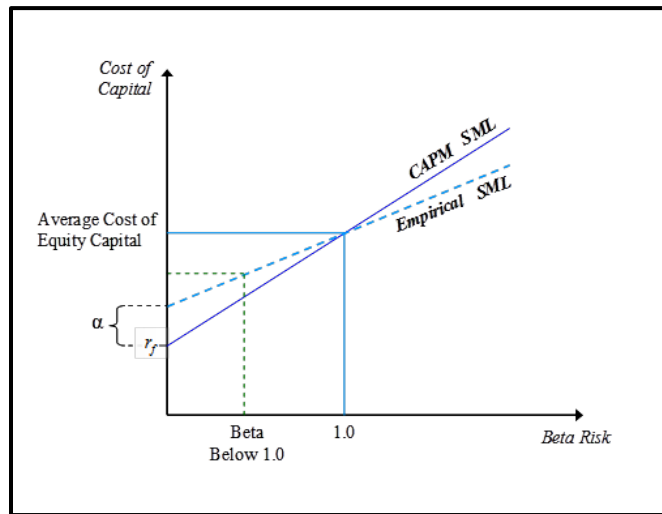
A53. Mr. Walters is concerned that I use ECAPM in combination with Value Line betas, which are Blume adjusted.¹⁵¹ He believes the adjustment is inappropriate. However, the Blume adjustment and the ECAPM are two fundamentally different and complementary adjustments, and both are well supported by the academic literature. The reason for these necessary adjustments can be shown by reference to Figure 4 below, which illustrates the empirical security market line (“SML”). The adjustment to beta corrects the estimate of the relative risk of the company, which is measured along the horizontal axis of the SML. The ECAPM adjusts the risk-return tradeoff (i.e., the slope) in the SML, which is on the vertical axis. In other words, the expected return (measured on the vertical axis) for a given level of risk (measured on the horizontal axis) is different from the predictions of the theoretical CAPM. Getting the relative risk of the investment correct does not adjust for the slope of the SML, nor does adjusting the slope correct for errors in the estimation of relative risk.

¹⁴⁹ Walters Testimony, p. 62.

¹⁵⁰ Ufolla Testimony, p. 17, Coppola Testimony, p. 89, Bandyk Testimony, p. 17.

¹⁵¹ Walters Testimony, pp. 70-71.

FIGURE 4: THE EMPIRICAL SECURITIES MARKET LINE



Importantly, the Blume adjustment has the effect of moving the beta along the x-axis whereas the ECAPM is using the y-axis. The Value Line relied upon method to make betas more precise was developed by Professor Blume.¹⁵² As shown in Professor Blume's paper, it is possible to apply a consistent adjustment procedure to historical betas that increased the accuracy in forecasting realized betas. Essentially, Professor Blume's adjustment transforms a historical beta into a better estimate of expected future beta. It is this expected "true" beta that drives investors' expected returns according to the CAPM.

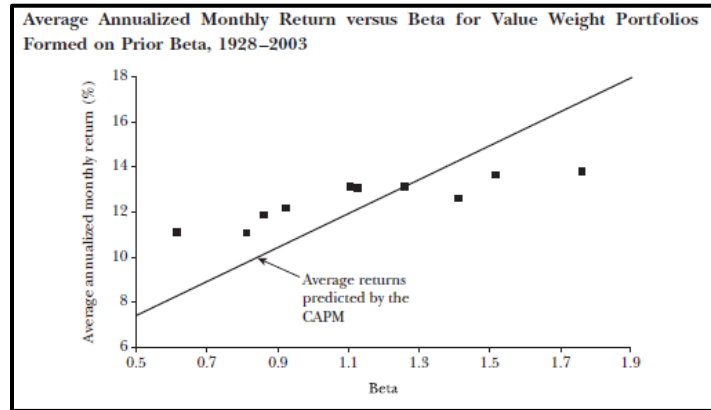
The backward-looking empirical tests of the CAPM that gave rise to the ECAPM did not suffer from bias in the measurement of betas as do a forward-looking use. Researchers plotted realized stock portfolio returns against betas measured over *the same time period* to produce plots such as Figure 5. below, which comes from the 2004 paper by Professors Eugene Fama and Kenneth French.¹⁵³ The fact that betas and returns were measured contemporaneously means that the betas used in the tests were already the best possible measure of the "true" systematic risk over the relevant time period. In other words, no adjustments were needed for these

¹⁵² Blume, Marshall E. (1971), "On the Assessment of Risk," The Journal of Finance, 26, p. 1-10.

¹⁵³ Fama, Eugene F. & French, Kenneth R. (2004), "The Capital Asset Pricing Model: Theory and Evidence," Journal of Economic Perspectives, 18(3), p. 25-46.

betas. Despite this, researchers observed that the risk-return trade-off predicted by the CAPM was too steep to accurately explain the realized returns. As explained above the ECAPM explicitly corrects for this empirical observation.

FIGURE 5: EVIDENCE FROM EMPIRICAL TESTS OF THE CAPM¹⁵⁴



Q54. Did the empirical tests that gave rise to the ECAPM use raw betas in their analyses?

A54. Yes, however, this is simply because the researchers were able to measure raw betas and realized returns from the same historical period. In other words, no adjustment to the raw beta was necessary to evaluate the market return realized for the same historical period – that is different from using betas to determine the cost of equity for future periods. Hence, the raw betas they measured accurately captured the systematic risk that impacted the returns they measured. In a sense, the measured betas and realized returns were already contemporaneous in the tests of the CAPM.

This is explicit in the article by Litzenberger et al.,¹⁵⁵ who explain (on page 376) that the estimate of “alpha” they obtain when using historical (i.e., “raw”) betas is a linear combination of the alpha that would be obtained with a perfect estimate of “true” beta and the weighting factor employed in the Blume “global

¹⁵⁴ Id., p. 33.

¹⁵⁵ Robert Litzenberger, Krishna Ramaswamy and Howard Sosin, “On the CAPM Approach to the Estimation of a Public Utility’s Cost of Equity Capital,” *Journal of Finance*, vol 35, 1979.

adjustment” procedure, which they describe with the equation $\beta_i = \omega\beta_{i(historical)} + (1 - \omega)1$. Using the equations that the authors present along with their results presented in the “Raw Betas” panel of Table 1 (on page 380 of the paper), it is possible to derive the estimate of alpha implied for use of Blume adjusted beta with $\omega=0.67$:

$$a = a' - b' \left(\frac{1 - \omega}{\omega} \right) = 0.326 - 0.330 \left(\frac{0.33}{0.67} \right) = 0.163$$

In other words, the results of Litzenberger et. al.’s study is consistent with an ECAPM alpha factor of approximately 2.0 percent when applying Blume-adjusted betas.¹⁵⁶ In that light my use of an alpha factor of 1.5 percent is conservative.

Q55. How about the argument that the ECAPM is not widely used in regulatory proceedings?

A55. First, I believe the Commission should be presented with the best possible analysis regardless of whether the analysis is “widely used” by regulators. Second, there certainly are regulatory commissions that have adopted the ECAPM methodology. Examples include the Mississippi Public Service Commission¹⁵⁷ and the New York State Public Service Commission.¹⁵⁸ Importantly, all of these regulators rely on the ECAPM in conjunction with adjusted betas and the California Public Utilities Commission did not distinguish between CAPM and ECAPM when reporting results.¹⁵⁹ This list is not exhaustive as many commissions review the evidence before them, based on which they decide on an allowed return without explicitly accepting or rejecting any specific methodology.

¹⁵⁶ Since Litzenberger, et. al. used monthly return data, their monthly alpha estimate of 0.163% corresponds to $(1.00163)^{12} - 1 = 1.97\%$ when annualized.

¹⁵⁷ Mississippi Power, PEP-5A, p. 24.

¹⁵⁸ NY PSC Case 24-E-0060, Staff Finance Panel Testimony, May 2024, p. 83-84.

¹⁵⁹ California Public Utilities Commission, “Decision 19-12-056,” December 19, 2019.

1 **Q56. What do you conclude regarding the ECAPM?**

2 A56. For the reasons discussed above, the ECAPM has merit and there is no double-
3 counting in using adjusted betas in the ECAPM. Not only is the ECAPM of
4 merit, but failing to consider the results will downward bias the results by a
5 minimal amount.

1 JUDGE WALLACE: Please go ahead.

2 MR. JANISZEWSKI: Thank you, your Honor.

3 Next, the Company moves to bind into the record the
4 Qualifications and Direct Testimony of Timothy J.
5 Lepczyk, consisting of a cover sheet and 18 pages of
6 questions and answers. The Company also moves for the
7 admission of the following 12 direct exhibits sponsored
8 by Mr. Lepczyk, marked as Exhibit A-1 Schedule A2,
9 Exhibit A-4 Schedule D2, Exhibit A-4 Schedule D3, Exhibit
10 A-4 Schedule D4, Exhibit A-4 Schedule D5, Exhibit A-11
11 Schedule A2, Exhibit A-14 Schedule D1.1, Exhibit A-14
12 Schedule D2, Exhibit A-14 Schedule D3, Exhibit A-14
13 Schedule D4, Exhibit A-18 Schedule H1, Exhibit A-18
14 Schedule H2. The Company also moves to bind into the
15 record the Rebuttal Testimony of Timothy J. Lepczyk,
16 consisting of a cover sheet and four pages of questions
17 and answers, and the Company moves for the admission of
18 the one rebuttal exhibit sponsored by Mr. Lepczyk, marked
19 as Exhibit A-45 Schedule JJ1. And there are no changes
20 to Mr. Lepczyk's testimony or exhibits.

21 JUDGE WALLACE: Thank you,
22 Mr. Janiszewski. Is there any objection to binding in
23 the direct and rebuttal testimony of Lepczyk?

24 Hearing none, the testimony is bound in.

25 Is there any objection to the exhibits

1 and associated schedules sponsored by Mr. Lepczyk?

2 All right. We will admit those at the
3 end.

4 (Testimony bound in.)

5 - - -

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
DIRECT TESTIMONY
OF
TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. LEPCZYK

Line
No.

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

2 A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy
3 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4 Energy Corporate Services, LLC as Assistant Treasurer and Director of Corporate
5 Finance, Insurance and Development.

6

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

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

9

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

11 A3. I graduated from Georgetown University in 2004 with a Bachelor of Business
12 Administration degree, with a concentration in International Business. In 2008, I
13 graduated with my MBA from the University of Michigan, with a focus in Finance
14 and Corporate Strategy.

15

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

17 A4. I began my employment with Ford Motor Company in the summer of 2004 as a
18 financial analyst within that company's Dearborn Stamping facility. In 2006, I left
19 to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company,
20 a management consultancy, where I focused on the automotive and industrial
21 sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE
22 Energy.

23

24 In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where
25 I was the lead analyst for various projects and studies primarily relating to the Gas

**Line
No.**

1 Storage and Pipeline business. In 2014, I formally accepted a position within the
2 Gas Storage and Pipeline team as Manager in their strategy group where I was
3 responsible for various economic analyses (e.g., natural gas supply and demand
4 fundamentals) and for assessing potential new acquisition opportunities. In 2016, I
5 accepted the position of Manager for the Corporate Development team where I was
6 responsible for managing DTE Energy's capital investment process and various
7 valuation processes (for example, DTE Energy's annual Goodwill impairment
8 assessment). In addition, I led broader strategy initiatives including the analysis,
9 which ultimately led to our decision to spin off the Midstream business segment.

10

11 In 2021, I accepted my current position, Assistant Treasurer and Director of
12 Corporate Finance, Insurance and Development.

13

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

15 A5. I am responsible for assisting the Treasurer in managing the capital needs of the
16 Company. These responsibilities include managing corporate liquidity and
17 financing activities such as the raising of both equity capital and capital markets
18 debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist
19 in maintaining relationships with the commercial and investment banking
20 community, interact with the rating agencies, and execute corporate financial
21 policies, particularly in the areas of balance sheet management, debt issuances, and
22 agency ratings. In addition, I manage the Company's capital investment approval
23 and review process along with managing the Company's property and liability
24 insurance function.

Line
No.

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

3 A6. Yes, I have. I have sponsored testimony in the following cases:

4 U-20836 DTE Electric 2022 General Rate Case

5 U-21193 DTE Electric 2022 Integrated Resource Plan

6 U-21338 DTE Electric 2023 Securitization

7 U-21291 DTE Gas 2024 General Rate Case

8 U-21297 DTE Electric 2023 General Rate Case

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 support DTE Electric's projected capital
4 structure and the cost of its long- and short-term debt to be used in the determination
5 of DTE Electric's overall rate of return in this proceeding.

6

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

8 A8. My testimony is organized as follows:

9 I. Summary of Recommendations

10 II. Development of Capital Structure

11 III. Development of Cost Rates

12 IV. Securitization

13 V. Summary and Conclusions

14

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

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

17	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
18	A-1	A2	Historical Financial Metrics
19	A-4	D2	Historical Cost of Long-Term Debt
20	A-4	D3	Historical Cost of Short-Term Debt
21	A-4	D4	Historical Cost of Preferred and Preference Stock
22	A-4	D5	Historical Cost of Common Shareholders' Equity
23	A-11	A2	Projected Financial Metrics
24	A-14	D1.1	Peer Group Common Equity
25	A-14	D2	Projected Cost of Long-Term Debt

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1	A-14	D3	Projected Cost of Short-Term Debt
2	A-14	D4	Projected Cost of Preferred and Preference Stock
3	A-18	H1	Current and Historical Credit Ratings
4	A-18	H2	Recent Utility Corporate Bond Issuances

5

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

7 A10. Yes, they were.

8

9 **I. SUMMARY OF RECOMMENDATIONS**

10 **Q11. What permanent capital structure are you recommending for the projected**
 11 **test year to be utilized in determining the overall rate of return calculation for**
 12 **DTE Electric?**

13 A11. I am recommending a projected permanent capital structure of 50% long-term debt
 14 and 50% common equity. Permanent capital is long-term perpetual capital.
 15 Common equity, preferred stock and long-term debt are sources of permanent
 16 capital. Since the Company does not have any preferred stock, I am recommending
 17 the permanent capital structure to be made up of 50% long-term debt and 50%
 18 common equity. This permanent capital structure is reflected in DTE Electric's
 19 projected permanent capital structure as of December 31, 2025, as shown in Exhibit
 20 A-14, Schedule D1, which is supported by Company Witness Vangilder. This
 21 capital structure is necessitated by the business and financial risks confronting DTE
 22 Electric, which I will discuss in greater detail later in my testimony.

23

24 **Q12. What is your forecast for DTE Electric's cost of long-term debt, short-term**
 25 **debt, and preferred stock for the 12-month period ending December 31, 2025?**

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1 A12. I am forecasting 4.24% for the cost of DTE Electric's long-term debt, and 5.76%
2 for the cost of DTE Electric's short-term debt. The Company does not have
3 preferred stock, and therefore it has no cost rate. Exhibit A-14, Schedule D2
4 supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports the
5 cost rate for short-term debt.

6

7 **II. DEVELOPMENT OF CAPITAL STRUCTURE**

8 **Q13. What do you mean by capital structure?**

9 A13. A company's capital structure includes the amount of equity and debt necessary to
10 support the operations of its business and is defined differently by regulators,
11 finance professionals, and rating agencies. Total regulatory capital structure
12 typically includes long-term debt, short-term debt, preferred stock, common equity,
13 deferred taxes, deferred job development investment tax credits, and deferred
14 investment tax credits. Permanent capital structure includes only long-term debt
15 and equity. Rating agencies calculate a company's capital structure using short-
16 term debt, long-term debt, preferred stock, common equity, and other adjustments.
17 The rating agencies adjust debt to include items like capital and operating leases,
18 unfunded pension liabilities, power purchase agreements, and asset retirement
19 obligations.

20

21 **Q14. Why is a sound capital structure important?**

22 A14. It is important to have a financially sound capital structure in order to ensure that a
23 company can obtain needed capital. A sound capital structure produces capital
24 costs that are reasonable and equitable. Also, it is important that the overall return
25 on capital be sufficient to assure financial confidence in a firm and to allow it to

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1 raise the funds that are necessary to operate its business at reasonable costs and
2 terms. A sound capital structure is in the best interests of the customers as it ensures
3 the continued viability of the company.

4

5 **Q15. How does risk affect a firm's capital structure?**

6 A15. In general, a firm such as DTE Electric faces two types of risk: business risk and
7 financial risk. Business risk is a result of systemic and non-systemic risk. Systemic
8 risks are broad economic risks faced by all firms. Non-systemic risks are risks
9 specifically identified as those faced by the individual firm. Financial risk is the
10 risk that common equity shareholders face to the extent that a firm issues debt to
11 finance real assets. Debtholders (also known as bondholders) have priority over
12 equity shareholders in the event of corporate bankruptcy. Thus, the greater the
13 amount of debt held by a firm, the greater the risk to equity shareholders. It is
14 essential that a firm recognizes the dynamics of these risks and adjusts its
15 underlying debt and equity components to produce a sound capital structure.

16

17 **Q16. How does a company's capital structure impact its ability to attract capital?**

18 A16. Having a weak or highly leveraged capital structure may lead to higher required
19 returns on equity and a higher cost of debt. It also can impact the company's ability
20 to obtain capital. For example, a company with a highly leveraged capital structure
21 may lose its investment grade rating from the rating agencies. Non-investment
22 grade companies have a limited investor base and a more limited access to capital
23 than investment grade companies. Moreover, during periods of diminished capital
24 liquidity, even investment grade companies can have limited access to new capital
25 sources. It is important to consider how extreme market reactions to singular events

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1 impact how easily capital will be able to be accessed during the future test period
2 should an unforeseen market shock occur. Furthermore, rating agencies allow little
3 or no time for a company to correct and improve its capital structure before
4 lowering its credit rating. Conversely, companies must be proactive to target and
5 achieve the midpoint of the range of rating agency financial metrics to have a better
6 chance to maintain current ratings.

7

8 **Q17. Will higher debt levels in a capital structure affect the cost of debt?**

9 A17. Yes. The cost of debt increases as more debt is added to the capital structure.
10 Further, higher debt levels can increase the risk of a downgrade by the rating
11 agencies. A lower credit rating means greater credit risk such that investors will
12 require a higher return to invest in a company, thereby increasing the cost of debt
13 for that company.

14

15 **Q18. For DTE Electric's defined projected test year, what capital structure are you**
16 **recommending for DTE Electric in the instant case?**

17 A18. For the projected test year, the permanent capital structure that I am recommending
18 includes long-term debt and equity as shown on Exhibit A-14, Schedule D1, that is
19 supported by Witness Vangilder. Within this regulatory capital structure, I am
20 recommending a projected test year permanent capital structure that has 50% long-
21 term debt and 50% common equity. This is the same permanent capital structure
22 authorized by the Commission in the last general rate case, Case No. U-21297.

23

24 **Q19. Does the Company believe that a 50/50 capital structure is the optimal capital**
25 **structure for DTE Electric?**

Line
No.

1 A19. No. To reduce the number of contested positions in the instant case, the Company
2 is using the structure authorized in the December 1, 2023 order in Case No. U-
3 21297. However, as the Company has argued in past rate cases, it believes the more
4 appropriate capital structure for DTE Electric is closer to that of its peers. Exhibit
5 A-14, Schedule D1.1 shows DTE Electric peers having a capital structure made up
6 of 48% long-term debt and 52% common equity. A 50% equity level gives the
7 Company less protection in the event of an unforeseen market event and may
8 impact DTE Electric's ability to access capital during the future test period should
9 an unforeseen market shock occur.

10

11 **Q20. Is the proposed ratio of 50% common equity to total permanent capitalization**
12 **in line with DTE Electric's peers?**

13 A20. No. The common equity ratio requested in the instant case is lower than that of the
14 Company's peers. As shown on Exhibit A-14 Schedule D1.1, the average equity
15 ratio for DTE Electric peers was approximately 52%. DTE Electric's targeted 50%
16 equity ratio is a reasonable level given that the average ratio of the peer group is
17 higher at 52%. The data was obtained from S&P Global Market Intelligence (SNL)
18 for the most recent fiscal year available per peer company. DTE Electric believes
19 its requested 50% is reasonable and below the equity ratio of its peers across the
20 country and within Michigan.

21

22 **Q21. Does the intense capital investment program contribute to the need for a**
23 **higher level of equity in general within the capital structure?**

24 A21. Yes, it is imperative that DTE Electric be viewed as a financially sound firm with
25 a solid investment grade rating to ensure the reasonableness and competitiveness

Line
No.

1 of capital costs. DTE Electric will be financing and funding over \$7.9 billion of
2 electric capital expenditures for the period January 2023 through December 2025
3 (see Exhibit A-12 Schedule B5). In a period of intense capital investment, a sound
4 capital structure and a favorable regulatory environment are essential to maintain
5 the financial well-being of the Company. Should the Company face any unforeseen
6 or negative impacts to its financial health, a higher equity balance may be needed.
7 The common equity balance and equity ratio projected for the test year in the instant
8 case will hopefully enable the Company to maintain strong credit ratings and
9 withstand any shocks in the financial markets, thereby ensuring a smooth
10 implementation of its capital expenditure program.

11

12 **Q22. Is DTE Electric committed to maintaining a 50% equity ratio in its capital**
13 **structure?**

14 A22. Yes. At December 31, 2022, DTE Electric's equity ratio was 50%. DTE Electric
15 is committed to maintaining a 50% equity ratio and has demonstrated its
16 commitment to its targeted equity ratio by receiving equity infusions from DTE
17 Energy. DTE Energy has made reasonable efforts to strengthen DTE Electric's
18 credit quality by infusing over \$2.3 billion of common equity from 2018-2022.
19 DTE Electric has received equity infusions totaling \$760 million in 2023 and will
20 infuse the amounts necessary in future years to maintain a 50% common equity
21 ratio.

22

23 **III. DEVELOPMENT OF COST RATES**

24 **Q23. What were DTE Electric's historical financial and ratemaking metrics from**
25 **2018 through 2022?**

Line
No.

1 A23. DTE Electric's historical financial and ratemaking metrics for each of the previous
2 five years (2018 through 2022) are detailed in Exhibit A-1, Schedule A2. The
3 historical financial calculations include year-end financial metrics and are
4 calculated on a financial basis from DTE Electric's financial reports. The historical
5 ratemaking metrics include year-end financial metrics and are calculated from DTE
6 Electric's annual regulatory filings.

7
8 **Q24. What is the cost of long-term debt outstanding at December 31, 2022?**

9 A24. Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding at
10 December 31, 2022. As shown in the exhibit and schedule, the cost of long-term
11 debt also includes agent's fees, commissions, and financing expenses and is
12 calculated on the net proceeds to the Company. The weighted average cost of debt
13 is computed based on the total annual costs to the Company divided by the total
14 principal amount outstanding at year-end. The cost of long-term debt at December
15 31, 2022 was 3.77%.

16
17 **Q25. What is the cost of short-term debt outstanding at December 31, 2022?**

18 A25. The cost of short-term borrowings for the 13-month period ended December 31,
19 2022 was 2.75%. The cost of short-term debt consists of the 1) interest rate on short-
20 term borrowings, and 2) credit facility fees associated with the credit agreements
21 necessary for the issuance of short-term debt. See Exhibit A-4, Schedule D3.

22
23 **Q26. What was the approved cost of equity as of December 31, 2022?**

Line
No.

1 A26. DTE Electric's authorized cost of common shareholders' equity as of December
2 31, 2022 was 9.9% and was approved in Case No. U-20836. DTE Electric does not
3 have any preferred stock. See Exhibit A-4, Schedules D4 and D5.

4

5 **Q27. What does DTE Electric project its financial metrics to be in the projected test**
6 **year?**

7 A27. DTE Electric's forecasted ratemaking metrics are available in Exhibit A-11,
8 Schedule A2. Forecasted calculations include metrics for the fully projected test
9 year. The forecasted ratemaking metrics for the projected test year are to be
10 reported assuming (i) full rate relief as requested, and (ii) zero rate relief.

11

12 **Q28. What is the purpose of Exhibit A-14, Schedule D2?**

13 A28. The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected
14 weighted average long-term debt costs as of December 31, 2025. Starting with the
15 actual December 31, 2022 long-term debt outstanding, any known and measurable
16 changes for each year were made to arrive at the projected balance as of December
17 31, 2025. Known and measurable changes that have occurred or are projected to
18 occur from January 1, 2023 through December 31, 2025 include:

Line
No.

1

Table 1 Issuances and Redemptions

Long-Term Debt Activity	Amount (\$000)	Date	Interest Rate
Issuance	600,000	Mar-23	5.20%
Issuance	600,000	Mar-23	5.40%
Issuance	100,000	Jun-23	3.88%
Redemption	(102,000)	Sep-23	4.31%
Redemption	(100,000)	Oct-23	5.19%
Redemption	(300,000)	Dec-23	3.65%
Issuance	575,000	Mar-24	5.65%
Redemption	(100,000)	Mar-24	3.65%
Issuance	800,000	Mar-25	5.62%
Redemption	(350,000)	Mar-25	3.38%
Issuance	500,000	Jul-25	5.62%
Net change in debt	2,223,000		

2

3 The 2024 and 2025 debt issuances are assumed to be 30-year fixed rate bonds with
4 an interest rate of 5.65% and 5.62%, respectively. The interest rate for the debt
5 issuances is based on forward 30-year Treasury rates and adding a spread of 148
6 basis points which is the spread on the Company's last 30-year debt issuance.
7 Including the planned long-term debt issuance, the weighted average long-term
8 debt cost as of December 31, 2025 is projected to be 4.24%.

9

10 **Q29. Why did you use long-term debt cost on a net proceeds basis?**

11 A29. The actual costs would be understated if the net proceeds were not used in the base
12 calculation. The net proceeds methodology accounts for underwriters'
13 compensation and other financing expenses and is shown on Exhibit A-14,
14 Schedule D2. A portion of any amount financed is used to fund these costs, such
15 that the Company has access to less than the full amount financed. As a result,

Line
No.

1 these fees and expenses are shown as a reduction in proceeds from the issuance of
2 new securities, thereby increasing the effective cost of the issuance above the stated
3 coupon rate.

4

5 **Q30. How did you determine the interest rate on short-term debt on Exhibit A-14,**
6 **Schedule D3?**

7 A30. The total cost of short-term debt is comprised of the interest rate on the short-term
8 debt plus associated facility fees. Supporting credit facilities are required by the
9 rating agencies and investors for DTE Electric to issue commercial paper. These
10 facilities have costs associated with them. The interest rate on the short-term debt
11 was determined by adding 20 basis points (bps) to the 1-month short-term index.
12 Due to the uncertainty of interest rates and Fed Fund rate changes, the Company is
13 using the short-term debt index and short-term debt rate in effect as of December
14 2023. Interest rates have been very volatile recently with market uncertainty around
15 when and if the Fed will lower the Fed Funds rate. Given this unpredictability, the
16 Company feels it is prudent to use the current and known rate. A spread of 20 bps
17 was added to the index because that is the current spread on DTE Electric's
18 commercial paper issuances. See Exhibit A-14, Schedule D3.

19

20 The current 1-month short-term index is 5.31%. Adding the spread of 20 bps to the
21 index brings the interest rate on short-term borrowings to a total of 5.51%. The
22 cost of the facility fees for the 12-month period ending December 31, 2025, is \$1.3
23 million. This cost was divided by the average outstanding short-term debt balance
24 of \$509 million and equates to 0.25% of the cost of short-term debt. Adding the

Line
No.

1 interest rate on short-term debt of 5.51% to the facility fee cost of 0.25%, results in
2 the total cost of short-term debt of 5.76%.

3

4 **Q31. What is the purpose of Exhibit A-14, Schedule D4?**

5 A31. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferred
6 or preference stock during the projected test period.

7

8 **Q32. What are the Company's current and historical credit ratings?**

9 A32. Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and
10 historical credit ratings, along with associated rating agency outlooks, for the
11 previous five years as published by Standard & Poor's (S&P), Moody's Investors
12 Service (Moody's), and Fitch Ratings. The credit ratings include senior unsecured
13 debt, senior secured debt, and commercial paper ratings.

14

15 **Q33. Have there been recent public utility bond issuances?**

16 A33. Yes. I have provided details of public utility bond issuances for the three-month
17 period prior to, through the three-month period after, each of DTE Electric's long-
18 term debt offerings issued during the 24 months prior to December of 2023. This
19 summary includes the offer date, issuing company, type of offering (either secured
20 or unsecured), Moody's and S&P credit ratings, maturity, tenor, amount of offering,
21 coupon, and issue spread. See Exhibit A-18, Schedule H2.

22

23 **IV. SECURITIZATION**

24 **Q34. Does the Company intend to securitize additional regulatory assets?**

Line
No.

1 A34. Yes. On June 22, 2023, in Case No. U-21338, the Commission approved DTE
2 Electric's application to issue securitization bonds for up to \$601.6 million in costs
3 associated with the closure of the Trenton Channel and St. Clair coal-fired
4 generation plants. The securitization financing was completed in November of
5 2023. The Company is planning a future securitization of the tree trim regulatory
6 assets once the balance is large enough to make a financing feasible.

7

8 **Q35. How has the tree trim surge regulatory asset been financed in prior rate cases?**

9 A35. On May 2, 2019, the Commission issued its order in Case No. U-20162 whereby
10 the Company was authorized a return on the tree trim surge regulatory asset at the
11 short-term debt cost rate of 3.56%. (p. 80). In Case No. U-20561, Case No. U-
12 20836, and Case No. U-21297 the return on tree trim surge regulatory asset was
13 calculated at the authorized short-term debt rate.

14

15 **Q36. What does the Company believe is the appropriate financing rate for tree-trim**
16 **assets?**

17 A36. Given the temporary status, defined in Case No. U-20162, of the tree trim surge
18 regulatory asset, the Company did not pursue financing with permanent long-term
19 debt and equity capital, but rather financed with short-term working capital
20 including short-term debt. Thus, this was matching the financing costs with the
21 return the Company was earning on the regulatory asset. In securitization Case No.
22 U-21015 and Case No. U-21338, the Commission considered the regulatory asset
23 to have been financed with permanent capital and specified that proceeds of the
24 securitization should be used for the repayment of long-term debt and equity.
25 Consistent with that financing order, the Company's position is that any future tree

Line
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1 trim surge regulatory asset amounts should be treated as being financed with
2 permanent long-term debt and equity capital and receive the respective return.

3

4 **Q37. How does the Company propose to treat the tree trim surge regulatory asset**
5 **in this instant case?**

6 A37. In Case No. U-21297, the Company reiterated its position that any future tree
7 trimming surge expenditures be financed through the issuance of long-term debt
8 and equity until the time the Company can execute a securitization financing for
9 these amounts., I have directed Witness Vangilder to calculate the return on
10 projected tree trim surge regulatory assets using the cost of permanent long-term
11 debt and equity capital.

12

13 **V. SUMMARY AND CONCLUSIONS**

14 **Q38. Can you summarize your recommendation and conclusions?**

15 A38. Due to the financial and business risks faced by the Company, a projected
16 permanent capital structure of 50% long-term debt and 50% common equity is
17 reasonable and prudent. DTE Energy has taken reasonable actions to strengthen
18 DTE Electric's credit quality and has done so by infusing over \$2.3 billion of
19 common equity from 2018 through 2022 and will continue to do so as needed. The
20 plan calls for additional equity infusions and retained earnings growth through the
21 projected test period in the amount necessary to maintain the Company at no less
22 than a ratio of 50% equity to permanent capital at December 31, 2025. For the
23 projected year, the cost of short-term debt is projected to be 5.76%, and the cost of
24 long-term debt is projected to be 4.24%. I believe these expenses and measures are
25 reasonable, prudent and necessary.

Line
No.

1 **Q39. Does this complete your direct testimony?**

2 A39. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF TIMOTHY J. LEPCZYK

Line
No.

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

2 A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy
3 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4 Energy Corporate Services, LLC as Assistant Treasurer and Director of Corporate
5 Finance, Insurance and Development.

6
7 **Q2. Are you the same Timothy J. Lepczyk who previously offered testimony in this**
8 **proceeding?**

9 A2. Yes, I am.

10

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

12 A3. The purpose of my testimony is to rebut the arguments made by Michigan Public
13 Service Commission Staff (Staff) Witness Joseph E. Ufolla and Witness Shannon
14 Rueckert, Attorney General (AG) Witness Sebastian Coppola, Association of
15 Businesses Advocating Tariff Equity (ABATE) Witness Christopher C. Walters,
16 and Attorney General (AG), Michigan Environmental Council (MEC), and Natural
17 Resources Defense Council (NRDC), collectively referred to as “AG-MN” Witness
18 Paul Alvarez.

19

20 The absence of a discussion of other matters in my rebuttal testimony should not
21 be taken as an indication that I agree with other aspects of any Staff or intervenor
22 testimony.

23

24 **Q4. Are you sponsoring any rebuttal exhibits?**

25 A4. I am sponsoring the following rebuttal exhibit:

T. J. LEPCZYK

U-21534

Line
No.

Line No.	Exhibit	Schedule	Description
1			
2	A-45	JJ1	Updated Projected Cost of Long-term Debt
3			

4 **Q5. Was this exhibit prepared by you or under your direction?**

5 A5. Yes, it was.

6

7 **Capital Structure**

8 **Q6. Do you agree with ABATE Witness Walters' assertion on page 25 that DTE**
 9 **Electric proposes an equity ratio of 53.5%?**

10 A6. No. Consistent with the relief requested in DTE Electric's Application in this rate
 11 case, pages TJL-8 Line 15 through TJL-9 Line 20 of my direct testimony, proposed
 12 an equity ratio of 50%. We could not find evidence of the Company requesting a
 13 proposed equity ratio of 53.5% and assume this is an error in Mr. Walters'
 14 testimony. However, contrary to Witness Walters' assertion that DTE Electric's
 15 proposed equity ratio significantly exceeds the equity ratio for the proxy group,
 16 Exhibit A-14, Schedule D1.1, shows that the average equity ratio for DTE Electric's
 17 peers is approximately 52%. DTE Electric believes its requested 50% equity ratio
 18 is reasonable and lower than the average equity ratio of its peers.

19

20 **Development of Cost Rates**

21 **Q7. Do you agree with Staff Witness Ufolla's recommendation on page 22 of his**
 22 **direct testimony for a Long-Term Debt rate of 4.21%?**

23 A7. No. Based upon an updated rate curve as of August 6, 2024, the Company now
 24 calculates a Long-Term Debt issuance rate of 5.53% for 2025 (as compared against
 25 a long-term debt rate for the projected 2025 issuance of 5.62% in my original

T. J. LEPCZYK

U-21534

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1 testimony and 5.33% as calculated by Witness Ufolla), based on an average
2 projected 30-year treasury rate of 4.05% plus a 148 bps spread. With these updated
3 projected 2025 issuances and actual 2024 issuances, the weighted average long-
4 term debt cost as of December 31, 2025, approximates the projected 4.24%
5 calculated in my original testimony and shown on Exhibit A-45 Schedule JJ1.

6

7 **Q8. Do you agree with Staff Witness Ufolla's recommendation on page 22 of his**
8 **direct testimony for a Short-Term Debt rate of 4.96%?**

9 A8. No. Given the potential for "higher for longer" interest rates, as well as the
10 consistent overly-optimistic forecasts regarding the proximity of Fed rate cuts, we
11 believe the current short-term cost of debt is a more appropriate metric than the
12 market's forecast rate. The actual average borrowing rate for DTE Electric in July
13 2024 was 5.48% (this figure includes DTE Electric's actual interest rate spread).
14 The cost of credit facility fees adds an incremental 0.25% for a total short-term debt
15 rate of 5.73%. Due to the continued market volatility, the Company feels it is
16 reasonable and prudent to use the July 2024 short-term cost of debt rate of 5.73%.

17

18 **Securitization**

19 **Q9. Do you agree with the rate used by Staff Witness Rueckert and AG Witness**
20 **Coppola to calculate the Return on Tree Trim Regulatory Asset?**

21 A9. No. The Company maintains its position that any future tree trim surge
22 expenditures should be financed through permanent capital. In past cases (e.g.,
23 Case No. U-21015), the Commission directed DTE Electric to retire existing long-
24 term debt and equity with the proceeds from the sale of the securitization property.
25 The Company feels that it is therefore consistent that the return associated with the

T. J. LEPCZYK

U-21534

Line
No.

1 surge regulatory asset be commensurate with the capital that will ultimately be
2 retired with the proceeds of that securitization.

3

4 **Q10. Do you agree with AG-MN Witness Alvarez's recommendation on Page 41,**
5 **Lines 19 – 20 of his direct testimony, that the Commission reject the**
6 **Company's request to earn a return for shareholders on the Tree Trim Surge**
7 **Regulatory Asset?**

8 A10. No. As stated in Answer 9, the Company maintains its position that its pre-tax
9 weighted average cost of permanent capital should apply to tree trim surge balances
10 prior to securitization, as – in past cases – the Commission has directed the
11 Company to retire long-term debt and equity with the proceeds of securitization.

12

13 **Q11. Does this complete your rebuttal testimony?**

14 A11. Yes, it does

1 JUDGE WALLACE: Please go ahead.

2 MR. JANISZEWSKI: Thank you, your Honor.

3 The Company moves to bind into the record the
4 Qualifications and Revised Direct Testimony of Aaron
5 Willis, consisting of a cover sheet and 46 pages of
6 questions and answers. The Company also moves for the
7 admission of the following 17 direct exhibits that
8 accompanied Mr. Willis's revised direct testimony:
9 Exhibit A-5 Schedule E2, Exhibit A-5 Schedule E3, Exhibit
10 A-13 Schedule C4, Exhibit A-13 Schedule C4.1, Exhibit
11 A-16 Schedule F2, Revised Exhibit A-16 Schedule F3, which
12 is cosponsored by Witness Bellini -- or I'm sorry --
13 Bellini; Exhibit A-16 Schedule F4, Exhibit A-16 Schedule
14 F5, Exhibit A-16 Schedule F6, Exhibit A-16 Schedule F7,
15 Exhibit A-16 Schedule F8, Revised Exhibit A-16 Schedule
16 F9, Exhibit A-17 Schedule G1.1, Exhibit A-17 Schedule
17 G1.2, Exhibit A-17 Schedule G1.3, Exhibit A-17 Schedule
18 G1.4, and Exhibit A-33 Schedule X7. Next, the Company
19 moves to bind into the record the Rebuttal Testimony of
20 Aaron Willis, consisting of a cover sheet and 29 pages of
21 questions and answers. Mr. Willis did not sponsor any
22 rebuttal exhibits, and there are no changes to his
23 testimony and exhibits.

24 JUDGE WALLACE: Thank you,
25 Mr. Janiszewski. Is there any objection to binding in
Penn Reporting, LLC - lori.penn@yahoo.com

1 the revised direct testimony and rebuttal testimony of
2 Mr. Willis?

3 Hearing none, the testimony is bound in.

4 Is there any objection to the admission
5 of the exhibits and associated schedules sponsored by
6 Mr. Willis? (No response.)

7 (Testimony bound in.)

8 - - -

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

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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.

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

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

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

10 A3. I received a Bachelor of 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.

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

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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

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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to 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:

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- 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.

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- 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 Revised 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 Revised	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)

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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.

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- 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.

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- 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

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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

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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)

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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,

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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.

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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.
5

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.
12

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.
18

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

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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).

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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.

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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

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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.

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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.

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- 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

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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

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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

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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.

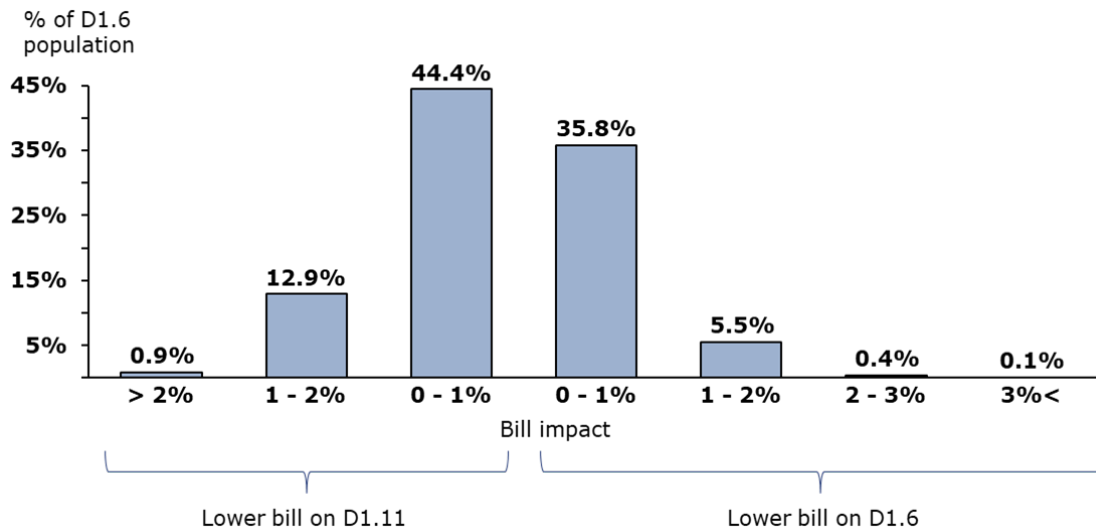
18

⁶ See Exhibit A-14, Schedule F3 Revised

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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

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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?**

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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
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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

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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

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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	1.38x
Non-Summer On Peak	14.82	1.04x
Off Peak	14.25	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.

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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

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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.

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- 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

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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

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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

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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

REBUTTAL TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF AARON WILLIS

Line
No.

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

3 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services,
5 LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my testimony is to respond to Staff and intervenor direct testimony,
14 specifically addressing the topics listed below. The absence of rebuttal on any given
15 matter does not constitute agreement by the Company.

16 1. Respond to Staff Witness Braunschweig regarding the Staff's projection of
17 the Residential Senior Credit

18 2. Respond to Michigan Environmental Council, Natural Resources Defense
19 Council, Sierra Club, and Citizens Utility Board of Michigan (MNSC)
20 Witnesses Jester and Gard's proposal for 1) separate single family and
21 multifamily residential cost of service classes and rate design and 2)
22 separate electric space heating cost of service class and rate design

23 3. Respond to MNSC Witness Jester's proposal for "Resource Adequacy" rate
24 design

Line
No.

- 1 4. Respond to Detroit Area Advocacy Organizations (Souardarity and We
- 2 Want Green, Too (DAAO) Witness Koepfel's recommendation to 1) reject
- 3 the Company's request to retire Rate Schedule D1.6 and provide optionality
- 4 for customers receiving low income assistance credits, and 2) require
- 5 additional studies of time of use rates.
- 6 5. Respond to The Michigan Energy Innovation Business Council, Institute
- 7 For Energy Innovation And Advanced Energy United (MEIU) Witness
- 8 Barnes' recommendations regarding commercial and industrial time of use
- 9 including time periods, enrollment caps, and his proposal for an additional
- 10 D4-based TOU rate.
- 11 6. Respond to Great Lakes Renewable Energy Association (GLREA) Witness
- 12 Rafson regarding proposals to "specifically allow nanogrids and
- 13 microgrids"
- 14 7. Respond to GLREA Witness Richter's proposal to allocate all capacity
- 15 costs to the "peak periods" in the Company's proposed D3.11 and D14
- 16 8. Respond to MEIU Witness Sherman and Electrify America Witness Shah
- 17 regarding proposed extensions to the D3 fast charger carve out

18

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

20 A4. No.

21

22 **Respond to Staff Witness Braunschweig regarding the Staff's projection of the**
 23 **Residential Senior Credit (RSC) Customer Count**

24 **Q5. What does Staff Witness Braunschweig recommend regarding the projection**
 25 **of Residential Senior Credit customer count?**

Line
No.

1 A5. Staff Witness Braunschweig proposes to use a three year trailing average (2020 –
2 2022) to determine the RSC customer count projection of 94,525 customers. This
3 is in contrast to the Company’s proposal of 104,224 customers, which reflects a
4 trendline from the historical years referenced by Staff and included 2023 to date at
5 the time the number was finalized.

6

7 **Q6. How does utilizing full year 2023 actual counts and 2024 actual counts to-date**
8 **support the Company’s position?**

9 A6. 2023 actual credits averaged 109,754 monthly disbursements. 2024 credits to-date
10 are averaging 125,141 monthly disbursements. In addition, Staff Exhibit S-17, pp
11 5-6 includes a Company audit response which describes an error in the Company’s
12 initial filed forecast, which undercounted the forecast by 19,849. Considering these
13 figures alongside the historical information described in the Company’s Part III
14 filing and included in Staff’s testimony, the Company’s initially proposed 104,224
15 is reasonable, and in fact likely an under-forecast. And unlike the Company’s Low
16 Income Assistance Credit, the senior credit is not tracked or reconciled, and a
17 substantial under-forecast is simply unrecoverable in the future.

18

19 **Q7. What do you recommend of the Commission?**

20 A7. I recommend the Commission update the Company’s initial senior credit customer
21 forecast of 104,224 to include the 19,849 credit counts inadvertently excluded from
22 the Company’s initial filing, for a total of 124,073.

23

Line
No.

1 **Respond to MNSC Witnesses Jester and Gard’s proposal to study separate single**
 2 **family and multifamily residential cost of service classes and rate design and**
 3 **separate electric space heating cost of service and rate design**

4

5 **Q8. What do Witnesses Jester and Gard propose regarding residential cost of**
 6 **service and rate design?**

7 A8. Witnesses Jester and Gard broadly describe an analysis they conducted which they
 8 indicate demonstrates that it is appropriate to separate the existing residential cost
 9 of service class into separate classes for single family homes and multifamily
 10 homes. Based on this analysis and additional commentary from Witness Jester,
 11 Witness Gard recommends the Commission require the Company to “conduct a
 12 similar analysis of its residential customers to determine whether continuing to
 13 combine single-family and multi-family customers within a single class is justified¹”.

14

15 Witness Jester further recommends that in addition to requiring the Company to
 16 study separate single family and multifamily cost of service, the Company should
 17 also be required to perform a similar study based on customers with electric space
 18 heating.

19

20 **Q9. What support does Witness Gard offer for his analysis and conclusions that**
 21 **single family and multi family homes should have separate cost of service and**
 22 **rate design?**

23 A9. Witness Gard utilized “realistic building load profiles²” from the National
 24 Renewable Energy Laboratory (NREL) representing “the five Southeastern

¹ MNSC Witness Gard Pg. 5, Ln 9

² Using NREL “ResStock” data

Line
No.

1 Michigan counties of Lapeer, Macomb, Oakland, St. Clair, and Wayne”. Witness
2 Gard then “deconstruct[ed] the 5-county total residential electricity load profile into
3 separate load profiles for single-family and multi-family residential
4 subcategories³”. From this, Witness Gard determined that it is “readily apparent for
5 both critical peak (CP) and noncoincident peak (NCP) COS parameters⁴” that
6 single family and multi family are “unique”.

7

8 **Q10. Does the Company have systematic information for current and future**
9 **customers regarding their heating source or whether the residence is single or**
10 **multi family?**

11 A10. No. As a standard business practice, the Company does not know which residential
12 customers are single v. multifamily (either including or excluding duplexes and
13 mobile homes, as Witness Jester suggests should be classified as single family
14 “since these appear to have similar load profiles⁵”). In addition, unless customers
15 are utilizing a specific rate product or program which requires them to specific
16 appliances they are using (e.g. electric space heating on D2), the Company has no
17 way of knowing which appliances any given customer uses. Said differently, the
18 actual information required to conduct such a study does not exist. Exhibit CUB-
19 24 (Pg 1) acknowledges this, noting “While the Company reports total electricity
20 load profiles for each customer class, these lack sufficient granularity for this
21 analysis. By comparison, the NREL load profiles reflect specific end uses and fuel
22 types, not just total electricity load.” I agree with this assessment, because available

³ MNSC Witness Gard Pg 4, Lns 4-10

⁴ MNSC Witness Gard Pg 5, Lns 1-5

⁵ MNSC Witness Jester Pg 24, Lns 6

Line
No.

1 data of actual DTE Electric customer usage lacks the associated information to
2 perform this analysis, and as such the recommendation should be rejected.

3

4 **Q11. Even if the Company had the available data, is the distinction between single**
5 **family / multifamily and heating source a uniquely important driver of load**
6 **characteristics?**

7 A11. No. To illustrate this, I looked at annual usage as an independent variable to
8 determine if different usage levels indicate different relative 4CP and 12CP
9 behavior (i.e., load behavior and a proxy comparison for Witness Gard's radar
10 plots). Table 1 below shows monthly average annual (using various buckets of
11 usage provided as part of Part III supplemental residential usage distributions) and
12 the associated ratio of 1) average 4CP load to average 12 CP load and 2) average
13 1CP load to average 12CP load. I share this not to make the case that usage should
14 be the basis for different cost of service classes, but rather to underscore that there
15 is no specific significance to single v. multifamily or electric space heating as it
16 concerns which usage drivers ought to be considered for their own cost of service
17 class. As is evident from the table, the peak behavior characteristics are not
18 homogenous across different usage levels (as usage goes up, the apparent load
19 factor improves), but that does not mean it is appropriate to use usage as the basis
20 for different residential cost of service classes or rate schedules. And for
21 completeness, it is not possible for the Company to recreate the table below for
22 space heating and multifamily because these are not categories which are tracked
23 by the Company.

Line
No.

1

Table 1. Peak load characteristics by residential usage levels

Annual Usage Bucket (kWh)	Customer Count	Avg Mo Usage (kWh)	Avg 4CP / Avg 12CP	Avg 1CP / Avg 12CP
23,501 - 24,000	1,388	1,993	133%	142%
17,501 - 18,000	5,785	1,483	137%	147%
11,501 - 12,000	30,532	983	144%	155%
8,501 - 9,000	66,379	733	147%	159%
5,501 - 6,000	110,135	483	149%	162%
4,501 - 5,000	113,130	400	149%	162%
3,501 - 4,000	106,027	317	147%	160%

2

3 **Q12. Do you have any other concerns with the analytic approach used for the**
4 **analysis?**

5 A12. Yes. I have two specific concerns with the analytic methodology used by Witness
6 Gard

- 7 • *The study data was used for purposes other than intended.* The analysis did
8 not seek nor use actual DTE usage data beyond the aggregate residential
9 loads from Supplemental Part III; the breakdown of load curves by housing
10 type is entirely based on the NREL ResStock Tool. As described by NREL,
11 this tool “help[s] states, municipalities, utilities, and manufacturers identify
12 which home improvements save the most energy and money⁶” and was
13 developing using “a statistical model of housing stock characteristics”. The
14 outputs for Michigan on the associated website⁷ are entirely focused on
15 building energy efficiency investments and make no suggestion that this
16 data is precise, specific, or accurate enough to serve as the basis for

⁶ [ResStock Analysis Tool | Buildings | NREL](#)

⁷ [Michigan Residential Energy Efficiency Potential \(nrel.gov\)](#)

Line
No.

1 assertions regarding cost of service and actual customer load shapes. In
2 addition, Exhibit CUB-24 notes “This an appropriate application of the
3 NREL load profiles. Published guidance from NREL explicitly mentions
4 Electrification Planning as one of seven use cases for its end-use load
5 profiles.” Neither this Exhibit nor NREL mention Witness Gard’s use of
6 this data as an intended or appropriate person .

7 • *The analysis ignores other factors that could impact load shapes.* Witness
8 Gard’s analysis and recommendation does not allow for the possibility that
9 characteristics other than single v. multi family or space heating could drive
10 different load curves. The analysis does not question the role of square
11 footage, total usage, compass orientation, tree cover/shading, or presence or
12 lack of central A/C on peak behavior. To the extent the analysis considers
13 space heating load, it appears to be one piece of a broader “building
14 electrification” scenario which is fundamentally an analysis of distribution
15 equipment loading and not metered customer loads. Notably, the analysis
16 also ignores the impacts of electric vehicles and behind the meter
17 generation. Witness Jester indicates that existing tariffs and a desire to “not
18 proliferate additional rate schedules” as reasons not to consider distributed
19 generation⁸. The Company agrees with the overall concept of rate-schedule
20 nonproliferation and suggests it be applied as a general practice.

21

22 **Q13. MNSC Witnesses Jester and Gard each proposed rates specifically for electric**
23 **space heating. Does the Company offer this rate already?**

⁸ MNSC Witness Jester Pg 27, Ln 1-7

Line
No.

1 A13. Witness Gard and Witness Jester each propose new cost of service classes and rate
2 schedules for electric heating customers. In addition to the simple lack of data on
3 heating sources, it is important to highlight that the Company currently serves a
4 portion of customers on Rate Schedule D2, which is an entirely voluntary⁹ base
5 service for customers with electric space heating. This rate is served on its own cost
6 of service class as described by Witness Maroun and myself. However, the
7 Commission chose to close new enrollments on this rate in 2015. Thus, to the extent
8 Witnesses Jester and Gard seek an optional electric space heating rate, the
9 Commission has previously closed that product, and to the extent Witnesses Gard
10 and Jester are suggesting a mandatory rate, the Company again does not know who
11 has electric heating and who does not and it would be an inappropriate approach
12 even if the Company had the data.

13

14 **Q14. What do you recommend to the Commission regarding the proposals for**
15 **separate space heating and multifamily cost of service studies?**

16 A14. I recommend the Commission reject the proposals outlined by MNSC Witnesses
17 Gard and Jester, including:

- 18 • Proposal for a single family v. multifamily cost of service study on the basis
19 that 1) the data is unavailable and 2) the proposal has not demonstrated that
20 the distinction between single and multifamily usage is the most significant
21 and uniquely warrants a new cost of service study
- 22 • Proposal for electric space heating v. no electric space heating cost of
23 service study on the basis that 1) the data is unavailable, and 2) the Company

⁹ An important distinction as the Company can only conduct the COSS and offer D2 because the electric heating customers have self-identified over time

Line
No.

1 continues to offer such a rate on a grandfathered basis, with the rate having
2 been previously closed by the Commission.

3

4 **Respond to MNSC Witnesses Jester's proposal to introduce alternative capacity**
5 **charges related to his proposed changes to how production plant is allocated**

6 **Q15. Please describe Witness Jester's proposal.**

7 A15. Witness Jester proposes two alternative approaches for how production plant costs
8 are allocated, based on his interpretation of when and how capacity resources are
9 utilized. These proposals are addressed in the rebuttal testimony of Company
10 Witness Maroun, however I will address Witness Jester's further proposal to
11 modify rate design based on the aforementioned proposals. Witness Jester says
12 "Consistent with the principle that rate design should reflect cost causation as
13 allocated in the cost-of-service model, the method by which seasonal Resource
14 Adequacy is incorporated into rate design should depend on the Production Plant
15 method applied to determine cost of service.¹⁰" He additionally recommends "an
16 analysis of the seasonality for cost causation of distribution costs and distribution
17 rate designs consistent with that seasonality" – this proposal is addressed by
18 Company Witnesses Maroun and Deol in their respective rebuttal testimonies.

19

20 **Q16. What issues do you observe with this proposal?**

21 A16. I see several issues with this proposal.

- 22 • Rate design and COS are not the same. If they were the Company would:
 - 23 ○ 1) collect 75% of production plant costs (75-0-25) as a demand charge
 - 24 ○ 2) apply the demand charge only in the 4CP summer months.

¹⁰ MNSC Witness Jester Pg 20, Ln 3

Line
No.

1 The Company does not create rates in this manner. A recommendation that rates
2 should be designed based on this or either of Witness Jester's cost of service
3 proposals would break significantly with ratemaking precedent in Michigan and
4 would be a significant change to customers who would now be presented with
5 seasonal demand rates.

6 • My interpretation of Witness Jester's proposal is that he is recommending
7 structural changes to every rate schedule the Company offers and which
8 includes capacity charges based on his recommendations to change cost of
9 service production plant allocations¹¹. For demand schedules, it appears the
10 proposal is to change to a seasonal demand charge model, which would be a
11 change for all relevant rates. For time of use rate schedules, it appears to suggest
12 modifying the time periods, the seasons, and the underlying cost allocations to
13 the rates. Said differently, the proposal would appear to require changes to more
14 than a dozen rate schedules impacting more than two million customers. The
15 Company does not support such a significant change and this recommendation
16 should be rejected.

17

18 **Respond to DAAO Witness Koeppel's recommendation to 1) reject the Company's**
19 **request to retire Rate Schedule D1.6 and provide optionality for customers receiving**
20 **low income assistance credits, and 2) require additional studies of time of use rates.**

21

22 **Q17. Please describe DAAO Witness Koeppel's discussion and recommendations**
23 **related to the Company's proposals to transition D1.6 customers and make the**
24 **low income assistance (LIA) available on all base rates?**

¹¹ Which are addressed separately by Company Witness Maroun

Line
No.

1 A17. As Witness Koeppel describes, in Case No. U-21297 the Company proposed to 1)
2 transition D1.6 customers to D1.11 (or any other base rate of their choosing), 2)
3 make the LIA credit available on any residential base rate, and 3) close D1.6 as the
4 Company and State has transitioned to TOU residential rate design. The
5 Commission then ordered the Company to conduct an impact study of such a
6 transition¹². Broadly, Witness Koeppel's essential observation is that "DTE cannot
7 establish that the switch would not significantly harm its LMI customers...¹³" and
8 as such "...the Commission still does not have the necessary data to approve the
9 retirement of the D1.6 rate¹⁴".

10

11 **Q18. How does Witness Koeppel characterize the analysis conducted by the**
12 **Company?**

13 A18. Witness Koeppel suggests that the study is based on a comparison of customers
14 who have actually switched from D1.6 to D1.11 (see, for example, "DTE's analysis
15 does not provide any information on the rate of shut-offs for customers that
16 switched from the D1.6 rate to the D1.11 rate¹⁵"). For clarification, the Company's
17 study only looks at customers on D1.6 in 2022, and with their actual usage on D1.6,
18 compares their actual D1.6 bill to a hypothetical D1.11 bill in the alternative. The
19 data to perform a comparison of actual behavior on each rate using statistically
20 valid matched pairs is simply unavailable and would be extremely resource
21 intensive to design and produce.

22

¹² December 1, 2023, Order in Case No. U-21297, Pg 372

¹³ DAAO Witness Koeppel Pg 38 Ln 4

¹⁴ DAAO Witness Koeppel Pg 38 Ln 15

¹⁵ DAAO Witness Koeppel Pg 38 Ln 1

Line
No.

1 **Q19. Does Witness Koeppel have any specific concerns with the analysis presented**
2 **by the Company?**

3 A19. Witness Koeppel advocates for several additional elements as part of the Bill
4 Impact Study and argues that the overall study is insufficient, but he does not appear
5 to dispute or take issue with the basic conclusions the Company's study did reach
6 based on what was included. As illustrated in my revised direct testimony at Pg 24,
7 the central, undisputed conclusion is that nearly 60% of D1.6 customers would have
8 been better off on D1.11 in 2022. Witness Koeppel acknowledges the central
9 observation of the Company's direct testimony on the topic that there is no
10 structurally adverse impact to D1.6 customers transitioning to D1.11 and in fact, on
11 average, these customers would have seen a 0.17% reduction in their bill had they
12 been on D1.11 in 2022¹⁶. No issues are highlighted regarding the underlying data,
13 the method used by the Company to compare the bills, or the basic quantitative
14 outputs. Said differently, Witness Koeppel is focused on what was not included but
15 does not contest what was included.

16

17 One additional element Witness Koeppel recommends is a "regression analysis to
18 identify any statistically significant difference in the impacts of TOU rates on
19 different customers". The analysis in the Company's direct testimony utilized
20 approximately 26,000 customers bills, both actual and calculated, to arrive at the
21 conclusion that there is no structurally adverse impact to D1.6 customers.
22 Moreover, the Company's Advanced Customer Pricing Pilot and its associated
23 analysis of different customer groups (which among the broad population of
24 residential customers includes low income customers, seniors, etc) was sufficient

¹⁶ DAAO Witness Koeppel Pg 37 Lns 14-17

Line
No.

1 for the Commission to approve default TOU rates for approximately two million
2 customers (including low income, seniors, etc).
3

4 Given the approximately 26,000 customer loads used for the Company's study
5 (which was every customer on D1.6 in 2022 with more than 300 days of usage
6 data), it is not evident what more is required to establish that "the switch would not
7 significantly harm" current customers on D1.6. Moreover, Witness Koeppel
8 continues to suggest an analysis with a scope well beyond what the Commission
9 felt necessary to require before moving two million customers to TOU (many of
10 whom fit the customer categories Witness Koeppel is focused on¹⁷).
11

12 **Q20. Which rates can LIA customers choose to take service on today?**

13 A20. Today, LIA customers have no choice in their rate schedule and they are required
14 to take service on D1.6, even if they prefer D1.11, D1.2, or D1.8. The current
15 arrangement provides no optionality, which all other residential customers have,
16 and requires customers to change rates to receive the credit. Moreover, it is
17 administratively unnecessary for both the Company and customers.
18

19 **Q21. Is there precedent for the Commission to close rates utilized by specific
20 customer groups and instead offer a credit available on any rate schedule?**

21 A21. Yes. In Case No. U-17767, the Commission approved closing the Company's prior
22 Rate Schedule D1.3, which was available to senior customers as a mechanism to
23 provide a bill discount. In the alternative, the Commission approved a senior credit
24 which is now available on all residential base rates. This is fundamentally

¹⁷ E.g., family size, having a disability, having children and elders, having all working parents as described by DAAO Witness Koeppel Pg 35, Ln 14.

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1 analogous to the entirety of the Company's request in this case regarding D1.6, one
2 that is supported by a robust record in this and prior cases.

3

4 **Q22. What action do you recommend of the Commission regarding the Company's**
5 **D1.6 proposals?**

6 A22. I recommend the Commission approve three things:

- 7 • The transition of all D1.6 customers to D1.11 as proposed by the Company.
8 This will conclude the Company's overall transition of residential
9 customers to TOU rates.
- 10 • Close Rate Schedule D1.6 at such time all customers are transitioned.
- 11 • Make the LIA credit available on any residential base rate for which the
12 customer otherwise qualifies. In doing so, customers will have the
13 flexibility and freedom to take service on the rate of their choosing while
14 also removing the complication of forcing customers to change rates when
15 they begin and when they no longer receive the credit.

16

17 **Respond to MEIU Witness Barnes' recommendations regarding commercial and**
18 **industrial time of use including time periods, enrollment caps, and his proposal for**
19 **an additional D4-based TOU rate.**

20

21 **Q23. What does MEIU Witness Barnes recommend regarding the Company's**
22 **commercial and industrial time of use rate proposals?**

23 A23. Witness Barnes makes five separate recommendations. Here I address and discuss
24 the first three, while the recommendations related to implementation timing and

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1 rate comparison reports are addressed in the rebuttal testimony of Company
2 Witnesses Hatsios and Sharma. In summary, Witness Barnes recommends:

- 3 • There should be a third commercial/industrial TOU rate which is a
4 “corollary for Rate Schedule D4”.
- 5 • The rates should have a common on-peak pricing period utilizing 1:00 –
6 5:00 weekdays, which would change the proposed on-peak period for D14
- 7 • The proposed enrollment caps should be rejected.

8 I will address each of Witness Barnes’ recommendations below.

9
10 **Q24. Why does Witness Barnes believe it is appropriate to introduce a third C&I**
11 **rate associated with Rate Schedule D4?**

12 A24. Witness Barnes begins by describing the customers who, all else equal, relatively
13 benefit on D3 and D4 – higher load factor customers benefit relatively from demand
14 rates and lower load factor customers benefit relatively from volumetric rates¹⁸.
15 Witness Barnes then observes that, because D3 and D4 have “different usage
16 determinants, different revenue requirements, and different average volumetric
17 rates”, they have different average power supply volumetric costs. Because the
18 proposed secondary voltage TOU rate is revenue neutral to D3, but not the
19 relatively less expensive D4, Witness Barnes concludes that D4 customers would
20 be without sufficient choice of rate schedules unless the Company also offers a
21 TOU rate which is revenue neutral to D4. Witness Barnes’ central argument is that
22 D3 and D4 should have linked TOU rate schedules because the average power
23 supply rate on those rates is not the same.

24

¹⁸ MEIU Witness Barnes Pg 9 Ln 4

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1 **Q25. Do you agree with Witness Barnes' approach to TOU rate design?**

2 A25. No. The average effective rate on any rate schedule is driven primarily by the
3 efficiency of the usage on the rate. All else equal, a cost-of-service class with a
4 higher load factor will have a lower average rate than one with a lower load factor.
5 D3 and D4 are in different cost of service classes, and D4 has a higher average load
6 factor and thus lower average rates. D4 rate design, which utilizes demand charges,
7 reinforces this self-selection for higher load factor customers. If the Company
8 offered a TOU rate using a D4 revenue neutral design, the "lower rate" would be a
9 fleeting reality.

10

11 Two groups of customers would presumably seek to enroll on a D4-neutral TOU
12 rate in the near term. The first group would be D4 customers with a load factor high
13 enough to justify being a D4 customer but one that is lower than the D4 average.
14 This group would switch rates to maintain the benefits of the lower average power
15 supply rate while simultaneously avoiding the power supply demand charge design
16 that drives the more efficient usage (and which in turn drives the lower average
17 rate). All else equal, this would have the natural effect of *increasing* the average
18 power supply rate on Witness Barnes' proposed D4.1 to something between the
19 current D3 and D4 average power supply rates¹⁹. Such a change would require a
20 new cost of service class for D4.1 in the future so as not to adversely impact the D4
21 cost of service class. The second group would be those current D3 customers with
22 the highest load factors, but which are not high enough to benefit from D4 today.
23 In the future, they could benefit from the lower power supply cost of a D4-neutral
24 rate more than the distribution demand charges harms them (if at all). This would

¹⁹ As a corollary, the D4 average power supply rate would decrease as it sheds lower load factor customers

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1 also have the natural effect of *increasing* the average D4.1 power supply rate.
2 Described differently, average rates, regardless of the rate design, simply reflect the
3 characteristics of the customers on the rates. Over time, Rate Schedule D4.1 would
4 simply reflect the poorer load factor relative to D4 and (presumably) better load
5 factor relative to D3 or D3.11.

6

7 To the extent an existing D4 customer could benefit by switching to the Company's
8 proposed D3.11, they would be able to do so. Moreover, if the customer exceeds
9 50 kW of demand, they may also be able to leverage the Company's proposed
10 primary TOU rate D14, which has an even lower average power supply rate (by
11 13% compared to D4 and based on the better D11 load factor) and a lower
12 distribution demand charge. Far from a "poison pill" for existing D4 customers²⁰,
13 the Company's TOU proposal is conceptually sound and offers options for all C&I
14 customers.

15

16 **Q26. What was the Company's rationale for designing the proposed secondary**
17 **voltage TOU rate revenue neutral to D3 and not D4?**

18 A26. In its Order in Case No. U-21297, the Commission included a reference to "mass
19 market appropriate TOU rate options" in the introduction to the discussion.
20 Considering customer counts on D3 and D4, D3 is clearly the "mass market" analog
21 upon which to develop a time of use rate. Whereas D3 has approximately 200,000
22 customers, D4 has fewer than 10,000 customers.

23

²⁰ MEIU Witness Barnes Pg 10 Ln 7

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1 **Q27. Witness Barnes proposes that the Company's proposed D14 utilize the same**
2 **1:00 – 5:00 on-peak period as proposed D3.11. Do you agree?**

3 A27. No. The Company designed the D14 on-peak period to maintain consistency with
4 the existing D11 on-peak period²¹. The D3.11 on-peak period is proposed to
5 broadly align with 1) summer system coincident peaks and 2) summer class peaks.
6 The inclusion of system peaks aligns pricing periods with system highest use
7 periods, and the inclusion of summer class peaks limits the possibility that the on-
8 peak period could drive snapback and inadvertently set a new class peak hour on
9 the edge of the on-peak period. Utilizing the Company's Supplemental Part III
10 filing, Att 5 (29), 20% of the primary summer peaks from 2018-2022 are before
11 1:00 pm. An on-peak window beginning at 1:00 pm certainly presents the
12 possibility of customer's shifting load to before the period and in doing so
13 inadvertently create a new system peak hour in the noon – 1:00 pm hour.

14

15 In addition, Witness Barnes' indicative D14 rates under a 1:00 – 5:00 scenario
16 appear to assume no change in load behavior, which for voluntary time of use rates
17 with new pricing windows is highly unlikely. The Company's proposed D14
18 included no shift because it mimics the existing TOU pricing window on D11 and
19 therefore is already embedded in existing rate design.

20

21 **Q28. What does Witness Barnes recommend regarding the Company's proposed**
22 **enrollment caps on D3.11 and D14?**

23 A28. Witness Barnes is broadly opposed to enrollment caps, noting "The introduction of
24 such rates should not be accompanied by new constraints on their availability. At

²¹ Further discussed in the revised direct testimony of Company Witness Willis, Pg 41 Ln 20

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1 best, such limits introduce administrative inefficiency since their removal would
2 require further litigation in future rate cases. At worst, they may further delay the
3 availability of TOU rates to all customers that wish to participate.²²”

4
5 He further describes his view of new rate introductions and their attendant cost-
6 recovery risk, saying “any supposed risk of under-recovery rests on speculation
7 rather than evidence, and such risk is not necessarily greater or lower than the risk
8 of under-recovery present within the broader groups of customers²³”. Continuing
9 on this topic, Witness Barnes says “the prospect of lower revenue is not by itself
10 indicative of under-recovery of costs or unreasonable cost-shifting to other
11 ratepayers²⁴”

12
13 Lastly, Witness Barnes indicates concern that caps proposed by the Company are
14 not time-bound but are instead dynamic to enrollments and actual customer usage
15 information.

16
17 In summary, Witness Barnes believes 1) caps are generally unreasonable will
18 prevent customer enrollment on the rates, and 2) that to the extent usage behavior
19 is different than the Company’s forecast, any resultant under-recovery is
20 appropriate.

21

22 **Q29. How do you respond to the proposed elimination of the enrollment caps?**

23 A29. They should be retained. Specifically:

²² MEIU Witness Barnes Pg 16, Ln 10

²³ MEIU Witness Barnes Pg 16 Ln 18

²⁴ MEIU Witness Barnes Pg 17, Ln 4

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- 1 • *The evidence does not support the claim that caps will prevent enrollment.* In
2 his continuing discussion of enrollment caps, Witness Barnes introduces for
3 reference the experience of Consumers Energy’s (CE) implementation and
4 initial enrollment caps. As described, CE initially sought approval of their
5 commercial secondary and primary rates in 2017, seven years ago. In that time,
6 according to Witness Barnes, CE has seen enrollments representing ~0.84% of
7 commercial secondary customers²⁵. The Company’s proposed cap for initial
8 D3.11 enrollment is equivalent to 0.5% of commercial secondary customers²⁶.
9 Given the seven years it apparently took for 0.84% of CE’s commercial
10 secondary customers to enroll on their TOU rate, it does not seem likely that
11 there will be any near-term concerns related to enrollment limitations on D3.11.
12
13 Regarding D14, Witness Barnes again notes the CE experience, which provides
14 a nearly analogous situation for the Commission to consider. He highlights that
15 CE initially proposed, and the Commission approved, enrollment caps on their
16 then new primary TOU rate. The reason provided by CE, and which Witness
17 Barnes highlights, is “At the time of this expansion, ***Schedule GPTU had not***
18 ***been in place long enough for it to be evaluated as a separate rate schedule***
19 ***in Consumers Energy’s cost of service study*** so rates continued to be based on
20 a revenue-neutral mapping to the broader primary voltage rate schedule²⁷,
21 *(emphasis added)*. This is nearly verbatim to my direct testimony on the topic,
22 which says, “Until such time that D14 is supported by its own cost of service
23 class... the Company proposes to limit total load on this rate to 50 MW of

²⁵ MEIU Witness Barnes Pg 19 Ln 9

²⁶ Willis Revised Direct, Pg 32 Ln 4

²⁷ MEIU Witness Barnes Pg 18, Ln 7

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1 contract capacity²⁸”. Also of relevance, today CE does utilize a separate COS
2 class for GPTU, presumably because it has the historical data to do so.

3

4 • *Short term caps prevent adverse outcomes.* The Company’s rates are based on
5 the best available forecast of 1) what customer usage, by rate schedule, will be
6 in the projected test year, and 2) the Company’s revenue requirement in the
7 projected test year. The Company’s best available forecast of customer usage
8 on the proposed D3.11 and D14 includes more uncertainty than a long-existing
9 rate because they each introduce fundamentally different pricing signals to
10 customers. The Company’s existing rates have strong historical, empirical data
11 to support forecasts – new rates with fundamentally different pricing structures
12 do not. One outcome of this, particularly for larger and more sophisticated
13 primary customers, could be drastically different load profiles than what was
14 anticipated based on historical information (and ultimately incorrect cost
15 allocation assumptions).

16

17 Additionally, the Company is concerned with Witness Barnes’ assertion that
18 “the prospect of lower revenue is not by itself indicative of under-recovery of
19 costs or unreasonable cost-shifting to other ratepayers”. While the Company
20 appreciates that actual revenue is unlikely to be exactly the ordered revenue
21 requirement, it is inappropriate to introduce potential structural drivers of
22 under-recovery. While D14 is allocated costs based on the load factor and
23 efficiency of D11, it will almost certainly have a lower realized load factor due
24 to the fact that the rate is more attractive to lower load factor customers. In the

²⁸ Willis revised direct Pg 43 Ln 14

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1 short run, their effective rates would be artificially low. It is therefore
2 appropriate to implement a cap until such time the rate is supported by its own
3 cost of service class.

4

5 **Q30. In summary, what do you recommend the Commission order regarding the**
6 **Company's C&I TOU proposals and MEIU's recommendations?**

7 A30. I recommend the Commission approve the rates as filed, including time periods and
8 caps, and recommend the Commission decline to adopt MEIU's proposal for a third
9 TOU rate based on D4.

10

11 **Response to GLREA Witness Rafson regarding proposals to "specifically allow**
12 **nanogrids and microgrids"**

13

14 **Q31. What is GLREA's recommendation regarding microgrids and "nanogrids"?**

15 A31. Witness Rafson describes several apparent benefits of microgrids and nanogrids
16 and then recommends the Commission "should specifically allow nanogrids and
17 microgrids" and "This regulatory step is particularly justified as a response to
18 DTE's failure to serve essential power to their customers²⁹".

19

20 **Q32. As described by Witness Rafson, do the Company's tariffs allow "nanogrids"**
21 **today?**

22 A32. Yes. Witness Rafson describes the benefits of nanogrids as "... (behind the meter)
23 installations of any combination of backup generators, solar and energy storage
24 facilities, EV charging (including bi-directional EV charging) technology, and

²⁹ GLREA Witness Rafson Pg 13 Ln 11 and 20

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1 other demand response controls allow customers to provide for themselves reliable,
2 potentially renewable, energy and can help to ensure that they have the essential
3 power they need³⁰. All of the technologies described by Witness Rafson are
4 available to customers under current Company tariffs and require no changes to the
5 Company's tariffs.

6

7 **Q33. Are there regulatory and legal concerns with Witness Rafson's "microgrid"**
8 **proposal?**

9 A33. Yes. The relevant testimony suggests that microgrids include service between
10 multiple individual customers, islanded groups of individual customers, and
11 "submeters" across neighborhoods³¹. The previous description suggests that it
12 would be appropriate and legal for groups of individual customers to create single
13 service points, behind which they act as their own electric utility service. While this
14 may be appropriate for single customer campuses or large commercial sites with
15 single service points, what Witness Rafson describes would require fundamental
16 change to utility regulation in Michigan and the concept of who is a utility. This
17 should be rejected.

18

19 **Respond to GLREA Witness Richter's proposal to allocate all capacity costs to the**
20 **"peak periods" in the Company's proposed D3.11 and D14**

21 **Q34. Please describe Witness Richter's capacity cost recovery proposal?**

22 A34. Witness Richter says "The charge for capacity reflects the cost of ensuring there is
23 sufficient generation and transmission available to meet that peak load. Therefore,
24 it would be accurate to assign the entire cost of capacity to the peak demand time

³⁰ GLREA Witness Rafson Pg 13 Ln 15

³¹ GLREA Witness Rafson Pg 13 Ln 6

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1 period³².” He then goes on describe why these rates are appropriately modified as
2 he recommends, saying “the proposed C3.11 and D14 commercial TOU rates are
3 purely optional, at the discretion of the customer³³”, comparing this optional design
4 to similar capacity cost proposal which the Commission rejected.

5 Ultimately, he recommends:

- 6 • Redesign D3.11 and D14 to include his proposed ‘on-peak only’ capacity
7 recovery approach to be filed 60 days following the conclusion of the instant
8 case, a recommendation which is buttressed with extracts from James
9 Bonbright which say “The generation, transmission, and distribution systems
10 have been built to serve peak demand. During off-peak periods much of this
11 capacity is idle...” and “[e]conomic efficiency simply dictates that consumers
12 should be faced with prices reflecting the true costs they impose on society
13 regardless of how they choose to react to these tariffs³⁴”.
- 14 • The Commission order the Company to include in its next case “a discussion of
15 the pros and cons of making a TOU rate structure the default, standard rate
16 structure for all secondary voltage commercial customers, and to collect metrics
17 of success on the pilots to prepare for making them the default standard rate³⁵”

18

19 **Q35. What observations do you have with respect to Witness Richter’s**
20 **recommendations?**

21 A35. Witness Richter’s central arguments are 1) economic efficiency is the only
22 important consideration in rate design, and 2) this proposal is supportable because
23 it is a voluntary and not mandatory rate.

³² GLREA Witness Richter Pg 13 Ln 3

³³ GLREA Witness Richter Pg 14 Pn 11

³⁴GLREA Witness Richter Pg 13 Ln 17 and 22

³⁵ GLREA Witness Richter Pg 16 Ln 12

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- 1 • *Economic efficiency.* As a conceptual point, the Company does not agree
2 that its capacity only exists to serve the 4CP (or the on-peak periods more
3 generally). The Company has load at all hours of the day and must have
4 capacity to serve that load. In addition, the natural conclusion of Witness
5 Richter’s citation of Bonbright focused on rates reflecting “true costs” and
6 idle capacity in the off-peak would be to have demand rates for all
7 customers³⁶, since capacity is reflected as a demand measure and Witness
8 Richter emphasizes the Bonbright conclusion that “only the operating costs
9 need to be considered³⁷” in the off peak. This is an unreasonable
10 recommendation.
- 11 In addition, this recommendation would suggest all capacity costs be
12 recovered in only the 4CP on-peak periods to maintain consistency with the
13 basic approach of production plant allocation. However, that would 1)
14 create extraordinarily high summer on-peak rates³⁸ and 2), as I remarked in
15 response to Witness Jester above, cost of service and rate design are not the
16 same and have different considerations. While the economic efficiency of
17 rate design is certainly one consideration (and one the Commission has
18 evidenced support of via recent developments of TOU rates), it is not the
19 only consideration.
- 20 • *Mandatory v voluntary v pilot.* That these proposals are for voluntary,
21 optional rates does not mean that the rate should be inappropriately
22 designed. Witness Richter frames D3.11 and D14 as “pilots” and on this

³⁶ Which, to be clear, the Company is not proposing.

³⁷ GLREA Witness Richter Pg 13 ln 25

³⁸ Elsewhere in testimony (Pg 36, Ln 11), Witness Richter refers to the dynamic peak pricing rate schedule D1.8 as having a “punishingly high” rate during CP-events. While the Company has not calculated the impacts of Richter’s proposal, it would invariably lead to much higher on peak or summer on-peak rates compared to the status quo, which could similarly be described as “punishing”

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1 basis concludes that “bold” and “radical³⁹” rate design is appropriate. I
2 disagree. For one, these are not pilot rates and are intended to be enduring,
3 reasonable designs for commercial and industrial TOU rates. That they are
4 voluntary (pilot or otherwise) does not lead to the conclusion that the
5 Commission should support radical rates. Second, Witness Richter
6 seemingly acknowledges this long-term view because he proposes a future
7 discussion of making these TOU rates default for the relevant customers
8 and in addition “to collect metrics of success on the pilots to prepare for
9 making them the default standard rate”. These rates cannot both be a pilot
10 suitable for non-standard rate design while also a prospective default rate.

11

12 **Q36. What do you recommend to the Commission regarding Witness Richter’s**
13 **TOU proposals?**

14 A36. The Commission should reject Witness Richter’s recommendations because:

- 15 • Capacity serves load in all hours
- 16 • Economic efficiency is but one of many considerations in rate design and
17 in this case would drive substantial impacts to customers
- 18 • These are, and should remain, optional (non-pilot) rates. It would be
19 exceptionally premature to begin any discussion of *requiring* these rates
20 when the Commission has yet to approve their basic structure and there are
21 currently no customers enrolled on them.

22

23 **Respond to MEIU Witness Sherman and Electrify America Witness Shah regarding**
24 **proposed extensions to the D3 >1000 kW fast charger exemption**

³⁹ GLREA Witness Richter Pg 14 Ln 13

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1 **Q37. Please describe the recommendations of Witnesses Sherman and Shah?**

2 A37. MEIU Witness Sherman says that in order to “provide sufficient time for DCFC
3 usage to approach a market equilibrium” and to “ensure that demand-based rates
4 do not inhibit the expansion of DCFC for sites with high demand but low utilization
5 rates in the interim”, the Commission should extend the D3 >1000kW fast charger
6 exemption for four years, until January 1, 2030⁴⁰⁴¹.

7

8 Similarly, Electrify America Witness Shah says “Given the timelines associated
9 with DCFC site development and investment justification, which are often over a
10 10-year or longer period, two years of guaranteed demand charge relief is not a long
11 enough period to provide enough cost certainty to Electrify America when it is
12 making investment decisions in DTE’s service territory. DTE should therefore
13 modify its tariff language to allow DCFC sites built before a specified date,
14 preferably by 2028 or later, to be able to take service under the D3 rate⁴²”.

15

16 **Q38. Does the Company agree with these proposals?**

17 A38. No. The Commission previously extended the exemption period in the Company’s
18 last general rate case⁴³ to the current date of June 1, 2026 (extended from June 1,
19 2024). Neither Witness Sherman nor Shah provides any particular evidence of the
20 necessity of their proposed changes. The Company’s D3 tariff, with or without the
21 1000 kW exemption, will continue to serve fast chargers less than 1000 kW

⁴⁰ The Company notes for completeness that the current D3 tariff (rate book sheet D-18.00) indicates a June 1, 2026 date, not a January 1, 2026 date.

⁴¹ MEIU Witness Sherman Pp 52-53

⁴² EA Witness Shah Pp 4-5

⁴³ Dec 1 Order in Case No. U-21297 Pg 341

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1 indefinitely and there is no evidence that the tariff is inhibiting the deployment of
2 fast chargers.

3

4 Witness Shah suggests that the current two year exemption is not sufficient because
5 investment justifications for such assets are made over “a ten year period or
6 longer⁴⁴”. All of the Company’s rates are subject to periodic change, and all of the
7 Company’s customers must make investment decisions based on the best
8 information at hand. No other customer is granted a ten year period of certainty
9 over their rate options and it would be inappropriate to do so here, particularly as
10 the outcome of the recommendation would continue to defer the requirement that
11 customers with very large (>1000 kW) demands be served on a demand-based rate.
12 Moreover, the Company has proposed a primary voltage time of use rate in this
13 case which does not include power supply demand charges, which if approved
14 provides yet another option for charging customers.

15

16 As such, I recommend the Commission reject the proposals to further modify the
17 >1000 kW fast charger exemption on D3.

18

19 **Q39. Does this conclude your rebuttal testimony?**

20 A39. Yes, it does.

21

(Due to court reporter numbering error, there are no page numbers
2646 through 2654.)

⁴⁴ EA Witness Shah Pp 4-5

1 JUDGE WALLACE: O.K. Please go ahead,
2 Mr. Janiszewski.

3 MR. JANISZEWSKI: That concludes the
4 witnesses that I'm responsible for, however, I have one
5 more clarification. I already tried to clarify this once
6 and I did it incorrectly, I apologize. This relates to
7 the one rebuttal exhibit sponsored by Mr. Hatsios. The
8 correct labeling of that exhibit is Exhibit A-44 Schedule
9 LL1.

10 JUDGE WALLACE: All right. Thank you for
11 that clarification. Got it.

12 MR. JANISZEWSKI: And now I will turn to
13 my colleague, Ms. Breanne Reitzel.

14 MS. REITZEL: Good morning, your Honor.

15 JUDGE WALLACE: Good morning.

16 MS. REITZEL: I will start with Keegan O.
17 Farrell, and DTE would move to bind into the record the
18 Direct Testimony of Keegan Farrell, consisting of a cover
19 sheet and 51 pages of questions and answers, as well as
20 for the admission of six direct exhibits and schedules
21 designated as Exhibit A-12 Schedule B5.6, Exhibit A-12
22 Schedule B.6.1, Exhibit A-12 Schedule B5.6.2, Exhibit A-5
23 (sic) Schedule B5.6.3, Exhibit A-12 Schedule B5.6.4, and
24 Exhibit A-13 Schedule C5.9. Mr. Farrell also had
25 rebuttal testimony, consisting of a cover sheet and 13

1 pages of questions and answers, with no rebuttal
2 exhibits.

3 JUDGE WALLACE: Thank you. Is there any
4 objection to binding in the direct and rebuttal testimony
5 of Mr. Farrell?

6 Hearing none, the testimony is bound in.

7 Is there any objection to the exhibits
8 and/or associated schedules sponsored by Mr. Farrell?

9 (No response.)

10 (Testimony bound in.)

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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
DIRECT TESTIMONY
OF
KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEEGAN O. FARRELL

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

2 A1. My name is Keegan O. Farrell (he/him/his). My business address is: One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE
4 Electric or Company) as the Manager of Demand Response.

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 Michigan State University with a Bachelor of Arts Degree in
11 Communication. In addition, I received a Master of Science Degree in Decision
12 Technologies from the University of North Texas.

13

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

15 A4. From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth,
16 Texas where I held positions of increasing responsibility, ultimately serving as a
17 Decision Support Analyst. In this role, I was responsible for assisting with
18 calculating reservoir economics, monitoring daily oil and natural gas production,
19 and overseeing the compliance and emission calculations for the Environmental
20 Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I
21 joined DTE Energy as a Senior Business Financial Analyst – Load Research. In
22 2014, I was promoted to Principal Financial Analyst – Load Research. In this
23 position, I was responsible for developing and implementing statistical sampling
24 programs used to evaluate customer class usage characteristics, developing

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1 allocation schedules for use in cost-of-service studies and rate design, and for
2 measuring and evaluating demand response programs offered by the Company. In
3 2018, I accepted the position of Supervisor Program Management – Demand
4 Response (DR).

5

6 **Q5. What is your current position?**

7 A5. In 2021 I was promoted to Manager of DR. In this position I am responsible for
8 overseeing DTE Electric's DR portfolio, which includes short- and long-term
9 strategic development, marketing and management of DR programs and pilots.

10

11 **Q6. Do you hold any certifications or are you a member of any professional**
12 **organizations?**

13 A6. Yes. I am the course coordinator for the Association of Edison Illuminating
14 Companies (AEIC) Fundamentals for Load Data Analysis course. In addition, I
15 represent DTE Energy on the board of the Peak Load Management Alliance
16 (PLMA).

17

18 **Q7. Have you received industry related training?**

19 A7. Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I
20 have also attended various courses at Michigan State University Institute of Public
21 Utilities Annual Regulatory Studies Program as well as the Demand Response
22 Fundamentals and Evolution Course presented by the PLMA.

23

24 **Q8. Have you previously sponsored testimony before the Michigan Public Service**
25 **Commission (MPSC or Commission)?**

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- 1 A8. Yes. I have sponsored testimony and exhibits before the MPSC in the following
- 2 DTE Electric cases:
- 3 Case No. Description
- 4 U-18014 DTE Electric 2016 General Rate Case
- 5 U-18255 DTE Electric 2017 General Rate Case
- 6 U-20162 DTE Electric 2018 General Rate Case
- 7 U-20471 DTE Electric 2019 Integrated Resource Plan (IRP)
- 8 U-20521 DTE Electric 2017-2018 Demand Response Reconciliation Case
- 9 U-20793 DTE Electric 2019 Demand Response Reconciliation Case
- 10 U-21044 DTE Electric 2020 Demand Response Reconciliation Case
- 11 U-20836 DTE Electric 2022 General Rate Case
- 12 U-21242 DTE Electric 2021 Demand Response Reconciliation
- 13 U-21193 DTE Electric 2022 IRP
- 14 U-21297 DTE Electric 2023 General Rate Case

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1 **Purpose of Testimony**

2 **Q9. What is the purpose of your testimony?**

3 A9. The purpose of my direct testimony is to discuss the demand response efforts that
4 DTE Electric is conducting and provide support for the expenditures and activities
5 associated with the continuation of programs and pilots, as well as briefly discuss
6 the evolving DR landscape. I also discuss the development, future plans, and related
7 expenditures associated with the DTE Insight Program.

8

9 **Q10. Are you sponsoring any exhibits in this proceeding?**

10 A10. Yes. I am sponsoring in whole, or in part, the following exhibits:

11	Exhibit	Schedule	Description
12	A-12	B5.6	Capital Expenditures – Demand Response Portfolio
13			and DTE Insight
14	A-12	B5.6.1	C&I Battery Storage Pilot Document
15	A-12	B5.6.2	Residential Generator Pilot Document
16	A-12	B5.6.3	Vehicle-to-Home Pilot Document
17	A-12	B5.6.4	Smart Charge Pilot Document
18	A-13	C5.9	Demonstrating and Selling Expenses-DR (line 9)

19

20 **Q11. Were these exhibits prepared by you or under your direction?**

21 A11. Yes, they were.

22

23 **Q12. How is your testimony organized?**

24 A12. My testimony consists of the following seven parts:

25 Part I Demand Response Overview

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1	Part II	Regulatory Framework
2	Part III	DR Portfolio
3	Part IV	DR Portfolio Investments
4	Part V	Evolving DR Landscape
5	Part VI	DTE Insight Program

6

7 **Part I: Demand Response Overview**

8 **Q13. What is the purpose of Demand Response (DR)?**

9 A13. DR is designed to reduce or shift enrolled customers' energy usage during periods
10 of high demand. DR programs provide an opportunity for customers to reduce or
11 shift their electricity usage during periods of high energy demand in response to
12 rates or other forms of incentives.

13

14 **Q14. What are the benefits to customers for participating in DR programs?**

15 A14. DR programs allow electric customers to play a role in the operation of the electric
16 grid and support the clean energy transition. Customers participating in DR
17 programs or tariffs can benefit from lower bills and/or incentives when utilizing
18 these programs. All customers, whether they participate or not, benefit from the
19 cost savings that DR provides. This is because as the demand for power decreases,
20 less efficient or more expensive forms of generation are not needed.

21

22 **Q15. What are the benefits of DR to the utility?**

23 A15. The reduction or shift in customer usage from DR programs can provide value to
24 the utility by reducing the need for additional generation, resulting in lower energy
25 costs and supporting the Company's generation transformation. If DR programs are

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1 less costly than other capacity resources, the utility and all customers can benefit
2 from displacing or deferring the need for new generation resources. In addition,
3 reducing electricity usage when demand is the highest can result in lower wholesale
4 energy prices.

5

6 **Part II: Regulatory Framework**

7 **Q16. What is the regulatory framework adopted by the Commission to approve,**
8 **recover, and reconcile expenditures in the Company's DR portfolio?**

9 A16. In the September 15, 2017, Order in Case No. U-18369, the Commission approved
10 a 'three-phase' approach for the approval, recovery, and reconciliation of DR
11 expenditures. In the first phase, DR proposals are evaluated in the context of an
12 integrated resource plan (IRP). In the second phase, DR plans that were approved
13 as part of the IRP are considered pre-approved and the associated costs are included
14 in rates in the utility's future general rate cases. The utility can also propose changes
15 or modifications to DR programs or pilots at this time. The IRP DR proposed
16 programs and pilots, as well as any changes, are then evaluated and approved in
17 rate cases and can be considered for inclusion in the next IRP. The third phase
18 involves a reconciliation of DR costs, participation rates, and demand savings
19 achieved on an annual basis. The Commission also stated that during the
20 reconciliation proceedings, actual capital spending in the examination period will
21 be reconciled against the amount approved in the IRP and recovered in a rate case
22 while Operation and Maintenance ("O&M") spending will be reconciled against
23 the amount approved and recovered in a general rate case.

24

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1 In addition, the Company can earn a financial incentive through a financial
2 incentive mechanism (FIM) calculated in each annual reconciliation case. The FIM
3 methodology was agreed upon in the settlement of the 2019 DR Reconciliation
4 (Case No. U-20793).

5
6 **Q17. What DR capital costs were pre-approved through settlement in the**
7 **Company's most recent IRP?**

8 A17. Table 1 shows the capital costs that were pre-approved through settlement in the
9 Company's last IRP Order, Case No. U-21193, issued July 26, 2023.

10

11 **Table 1 U-21193 Pre-approved DR Capital Expenditures**

Program	2024	2025
CoolCurrents	\$500,000	\$500,000
SmartCurrents	\$2,500,000	\$2,500,000
Commercial & Industrial Dashboard	\$350,000	\$350,000
Interruptible Water Heating	\$1,000,000	\$1,000,000
Total	\$4,350,000	\$4,350,000

12

13 **Part III. DR Portfolio**

14 **Q18. Could you describe the Company's current DR portfolio?**

15 A18. Yes. DTE Electric develops and manages its DR programs offering customers a
16 range of options consisting of products, customer incentives, tariff structures, and
17 education based on their profiles and willingness to curtail or shift energy usage
18 during peak hours. As part of the development process, the DR organization

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1 evaluates customer behavior, program acceptance and validates technologies that
2 can deliver benefits to its customers.

3
4 The Company's current DR portfolio is made up of eleven tariffs and programs and
5 four pilots that are available to residential, commercial and industrial customers.
6 The goal of the Company's DR portfolio is to deliver measurable peak demand
7 reduction by effectively engaging customers to manage and reduce or shift their
8 energy consumption.

9

10 **Q19. What measurable value does the DR portfolio provide?**

11 A19. The Company currently registers DR as Load Modifying Resources (LMR) at
12 MISO and receives capacity credit for its established DR portfolio.

13

14 **Q20. What programs and tariffs are included in the Company's current DR**
15 **portfolio?**

16 A20. The Company's DR portfolio is made up of CoolCurrents™, SmartCurrents™,
17 Smart Savers, Interruptible Water Heating, Dynamic Peak Pricing (DPP) and
18 multiple interruptible tariff rates for Commercial and Industrial (C&I) customers.
19 The participants in the DR programs or on the tariffs receive a discounted rate or
20 incentive in exchange for reducing their load during DR events.

21

22 **Q21. What is a DR event?**

23 A21. A DR Event is a period of high energy demand when programs are activated to
24 relieve stress on the grid.

25

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1 **Q22. What is the CoolCurrents Program?**

2 A22. CoolCurrents is the program name for the Interruptible Space Conditioning tariff
3 (Rate D1.1) that is available to residential and commercial customers. Customers
4 who enroll in CoolCurrents are equipped with a direct load control device (LCD)
5 on their air conditioning unit(s) or central heat pump that allows the Company to
6 cycle the associated appliance in exchange for a discounted rate. The cycling of the
7 appliance is limited to no more than eight hours in any 24-hour period and events
8 can be called year-round in any of the four MISO seasons.

9

10 **Q23. What is the SmartCurrents Program?**

11 A23. The SmartCurrents Program, commonly referred to as the Programmable
12 Communicating Thermostat (PCT) Program, is a DR offering where residential and
13 commercial customers receive a free ecobee premium thermostat. By enrolling in
14 SmartCurrents and installing their free thermostat, customers agree to allow the
15 Company to adjust the thermostat setpoint by up to four degrees during
16 SmartCurrents events. SmartCurrents events can occur on non-holiday weekdays
17 between the hours of 12:00 pm and 8:00 pm, can last no more than four hours and
18 are limited to 64 total hours each calendar year, and available year-round.

19

20 **Q24. What is the Smart Savers program?**

21 A24. The Smart Savers program, which is a Bring Your Own Device (BYOD) program,
22 is available to residential and commercial customers who have an existing and
23 eligible PCT installed at their residence or business. In this program, customers
24 enroll their eligible thermostat in the program and agree to let the Company adjust
25 the setpoint on the thermostat up to four degrees during Smart Savers events. Smart

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1 Savers events last no more than four hours and can be called between 12:00 pm and
2 8:00 pm on non-holiday weekdays. The Smart Savers season runs from June 1st
3 through September 30th and events are limited to 56 total hours annually.
4

5 **Q25. What is the Interruptible Water Heating rate?**

6 A25. The Interruptible Water Heating rate (D5) is available to both residential and
7 commercial customers that use hot water for sanitary purposes or other uses subject
8 to the approval of the Company. An LCD is installed at the customer's location that
9 turns off the heating element of the water heater for up to four hours in any 24-hour
10 period during any MISO season. Participating customers receive a discounted rate
11 on the associated water heating usage.
12

13 **Q26. What is the DPP rate?**

14 A26. The DPP rate (D1.8) is a rate that is offered to residential and commercial
15 customers. It is a three-tiered Time of Use rate (On-Peak, Mid-Peak, and Off-Peak),
16 with a critical peak pricing (CPP) rate component. During a CPP event, which are
17 available year-round in any of the four MISO seasons, the price per kilowatt of
18 electricity increases to \$0.95 per kilowatt hour. CPP events occur between 3:00 pm
19 and 7:00 pm on non-holiday weekdays and are limited to no more than 56 hours
20 per year.
21

22 **Q27. What additional interruptible tariffs does the Company offer to C&I**
23 **customers to promote participation in demand response?**

24 A27. The Company offers C&I customers six tariffs at a discounted rate in exchange for
25 agreeing to interrupt a portion of their electric load during DR events. Unless

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1 otherwise noted, these tariffs are available for interruption year-round in any of the
2 four MISO seasons. The tariffs that are available to C&I customers are as listed:

3

4 1. Interruptible General Service Rate (D3.3): Commercial secondary customers can
5 elect to have separately metered service that is subject to interruption or establish a
6 portion of their load as firm through the product protection feature. This rate is not
7 available to customers whose loads are primarily off-peak. Company interruptions
8 may include interruptions for, but not limited to, maintaining system integrity,
9 economic reasons, or when available system generation is insufficient to meet
10 anticipated system load.

11 2. Interruptible Supply Base Service Rate (D8): Primary voltage customers who desire
12 separately metered service for a specified quantity of demonstrated interruptible
13 load of not less than 50 kW at a single location can take service under this rate.
14 Customers may be ordered to interrupt only when the Company finds it necessary
15 to do so either to maintain system integrity or when the existence of such loads will
16 lead to a capacity deficiency.

17 3. Alternative Electric Metal Melting (Rider 1.1): Customers who operate electric
18 furnaces for the reduction of metallic ores and/or electric use consumed in holding
19 operations who provide special circuits can have that load separately metered,
20 making it subject to interruption. The Company may order an interruption to
21 maintain system integrity.

22 4. Electric Process Heat (Rider 1.2): Customers who use electric heat as an integral
23 manufacturing process, or electricity as an integral part of anodizing, plating, or a
24 coating process and who provide special circuits can have that load separately

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1 metered, making it subject to interruption. The Company may order an interruption
2 to maintain system integrity.

3 5. Interruptible Supply Rider (Rider 10): Rider 10 allows customers to elect the
4 amount of interruption they are willing to take under a separate meter. Program
5 participation is capped at a total of 650 MW of enrolled load. Rider 10 is designed
6 for customers of greater than 50 MW at a single location, although at the
7 Company's discretion, and with available capacity, the minimum site requirements
8 can be waived. The Company may order an interruption to maintain system
9 integrity.

10 6. Capacity Release (Rider 12): Customers are provided a capacity release payment
11 by subscribing at least 100 kW of load per site location for interruption. The
12 Company may order an interruption to maintain system integrity. The program is
13 only available during the MISO summer season from June 1 – August 31 although
14 the Company is evaluating customer reception for Rider 12 to be made available
15 for the other seasons as well.

16

17 **Q28. How much capacity does the Company's existing DR portfolio account for in**
18 **meeting MISO's resource adequacy requirements?**

19 A28. The 2023/2024 MISO Plan Year was the first year that MISO used a seasonal
20 construct, as opposed to yearly, in establishing resource adequacy requirements.
21 This change is discussed further in Part V. MISO's resource adequacy construct
22 has four seasons; Summer (June, July and August), Fall (September, October,
23 November), Winter (December, January, February) and Spring (March, April,
24 May). DTE Electric registered 831 MWs (installed capacity or ICAP) of demand
25 response for the summer season, equating to 912 Zonal Resource Credits (ZRCs).

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1 The seasonal breakdown of ICAP MWs and ZRCs used to meet resource adequacy
2 requirements in Planning Year 2023/24 is in Table 2.

3

4

Table 2 2023/24 ICAP MWs (ZRCs) by Season

Summer	Fall	Winter	Spring
831 (912)	368 (431)	363 (465)	318 (403)

5

6 **Q29. How does the Company's DR portfolio compare to other utility DR portfolios?**

7 A29. In 2022, the U.S. Energy Information Administration (EIA) ranked DTE Electric's
8 DR portfolio the fifth largest in the country in terms of Potential Peak Demand
9 Savings. EIA also ranked the Company's portfolio as the largest in MISO in terms
10 of Potential Peak Demand Savings.

11

12 **Q30. What is the intent of the DR pilot offerings?**

13 A30. Pilots are potential programs focused on understanding technology or design and
14 determining whether they can become full-scale programs that will deliver
15 accountable peak demand reductions or shifts in energy consumption. The
16 Company will determine which pilots may become programs in the DR portfolio
17 on a case-by-case basis.

18

19 **Q31. Why is it important to continue to invest in DR pilots?**

20 A31. Continued investment in DR pilots allows the Company to stay at the forefront of
21 new or emerging DR technologies and evaluate whether the technologies or
22 program design will provide benefits to the Company and its customers. Investment

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1 in DR pilots also can shape future designs of programs and provide valuable
2 learnings as the DR landscape changes.

3

4 **Q32. What DR pilots is the Company developing or conducting to continue to**
5 **diversify the portfolio as well as offer more options for potential DR**
6 **customers?**

7 A32. The Company is conducting pilots that include an electric vehicle (EV) DR pilot
8 (Smart Charge), a residential home generator pilot, and a C&I Battery storage pilot.
9 The Company is also developing a Vehicle-to-Home (V2H) pilot. These pilots will
10 be discussed in detail later in my testimony.

11

12 **Q33. What is the overall purpose of continued investment in DR?**

13 A33. DR programs are, and will continue to be, an important part of DTE Electric's
14 integrated resource portfolio and are part of a utility system framework within the
15 comprehensive context of an IRP process. The Company has been managing and
16 investing in a diverse range of programs and pilots that serve as resources in the
17 Company's IRP.

18

19 Changes have been occurring in the energy landscape including energy legislation,
20 regulatory framework, and environmental regulations. These changes, coupled with
21 a shift from fossil fuel-based generation to cleaner energy resources, are driving
22 investment in a DR portfolio to help meet the Midcontinent Independent System
23 Operator's (MISO) resource adequacy requirements. A portfolio of pilots and
24 programs enables the Company to continue providing secure, reliable, and

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1 sustainable energy supply to its customers under a changing generation capacity
2 and energy landscape.

3

4 **Part IV: DR Portfolio Investment**

5 Projected Capital

6 **Q34. How much capital is the Company forecasting to invest in the DR portfolio**
7 **during the bridge year, January 1, 2023, through December 31, 2024, and the**
8 **forecasted test year, January 1, 2025, through December 31, 2025?**

9 A34. As shown in Exhibit A-12 B5.6 p1, during the bridge period the Company is
10 forecasting to invest \$2.2 million on the CoolCurrents Program, \$8.3 million on the
11 SmartCurrents program, and \$6.9 million on other DR programs and pilots. In
12 addition, during the forecasted test year the Company is forecasting to spend \$0.5
13 million on CoolCurrents, \$2.5 million on SmartCurrents and \$1.4 million on other
14 DR programs and pilots. In total, the Company is forecasting DR capital
15 investments of \$17.4 million during the bridge period and \$4.4 million during the
16 forecasted test year.

17

18 **Q35. What is the status of the Company's CoolCurrents LCD replacement**
19 **program?**

20 A35. As of December 31, 2023, approximately 260,000 residential customers and over
21 800 commercial customers take service on the D1.1 rate. The Company began
22 replacing outdated legacy Radio Control Units (RCUs) in 2015 after identifying
23 that the legacy RCUs were in need of repair, prone to malfunctioning, and difficult
24 to service as some units were installed as early as the 1980's. Since then, the
25 Company has successfully replaced an estimated 170,000 legacy RCUs with a two-

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1 way communicating 24v LCD. The replacement LCD provides the Company with
2 increased flexibility to interrupt based on geographic area or other subgroups as
3 well as determine whether devices are online and available for interruption or
4 offline.

5
6 Throughout 2023, the Company focused on continuing to replace RCU devices as
7 well as investigating previously installed LCDs that are offline. Nearly 25,000
8 previously installed replacement LCDs (out of 170,000) are no longer joined to the
9 electric meter and thus not available for interruption. Based on the field
10 investigations conducted in 2022 and 2023, around 70% of the replacement LCDs
11 investigated are due to the customer wiring no longer supplying the required 24v.
12 Other reasons for offline devices are unrecorded meter changes or a device reset
13 required due to a meter firmware upgrade. Making better use of data analysis and
14 procedures for upgrading meters, DTE Electric is working to reduce the need for
15 field investigations of offline devices.

16

17 **Q36. Could you explain the status of the remaining CoolCurrent customers?**

18 A36. Yes. Approximately 90,000 CoolCurrent customers still have legacy RCUs
19 primarily due to not having the proper wiring in place to power a replacement LCD.
20 Without the proper wiring available to provide power to the 24v LCD, the LCD
21 will not be installed. To address this issue the Company is evaluating the
22 installation of an alternative new LCD.

23

24 **Q37. How does installing an alternative new LCD provide a solution to customers**
25 **that do not have the proper wiring needed to support a replacement LCD?**

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1 A37. The replacement LCD, like the older RCUs, relies on a 24v line that is run from the
2 customer's furnace for power. The Company has found that when a customer
3 services or replaces their heating, ventilation, and air conditioning (HVAC) unit,
4 this line is often not reattached or is simply removed. To replace or repair the 24v
5 line, it is estimated that a customer would have to pay a contractor, on average,
6 between \$80 to \$200 to make the replacement LCD functional. This is also
7 comparable to what a customer with a legacy RCU would spend to ensure the
8 proper wiring is in place for a replacement LCD.

9

10 The alternative 240v LCD connects directly to the customer's HVAC unit and pulls
11 its power from the unit making the 24v line no longer necessary. By offering this
12 alternative LCD, CoolCurrents customers can remain enrolled in the program
13 without any additional cost, as the device is not dependent on a dedicated, customer
14 supplied separate 24v line.

15

16 **Q38. Has the Company worked with any other utilities to gather learnings about**
17 **the alternative 240v LCD?**

18 A38. Yes. The Company had discussions with Consumers Energy (CMS), who use a
19 similar 240v LCD, to better understand how the alternative LCD is installed and
20 operates. This included an installation go and see by the Company's field personnel
21 with CMS field installers. The go and see allowed the Company's field personnel
22 to see the alternative LCD installation process as well as learn what type of
23 equipment and components are needed and to ask questions directly to experienced
24 installers. In addition, the CoolCurrents Program Manager discussed the alternative
25 LCD with the CMS Program Manager to gather further learnings from their

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1 experiences. After the collaborative field events conducted with CMS installers,
2 DTE Electric field service personnel determined that similar devices could be
3 installed by the Company's personnel. DTE Electric field service trainers are
4 currently developing a training course which all field service representatives are
5 anticipated to complete in the second quarter of 2024.

6

7 **Q39. Has the Company ordered any alternative LCDs that do not require a 24v**
8 **line?**

9 A39. Yes. In 2023, the Company ordered and accepted delivery of nearly 5,000
10 alternative LCDs that are targeted to be installed in 2024. In addition, the Company
11 has ordered the various components that are necessary for the installations. The
12 installation of the alternative LCD devices will be used to gauge whether this is a
13 viable solution for customers who do not have the proper 24v wiring. Assuming
14 that there is a willingness on the part of customers to have the alternative 240v LCD
15 installed on their appliance, and DTE Electric field service executes requested
16 installations as anticipated; this device will likely provide a satisfactory alternative
17 to the 24v device.

18

19 **Q40. How is the Company selecting which CoolCurrents customers may receive the**
20 **alternative LCD?**

21 A40. These alternative devices will initially be offered to customers that are currently
22 enrolled in the CoolCurrents program, allowing them to remain in the program
23 without the need to hire a contractor to repair their 24v line. As per the D1.1 rate,
24 CoolCurrents customers have a separate meter to record AC or heat pump
25 consumption. In January 2024, the Company initially targeted approximately 200

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1 customers, located on the Fisher substation, who were contacted in 2022 to repair
2 the 24v wiring and do not currently have the 24v connection required to support the
3 replacement LCD. This initial 200 customer targeted effort supports the Non-Wires
4 Alternative (NWA) pilot in collaboration with DTE Electric's Distribution
5 Operations team. Beginning in March 2024, the Company will contact
6 approximately 4,000 customers, and more if needed, in two batches of around 2,000
7 customers, who do not have a 24v connection.

8

9 **Q41. How will the Company determine if the alternative LCD provides a solution**
10 **to customers that are offline and/or without the proper voltage?**

11 A41. To determine if the alternative LCD is a viable solution the Company will consider
12 customer acceptance, ease of installation, and functionality of the alternative LCD.

13

14 **Q42. What actions will the Company take if a CoolCurrents customer refuses the**
15 **alternative LCD and does not have the proper wiring?**

16 A42. If a customer continues to be non-compliant even after being offered an alternative
17 LCD, they will be removed from the tariff and other DR programs, such as Smart
18 Savers or SmartCurrents, will be marketed as alternative DR programs to maintain
19 their support of DR programs.

20

21 **Q43. Could you describe the capital investment of \$2.2 million in the CoolCurrents**
22 **program during the bridge year and of \$0.5 million in the forecasted test year?**

23 A43. The capital investment through 2025 will be used to order and install alternative
24 LCDs to address customers who do not have the proper wiring in place. In addition,
25 the investment will support continued investigations into offline devices, install

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1 new or replacement LCDs and program operation costs. The capital investment for
2 the CoolCurrents Program can be seen on Line 1 of Exhibit A-12, Schedule B5.6.

3

4 **Q44. Why is the Company continuing to make these improvements?**

5 A44. The Company identified that replacing the outdated infrastructure results in a higher
6 capacity value through increased capabilities and effectiveness. The LCDs are two
7 way communicating devices providing the Company the capability to determine
8 whether devices are available for interruption. They also provide flexibility to
9 interrupt at substation or circuit level. With continued investment in the
10 CoolCurrents program, DTE Electric can extend the equipment life and continue to
11 provide an additional DR program option for residential and commercial
12 customers. In addition, the CoolCurrents program is a direct load control DR
13 program that doesn't allow for customer opt outs adding additional value to the
14 Company's DR portfolio and further supports resource adequacy.

15

16 **Q45. What changes has the Company made to the SmartCurrents program?**

17 A45. In August of 2023, SmartCurrents was relaunched with changes to the program.
18 One of the changes included the separation of the program from the DPP rate. Other
19 changes included upgrading the thermostat to an ecobee Premium Thermostat,
20 providing an annual participation incentive to increase retention, and revising the
21 DR event parameters to increase the flexibility and availability of SmartCurrents as
22 a MISO LMR resource. While the program was being redesigned to incorporate
23 these changes, program recruitment was paused.

24

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1 **Q46. Why did the Company think separating the SmartCurrents program from the**
2 **DPP rate was necessary?**

3 A46. Separating the SmartCurrents program from the DPP rate responds to feedback
4 heard directly from customers in an ad hoc quantitative survey to understand how
5 they would rate select attributes of the SmartCurrents program. In addition, this
6 change allows customers to select the rate that best fits their household and lifestyle.
7 Removing the tariff requirement also opened eligibility to customers who
8 previously may have been denied enrollment due to tariff incompatibilities. In
9 addition, this change allowed the Company to make the necessary changes to the
10 event parameters to better align with the Company's other DR programs.

11

12 **Q47. Have the program changes had an impact on customer enrollment since the**
13 **relaunch in August of 2023?**

14 A47. Yes. Since relaunch, the program has enrolled a net 7,820 customers as of
15 December 31, 2023, which is 29% of all program enrollees currently active as of
16 the same date.

17

18 **Q48. Could you describe the \$8.3 million bridge year capital investment and \$2.5**
19 **million test year capital investment into the SmartCurrents Program?**

20 A48. The Company is projecting to grow the cumulative number of enrolled thermostats
21 from approximately 27,000 as of December 31, 2023, to 35,000 enrolled
22 thermostats at the end of 2024 and 40,000 at the end of 2025. Towards the end of
23 2022 and through the first half of 2023, the Company redesigned the SmartCurrents
24 program. As noted above, the redesign included the removal of the DPP rate
25 requirement, as well as adjusting the callable event hours and adding an annual

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1 incentive to the program. The multitude of changes in the redesign required updates
2 to program management, IT processes, data transfers, marketing materials, and
3 installation training, thus contributing to the increased costs over the bridge period.
4 The Company also chose to update the thermostat offering to a newer model, the
5 ecobee Smart Thermostat Premium. The new ecobee Smart Thermostat Premium
6 comes with a smart sensor and offers additional functionality such as indoor air
7 quality monitoring and can deliver personalized energy recommendations.

8
9 In 2024, the Company is projecting to spend approximately \$4.0 million primarily
10 on contractor costs and materials. Beginning in 2025, the Company is forecasting
11 to spend \$2.5 million to support the SmartCurrents Program. The continued
12 investment in the SmartCurrents program will ensure the continued success of the
13 program, support the Company's program enrollment goals and increase the MW
14 capacity. The capital investment in the SmartCurrents Program can be seen on Line
15 2 of Exhibit A-12, Schedule B5.6.

16
17 **Q49. Can you provide a further breakdown of the SmartCurrents capital costs?**

18 A49. Capital costs associated with the SmartCurrents Program consist of primarily of
19 contract labor and materials. Contract labor is provided by ICF and EnergyHub,
20 and materials consists of the ecobee device costs and associated API license. In
21 addition, there is internal DTE Electric labor to support the program, that includes
22 program management, internal IT labor and digital assistance. ICF assists in the
23 management of the SmartCurrents program in many facets including, but not
24 limited to, thermostat scheduling, installation and reporting, program management,
25 recordkeeping, IT support, customer communication and marketing development,

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1 as well as coordinating thermostat purchases. ICF supported the program redesign.
2 EnergyHub is the third-party integrator and their platform that is used communicate
3 with the enrolled thermostats which includes determining if the thermostat is online
4 and dispatching event notifications to host thermostats and making the temperature
5 offset when a DR event is called.

6

7 **Q50. What changes has the Company made to the SmartCurrents program in an**
8 **effort to reduce program costs?**

9 A50. Some of the changes made to reduce program costs include:

- 10 • When a customer selects professional installation at the time of enrollment, rather
11 than shipping the thermostat to the customer, the installer brings the thermostat to
12 the customer's residence during the installation appointment. This eliminates the
13 shipping costs and materials for customers selecting professional install at the time
14 of enrollment. Since relaunch through the end of 2023, approximately 54% of
15 customers elected professional installation.
- 16 • The Company added virtual installation as a new installment option which saves,
17 on average, \$80 compared to an in-person professional installation appointment.
18 This provides a virtual agent to help walk through thermostat installation with the
19 customer, ensuring proper connection and not requiring or reducing an in-person
20 installation. Since relaunch, 7% of customers opt for virtual installation at the time
21 of enrollment as of year-end 2023.
- 22 • A new installation scheduler tool is offered that provides customers with the ability
23 to schedule their own installation appointment, rather than having to contact the
24 call center to do so. This tool also has a chat function that provides customers with

Line
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1 troubleshooting support, reducing the need for service calls. As of December 31,
2 2023, customers have scheduled 40% of their own appointments since the relaunch.
3 • When a customer returns a thermostat, they are provided a return label via email
4 versus being mailed a return label, reducing postage costs.

5
6 **Q51. Has the Commission been supportive of the SmartCurrents Program in**
7 **previous filings?**

8 A51. Overall, yes. While MPSC Staff generally supports the program, it was agreed upon
9 in the 2021 DR Reconciliation settlement, Case No. U-21242, to disallow
10 \$1,672,895 in capital expenses associated with the SmartCurrents Program. The
11 MPSC Staff recommended the disallowance citing that the program was only
12 preapproved for \$3 million in 2021 through Case No. U-20471 (the Company's
13 2019 IRP). The disallowance (~\$1.7 million) is the difference between the actual
14 spend on SmartCurrents in 2021 and \$3.3 million (\$3 million plus 10%).

15
16 **Q52. What reasons did Staff cite in recommending the disallowance?**

17 A52. The Staff did not find the overspend to be reasonable because of the lack of value
18 of these costs demonstrated by the Utility Cost Test. The SmartCurrents spend over
19 the authorized amount was primarily attributed to creating a new webpage to
20 redesign, enhance, and streamline the potential and existing participant customer
21 journey. Specifically, the webpage and platform allowed for self-service
22 enrollment, unenrollment and management of DPP event communication
23 preferences. At the time of the 2021 DR reconciliation filing, the Company could
24 not correlate increased enrollments and event participation to the development of
25 the new webpage.

Line
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1

2 **Q53. Is the Company requesting recovery for the \$1,672,895 that was originally**
3 **disallowed in the 2021 DR reconciliation?**

4 A53. Yes. Although the Company properly eliminated the disallowed capital from the
5 balance sheet Exhibit A-2, Schedule B6.1, the Company believes there are benefits
6 from these costs and that it should be allowed to recover them. If the Commission
7 approves the Company's request for recovery, \$914,448¹ should be added to the
8 projected test year rate base.

9

10 **Q54. Does the Company have any updated metrics that can be directly attributed**
11 **to the 2021 spend on the platform and webpage development for the**
12 **SmartCurrents program?**

13 A54. Yes. The Company did recognize an increase in conversion rate from 14% to 46%
14 and the average time to process enrollments decreased from an average of seven
15 days to one day. Looking back, the number of customers who enrolled in
16 SmartCurrents from August 21, 2020, through August 20, 2021, was 6,736. After
17 the webpage went live in 2021, 10,120 customers enrolled within the same
18 timeframe over the next year, resulting in a 50% increase in enrollments. Since the
19 program's 2023 relaunch, 98% of customers have enrolled through the self-service
20 channel that was set up in 2021. This supports the investments the Company made
21 in 2021 to the SmartCurrents program, specifically to the platform and the webpage
22 development, provided value to the program and the \$1,672,895 of disallowed
23 capital should be considered reasonable and prudent and therefore recoverable.

24

¹ The amount is based on a January 1, 2025, balance of \$1,081,737 and December 31, 2025, balance of \$747,158; \$334,579 should be added to depreciation expense.

Line
No.

1 **Q55. How much capital is the Company forecasting to invest in Other Demand**
2 **Response Programs and Pilots?**

3 A55. As can be seen on Exhibit A-12, B5.6, the Company is forecasting to spend \$6.9
4 million in capital during the 24-month bridge period ending December 31, 2024,
5 and \$1.4 million during the forecasted test year ending December 31, 2025, in Other
6 Demand Response Programs and Pilots.

7
8 **Q56. What capital investments are included in Other Demand Response Programs**
9 **and Pilots?**

10 A56. The Other DR Programs and Pilot category on Exhibit A-12, Schedule 5.6, line 3
11 includes both pre-approved programs from DTE Electric's most recent IRP
12 settlement, Case No. U-21193, and existing on-going pilots. In the Company's
13 settlement of Case No. U-21193, the capital associated with C&I Dashboard and
14 Interruptible Water Heating replacement programs were pre-approved and are
15 included in this capital investment amount. The current pilot that the Company is
16 evaluating that has associated capital spend beyond what was included in the IRP
17 for pre-approval is the C&I Battery Pilot.

18
19 **Q57. What is the C&I Dashboard that was pre-approved in Case No. U-21193?**

20 A57. The Company issued a Request for Proposal in 2023 and is successfully partnering
21 with Enel X North America, Inc. as a result to provide certain C&I interruptible
22 customers, likely customers taking service under D8, R10 or R12, with technology
23 to help improve their DR performance during called events. These tariffs represent
24 439 MW (80% of the MWs available during the MISO 2023/24 summer season) so
25 their performance is critical to reliability. The technology provides customers with

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1 near real-time telemetry meter data so that a DR event can be monitored prior to,
2 during, and after it occurs. The data is displayed on a dashboard that is accessible
3 by both the customer and the Company. Providing customers with near real-time
4 telemetry will better equip them to curtail load during DR events in accordance
5 with their contracted load reduction value. The technology also provides the
6 Company analytics for better DR forecasting and post-event analysis. Initially, the
7 Company plans to provide the dashboard to interested customers for up to 55
8 customers' sites, and add up to 10 new sites in 2025, although it is anticipated that
9 the number of sites may increase as the Company gains hands-on experience with
10 the dashboard. It is anticipated that the first customers will have the necessary
11 equipment installed and access to the dashboard in the first half of 2024.

12

13 **Q58. How much capital does the Company anticipate spending on the C&I**
14 **Dashboard over the bridge period ending December 31, 2024, and the**
15 **forecasted test period ending December 31, 2025.**

16 A58. The Company anticipates spending \$1.0 million during the bridge period to support
17 the setup of the customer sites and provide access to the dashboard and \$350,000
18 during the forecasted test period to continue access to the dashboard for current
19 customers and add additional customer sites.

20

21 **Q59. Could you describe the capital investment in the Interruptible Water Heating**
22 **program?**

23 A59. Yes. Similar to the CoolCurrents Program, the Company's LCDs that operate the
24 Interruptible Water Heating program and reside in customers' homes are no longer
25 functioning as intended and are due for an upgrade. The Company plans to begin

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1 replacing water heating LCDs for customers taking service on D5 (approximately
2 45,000) in 2024. The Company purchased 864 new water heating LCDs in 2023
3 with plans to purchase an additional 864 LCDs in 2024, equating to a total of 1,728
4 new units. The Company will leverage the learnings from the CoolCurrents LCD
5 replacement program including notifying customers of the work that will be
6 performed, educating customers on the rate discount as well as preemptively
7 reaffirming customers desire to remain in the program prior to sending a field
8 service installer to perform the work. If a customer does not wish to remain in the
9 Interruptible Water Heating program, they will be removed from the rate and a new
10 LCD device will not be installed in their home. After the initial targeted
11 replacements are performed in 2024, the results will be evaluated with the
12 expectation that installations will increase in subsequent years.

13

14 **Q60. Is 24v wiring required, similar to the Company's CoolCurrents replacement**
15 **LCDs?**

16 A60. No. There is no need for a separate 24v power supply with interruptible water
17 heating services. The control unit is wired directly to the power source in the
18 dedicated meter enclosure and therefore does not need a separate power source.

19

20 **Q61. How much is the Company forecasting to spend on this program during the**
21 **bridge period ending December 31, 2024, and during the forecasted test period**
22 **ending December 31, 2025?**

23 A61. The forecasted capital investment associated with the Interruptible Water Heating
24 program is included in the Other Demand Response Programs and Pilots category
25 on Line 3 of Exhibit A-12, Schedule B5.6. The Company is forecasting to spend

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1 \$345,197 in capital during the bridge period and \$500,000 in capital to support
2 customer LCD installations during the forecasted test period, which is less than the
3 \$1,000,000 that was pre-approved in the IRP settlement as the Company ramps up
4 the replacement LCD installations.

5

6 **Q62. What is the C&I Battery Storage pilot?**

7 A62. The C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate
8 battery energy storage system (BESS) that will be located at two customers' sites.
9 It is designed to test the ability to achieve peak demand shaving or shifting during
10 DR events. The Company is targeting a two-year pilot period following installation
11 and commissioning of the batteries. Refer to Exhibit A-12, B5.6.1 for additional
12 detail on this pilot.

13

14 **Q63. Can you discuss the main objectives of the C&I Battery Storage pilot?**

15 A63. Yes. The main objectives of the pilot are as follows:

- 16 • Engage with customers to better understand their interest in hosting and
17 potentially operating a BESS;
- 18 • Gain operational experience on battery installation, management, and
19 control interfaces when the system is located at a customer's site as opposed
20 to a Company site;
- 21 • Assess feasibility for sharing asset control between customer and the
22 Company; and
- 23 • Evaluate the effectiveness of the BESS to achieve system peak demand
24 reduction when a demand response event is called by the Company;

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- 1 • Assess customer's actions to achieve demand charge and overall bill
- 2 reductions;
- 3 • Facilitate the understanding of multiple energy storage values,
- 4 compensation models, and the integration of battery storage in wholesale
- 5 markets to support tariff development as contemplated by the
- 6 Commission's Order in MPSC Case No. U-21032.

7

8 **Q64. Could you describe the status and progress of the C&I battery pilot?**

9 A64. Both batteries have been ordered, shipped from China, and have arrived in the US.
10 The switchgear component, which has an approximate 38-week lead-time, was
11 approved in December 2023, and both switchgears were ordered on December 27,
12 2023. Hitachi will be working on the detailed design portion of the project in the
13 first quarter of 2024.

14

15 As part of the implementation plan, the Company has identified one customer. The
16 Company intends to leverage the commercial agreement developed and agreed
17 upon by the first participant as a template for the agreement between the second
18 participant. Due to lead time of major equipment, installation at the first customer's
19 site has taken longer than anticipated, although is targeted for Q2 2025. The
20 Company is confident that a second participant will be identified in partnership with
21 Company's MAS group in the first half of 2024 and that the second battery will be
22 installed shortly after the first. Once the second customer has been identified and
23 the first installation is underway, the installation of the second battery will begin.
24 The Company plans for both batteries to be operational by the end of 2025. The
25 initial proposed event schedule includes no more than 30 planned DR events per

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1 year and five emergency DR events, with a least one-hour customer notice, per
2 year. However, per the order in Case No. U-21297, the Company will meet with
3 the MPSC Staff to discuss an appropriate number of required test events each year.
4

5 **Q65. Did the Commission approve all capital costs related to the C&I battery pilot**
6 **in Case No. U-21297?**

7 A65. No. In Case No. U-21297, the Commission excluded approximately \$2.0 million
8 (\$1,990,360) of the capital spend on the C&I battery pilot because the Company
9 did not intend on signing up a second customer until the first battery was installed
10 and did not provide a timeline; thus, Staff did not believe that half the capital would
11 be used and useful in the projected test year. In 2022, the Company spent \$2.5
12 million in capital to procure the equipment for the C&I battery pilot which was
13 partially recovered in Case No. U-21403 2022 DR Reconciliation. The exclusion
14 included \$1.25 million related to half of the procured equipment which was spent
15 during the bridge period (2022) and \$0.75 million in forecasted test year (2023)
16 spend.
17

18 **Q66. Does the Company believe that Staff's concern remains in this instant case?**

19 A66. No. As stated above, the Company expects to have a second customer secured in
20 the first half of 2024 with both batteries operational by the end of 2025, and as such
21 is requesting the previously excluded costs as mentioned above.
22

23 **Q67. How much capital does the Company anticipate spending on the C&I Battery**
24 **pilot over the bridge period ending December 31, 2024, and the forecasted test**
25 **period ending December 31, 2025.**

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1 A67. The Company anticipates spending \$1.4 million during the bridge period to procure
2 and install equipment and \$0.6 million in the forecasted test year to primarily
3 support final installation costs. Capital spend was moved from 2023 to 2024 and
4 2025 due to lead time of major equipment critical for progression of both batteries.

5

6 Projected O&M

7 **Q68. How much O&M is the Company forecasting to spend in 2025 on DR?**

8 A68. The Company is forecasting to spend \$5.9 million in 2025 to support the
9 development and execution of its Demand Response Portfolio. This represents a
10 \$3.2 million increase from 2022 levels (a \$0.2 million increase to account for
11 inflation and \$3 million for specific adjustments). This can be seen on Line 9 of
12 Witness Bennett's Exhibit, A-13, Schedule C5.9.

13

14 **Q69. How much O&M is needed to support the Company's Smart Savers Program**
15 **going forward?**

16 A69. The Company is projecting to grow the cumulative number of enrolled thermostats
17 from nearly 64,000 as of December 31, 2023, to more than 90,000 enrolled
18 thermostats by the end of 2025. In 2024, the Company is projecting to spend
19 approximately \$2.5 million on anniversary device fees for devices that were
20 enrolled prior to 2024. In 2024, the Company is forecasting to enroll 12,000 new
21 devices which result in additional devices fees. Beginning in 2025, the Company is
22 forecasting to spend \$3.3 million to support the Smart Savers Program. The
23 requested O&M spend is necessary to support the continued successful growth of
24 the program the Company has experienced since its inception including the annual

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1 portal fee and annual device fees, with annual devices fees increasing each year
2 based on the projected increase in enrollments.

3

4 **Q70. How much O&M is the Company forecasting to spend in Pilots and Other**
5 **Projects?**

6 A70. The Company is forecasting to spend \$2.6 million in O&M to support various DR
7 pilots, programs and projects. The pilots in this spend include the Smart Charge,
8 V2H, Residential Generator and the Non-Wires Alternative (NWA) efforts.
9 Programs such as the Company's CoolCurrents and SmartCurrents and the
10 replacement of the LCDs for the Interruptible Water Heating customers will also
11 be supported by O&M Spend. O&M spend for these programs and pilots supports
12 labor, marketing and communication efforts as well as portal, dispatch, program
13 incentive and platform fees. Other DR projects are included in this category as well.
14 The \$2.615 million in O&M is broken out by the various projects in Table 3.

15

16

Table 3 2025 Forecasted Spend

Pilot/Program/Project	Forecasted Spend
SmartCurrents	\$105,000
CoolCurrents	\$136,000
Smart Charge	\$767,000
Interruptible Water Heating	\$62,000
Residential Generator	\$161,000
Vehicle to Home	\$96,000
Non-Wires Alternative	\$18,000
Other Projects	\$1,270,000
Total	\$2,615,000

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1

2 **Q71. Could you describe the electric vehicle (EV) DR or Smart Charge pilot?**

3 A71. The initial design of Smart Charge, which launched in 2019, was to assess the
4 effectiveness of Open Vehicle Grid Integrated Platform (OVGIP) concept to
5 integrate EV charging with grid objectives through demand response. This initial
6 design ran until May of 2023.

7

8 After completion of the initial design, the Company, modified the focus of the pilot
9 to incorporate managed charging, starting in July 2023. One of the main reasons
10 the Company transitioned to managed charging was due to the mandatory roll out
11 of residential electric time of use (TOU) rates in March 2023. In this phase of the
12 pilot, the Company's managed charging approach ties each participant's enrollment
13 to their specific TOU rate schedule and automatically initiates charging to occur
14 during their off-peak rate period when it's the lowest cost for them and most
15 beneficial to the system. In addition, the Company is interested to learn if there's
16 an impact of the Company scheduling participant's daily charging automatically
17 through vehicle telematics and managed charging participation for them, or if EV
18 users are already scheduling their charging during off-peak time periods without
19 the Company's assistance. Refer to Exhibit A-12 B5.6.4.

20

21 Throughout 2023, the Company continued its partnership with Ford, General
22 Motors (GM), and BMW through the OVGIP while adding a new partnership with
23 WeaveGrid. WeaveGrid is a platform that connects utilities, original equipment
24 manufacturers (OEMs), and EV drivers and is the platform that is used to enroll

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1 eligible Tesla drivers into the Smart Charge pilot. The pilot will continue through
2 the end of 2024.

3
4 While the OVGIP is funded through the DR O&M budget, the partnership with
5 WeaveGrid was made available through the Emerging Technology Fund (ETF) that
6 was approved in Case No. U-20836². The OVGIP forecasted spend will be subject
7 to future DR reconciliation while the spend associated with WeaveGrid will not be
8 subject to future DR reconciliations.

9
10 **Q72. Could you describe the status and progress of the Smart Charge pilot?**

11 A72. Yes. In 2019, the Company worked with Electric Power Research Institute (EPRI),
12 Sumitomo, Ford, and GM. The first phase of the pilot concluded after six months
13 in August 2019 after calling 12 events with approximately 165 Ford and GM
14 employee EV drivers. The second phase of the pilot expanded beyond automotive
15 employees to any Ford and GM drivers in the Company's service territory,
16 increasing to 370 participants. DTE Electric dispatched DR events for the eight
17 months ending December 2021, resulting in 1.7 MWh of avoided energy
18 consumption during called events.

19
20 In May 2022, BMW joined the next phase with Ford and GM, which grew to 663
21 participants and called 44 DR events over the 12-month period ending May 2023.
22 The Company and OEMs identified an aggregate avoided energy total of 14 MWh
23 across all 44 events. The DR events were all two hours in length and were called
24 during different days of the week (weekdays only) and different times of the day to

² As described in Q/A 111 of Burns' Testimony (Case No. U-20836)

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1 test customer participation levels and to understand how much avoided energy the
2 Company could expect to achieve based on the number of participants enrolled.
3 The Company observed the best avoided energy results during the 12am-2am time
4 periods, since most EV owners typically charge their EV overnight, presumably
5 due to more prevalent daytime work hours and cheaper off-peak rates. The average
6 aggregated avoided energy per enrolled EV during the 12am-2am event window
7 was 1.33 kWh. The average aggregated avoided energy per participating EV during
8 the 12am-2am event window was 9.04 kWh.

9
10 Beginning in July 2023, after the conclusion for the 2022/23 pilot year, the
11 Company and OEMs had to re-recruit customers. The expansion of the pilot to
12 support managed charging required a change in terms and conditions by the OEMs.
13 As of December 31, 2023, there were 1,224 EVs enrolled in the Smart Charge pilot.
14 GM, Ford, and Tesla began enrolling customers in 2023, while BMW began
15 enrolling customers in Q1 of 2024. The Company will continue to recruit
16 customers for this pilot through 2024. Once a participant enrolls, Smart Charge
17 automatically schedules daily charging to meet their charging needs during their
18 off-peak rate times. This scheduled charging occurs on the weekdays only. The
19 Company also plans to call up to five DR events, June through September, to
20 evaluate how much demand and energy savings can be achieved.

21

22 **Q73. Is the Company planning to make Smart Charge a program within the DR**
23 **portfolio?**

24 A73. Yes. The Company believes that the Smart Charge pilot should become part of the
25 Company's DR portfolio beginning in 2025. With continued allocated O&M

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1 resources, along with the forecasted increased adoption of EVs, Smart Charge is
2 expected to continue expanding. Transitioning Smart Charge to a program also
3 allows for more customers to participate in the program above the current pilot
4 customer cap of 2,000. In addition, with this commitment, the Company will remain
5 at the forefront of developing technologies and continue to collaborate with
6 important OEMs within the service territory as EV adoption continues to grow.

7

8 **Q74. How much is the Company forecasting to invest in O&M in the Smart Charge**
9 **Program?**

10 A74. The Company is forecasting to spend \$0.8 million to support the expansion of the
11 Smart Charge Program. The investment in Smart Charge will allow the Company
12 to transition to a program and support increased participant enrollment. The costs
13 are associated with platform fees, marketing and customer participation incentives.

14

15 **Q75. Has the Commission and MPSC Staff been supportive of the Company's**
16 **efforts in pursuing a Smart Charge?**

17 A75. Yes. The MPSC Staff and Commission have supported the Smart Charge pilot in
18 several cases including the 2019 IRP (Cast No. U-20471), 2022 Electric Rate Case
19 (Case No. U-20836), 2023 Electric Rate Case (Case No. U-21297), as well the DR
20 Reconciliation Cases beginning with Case No. U-20521 filed in 2019.

21

22 **Q76. Could you describe the vehicle-to-home (V2H) EV pilot?**

23 A76. The Company is partnering with two leading OEMs to evaluate V2H technology.
24 This pilot, as detailed in Exhibit A-12, B5.6.3, is one of the first in the country and
25 expands the DR team's EV portfolio and collaboration with leading OEMs. The

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1 Company finalized a preliminary agreement in December 2023 and is targeting a
2 completed Statement of Work in the first half of 2024 that will be used as the basis
3 for this pilot. Similar to the WeaveGrid portion of Smart Charge, the funding for
4 the software components and the monthly EV fees of the participating OEMs was
5 made available through the Emerging Technology ETF that was approved in Case
6 No. U-20836³. The O&M requested in this instant case will support the incentives
7 associated with customer enrollment and participation and will be funded by
8 Demand Response. The forecasted incentive spend will be subject to future DR
9 reconciliation while the spend associated with software and monthly fees will not
10 be subject to future DR reconciliations.

11

12 Initially, the pilot is scheduled to run for 12 months after the completion of the
13 SOW. In this pilot, the Company and OEMs will manage the discharge of energy
14 from eligible EVs that are owned or leased by eligible participants. Participants
15 must be DTE Electric residential customers, with a bi-directional charging station
16 already installed at their home to allow the Company to dispatch events and
17 evaluate the feasibility, cost, and customer interest and behavior. Some of the
18 benefits of a V2H type of pilot include:

- 19
- 20 • Providing backup power to a home in the event of an outage or periods of
21 high strain on the electric grid;
 - 22 • Reducing customers' electric bills by signaling the EV to use its battery
23 power during on-peak demand times when electricity from the grid is most
24 costly.

³ As described in Q/A 111 of Burns' Testimony (Case No. U-20836)

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1 **Q77. Can you describe the objectives of the V2H pilot?**

2 A77. Yes. The Company is initially targeting up to 400 eligible participants in its first
3 pilot year to ensure any issues (i.e., communication or signal issues) are resolved
4 prior to the potential expansion to the Company's broader electric customers with
5 eligible EV models. The Company plans to evaluate the success of the pilot as it
6 relates to:

- 7 • Targeting and recruitment efforts needed to enroll in this type of pilot;
- 8 • Determining the appropriate time and length to dispatch events based on the
9 most optimal time to charge and discharge the EV for the participant and the
10 Company;
- 11 • Understanding what incentive structure prompts customer participation;
- 12 • Determining how much demand (kW) and energy (kWh) savings the Company
13 could expect to achieve with the pilot's current participants as well as future
14 potential as additional eligible EV models are available in DTE Electric's
15 service territory;
- 16 • Assessing customer receptiveness and the value to the participants and the
17 Company for this type of V2H pilot;
- 18 • Identifying and processing new learnings that could be applied to current and
19 future DR V2H offerings; and
- 20 • Assess the viability of this resource acting as a year-round DR asset responding
21 on short-term notice for peak events.

22

23 **Q78. Can you describe the residential home generator pilot?**

24 A78. Yes. The Company is conducting a residential customer-owned natural gas
25 generator pilot. The pilot leverages Generac Grid Services' platform and utilizes

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1 telemetry to shift customers' electric load to the customers' generator in real-time
2 during Company called DR events. Customers were prescreened for eligibility to
3 participate in the pilot and were targeted accordingly. One qualifier to participate
4 was, "owner has a premium or dealer managed subscription to Mobile Link." The
5 premium or dealer managed Mobile Link subscription allows the Company to
6 operate a switch-free program capable of remote operations such as responding to
7 demand response events. Through benchmarking with CMS, the Company learned
8 switch programs are more expensive due to the cost of physical LCDs and the
9 associated truck roll for the installation of the LCD. Customers have the options to
10 opt-out of up to two events per calendar year, throughout the duration of the
11 program. Events can occur on any non-holiday weekday between the hours of 8:00
12 am and 8:00 pm within any MISO season, can last no more than four hours and are
13 limited to 40 hours in total each calendar year. The pilot will conclude in December
14 2025. Refer to Exhibit A-12, B5.6.2 for details.

15

16 **Q79. Can you describe the main objectives in pursuing a residential home generator**
17 **pilot?**

18 A79. Yes. The main objectives of the residential generator pilot are as follows:

- 19 • Determine whether customers would be willing to actively participate and
20 allow for real-time telemetry to control their generators during an event;
- 21 • Assess the viability of a pilot that can act as a year-round DR asset
22 responding on short-term notice for peak events;
- 23 • Assess customer receptiveness and the value customers receive from a
24 residential generator pilot; and

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- 1 • Identify and process new learnings that could be applied to current and
2 future demand response offerings.

3

4 **Q80. Is the Commission and MPSC Staff supportive of the Company's efforts in**
5 **pursuing a residential home generator pilot?**

6 A80. Yes. However, when the pilot was first introduced in Case No. U-20836, it was
7 argued by the MPSC Staff that the Commission should disallow the O&M spending
8 associated with the residential generator pilot as there was a concern that the pilot
9 was not well developed. The Commission ultimately agreed with the MPSC Staff.
10 Since that order, the pilot has been further developed. The Company took the
11 recommendation from Staff to benchmark with CMS on their residential generator
12 pilot and leverage their learnings and experience. In the Company's latest general
13 rate case, Case No. U-21297, both MPSC Staff and Commission supported the
14 O&M spend associated with the residential generator pilot, citing the progress the
15 Company has made in the pilot development.

16

17 **Q81. Could you describe the status of the residential home generator pilot?**

18 A81. Yes. In 2023 the Company launched a 200-participant cap residential customer-
19 owned natural gas generator pilot, Demand Response Home Generator Program, in
20 partnership with Generac Grid Services. Recruitment efforts began in July 2023
21 and continued through September 2023, resulting in successful enrollment of 197
22 customers. The Company called its first pilot event on November 28th, 2023.

23

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1 In 2024 the Company is considering a second phase of recruitment to target up to
2 200 additional participants. This second phase of recruitment would provide the
3 opportunity to offer the pilot to a larger subset of different customers.

4

5 **Q82. Are there Other DR Projects that are included in the Pilots and Other Projects**
6 **Category?**

7 A82. Yes. Other DR projects include initiatives that may not necessarily be tied to a
8 specific program or a pilot. The Company plans to set up a dedicated DR call and
9 is exploring partnering with an external party to do so. With a dedicated call center,
10 representatives will be specially trained to inform customers of DR program
11 offerings and benefits and answer customer inquiries on DR programs improving
12 their experience. In addition, the Company is considering partnering with a third-
13 party evaluator to measure the performance of its DR portfolio. This partnership
14 will look at the portfolio holistically and potentially identify improvements to its
15 DR programs. The Pilots and Other Projects category also includes necessary costs
16 to support the competitive DR procurement process that was agreed to in the IRP
17 settlement in Case No. U-21193.

18

19 **Q83. Can you explain the competitive DR procurement that was part of the**
20 **settlement of Case No. U-21193?**

21 A83. Yes. In the settlement of the Company's 2022 IRP, DTE Electric agreed to procure
22 DR-related MISO Zonal Resource Credits (ZRCs) through a competitive bidding
23 process. Specifically, the Company agreed to issue two 25 MW solicitations, one
24 for the 2025/26 Planning Year (PY) and one for the 2026/2027 PY as well as a 100
25 MW solicitation for the 2027/28 PY. The Company plans to spend O&M to contract

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1 with a third-party to assist the Company with developing and supporting the
2 procurement process. The O&M to support this DR procurement effort is expected
3 to be spent in 2024 through 2027.

4

5 **Q84. Can you summarize the Capital and O&M investment amounts for the**
6 **Company's DR Portfolio?**

7 A84. Yes. The Company is forecasting to invest \$17.4 million in capital during the bridge
8 period beginning January 1, 2023, and ending December 31, 2024, and investing
9 \$4.4 million in capital during the forecasted test period ending December 31, 2025.
10 In addition, the Company forecasts O&M spend of \$5.9 million. This overall level
11 of investment will support the Company's current program offerings such as
12 CoolCurrents, Smart Savers, SmartCurrents, and Smart Charge as well as allow the
13 Company to conduct and evaluate pilots to determine if they can become a valuable
14 resource within the portfolio. This spend also supports other DR related projects.

15

16 Forecasted MWs

17 **Q85. What are the forecasted MWs in the DR portfolio as a result of continued**
18 **investment in the programs and pilots?**

19 A85. The Company is forecasting a decrease in the portfolio from 786 MWs in 2022 to
20 712 MWs in the 2025/2026 PY as shown in Table 4. The primary drivers of the
21 projected decrease are the CoolCurrents program and the C&I tariffs. The
22 Company has reduced the MWs associated with the CoolCurrents program to more
23 appropriately reflect the customers who can be successfully interrupted. In addition,
24 the MWs associated with the C&I tariffs was reduced to reflect current customers
25 and their associated operations. This decrease is offset by additional MWs

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associated with the Smart Savers program primarily due to increased participants in the program. The Company also recognizes that as MISO continues to explore short-term and long-term accreditation changes there will likely be impacts to the amount of MWs available in the Company's DR Portfolio. The Company is committed to continued growth of the portfolio and prudent spending to assure the Company and its customers are receiving the maximum benefits of demand response. However, the Company will need to remain flexible and understands that the changing customer preferences and evolving DR landscape can change the MW makeup of the portfolio.

Table 4 Projected 2025/2026 PY MWs (ICAP)

Program	Projected 2025 MWs
Smart Savers	108
SmartCurrents	48
CoolCurrents	130
Legacy Tariffs ⁴	345
Rider 12	56
DR Procurement	25
Total	712

Part V: Evolving DR Landscape

Q86. What changes has MISO implemented or are being proposed?

A86. Beginning with the planning resource auction (PRA) for the 2023/24 PY, MISO changed its resource adequacy construct from an annual to a seasonal format. The premise of the construct, where MISO establishes a planning requirement to serve

⁴ Includes D3.3, D8, R1.1, R1.2 and R10

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1 load during peak times, and this requirement is fulfilled with resources accredited
2 based on performance, remain unchanged. However, with the change to a seasonal
3 construct, MISO has moved from setting a single annual planning requirement and
4 accrediting resources with a yearly value, to establishing a planning requirement
5 and assigning accreditation to resources for each season (spring, summer, fall and
6 winter). Lastly, MISO is exploring various short-term and long-term accreditation
7 and registration changes for LMRs.

8

9 **Q87. Could you describe the seasonal construct that MISO implemented?**

10 A87. Yes. MISO implemented a seasonal construct where capacity is valued differently
11 in each MISO Season and resources are accredited based on the capacity value and
12 performance of that resource in each season. The MISO Seasons are as follows:

- 13 • Summer: June, July, August
- 14 • Fall: September, October, November
- 15 • Winter: December, January, February
- 16 • Spring: March, April, May

17

18 **Q88. Has the Company made any changes to its DR portfolio in response to the**
19 **seasonal capacity construct?**

20 A88. Yes. The Company is focused on pilots that can be available year-round and is
21 evaluating what changes, where appropriate, could be made to programs in its
22 current portfolio to expand their availability to other seasons.

23

24 **Q89. What short-term accreditation and registration changes is MISO exploring?**

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1 A89. On a short-term basis, MISO is exploring accrediting LMRs based on actual historic
2 availability. MISO is also exploring enhancing the auditability of its LMR
3 availability data by asking for more frequent MISO data submittals from market
4 participants. It is important to note that while MISO is considering making these
5 changes, no tariff changes have been made and nothing has been filed with the
6 Federal Energy Regulatory Commission (FERC) as of this filing.

7
8 **Q90. What long-term accreditation and registration changes is MISO exploring?**

9 A90. The long-term change that MISO is exploring is separating LMRs into emergency
10 only and non-emergency categories. MISO is currently indicating that emergency
11 only LMRs would require a 30-minute lead time for notification and non-
12 emergency LMRs would have to participate in the energy market, but this proposal
13 is subject to change as it moves through the MISO stakeholder process. Currently
14 the Company's LMRs do not participate in the energy market. Much like the short-
15 term accreditation and registration changes, no tariff changes have been made and
16 nothing has been filed with FERC to date.

17
18 **Q91. What is the Company doing to prepare for potential MISO changes that may
19 impact its DR portfolio?**

20 A91. The Company will continue to keep abreast of these proposals through stakeholder
21 meetings and will remain flexible when it comes to its DR Portfolio, understanding
22 that these changes, if filed and approved, could change the way the Company
23 manages and designs its DR Portfolio. As these proposals become better understood
24 and possibly implemented, the Company will include in future DR filings any
25 potential impacts to the Company's DR Portfolio. In addition, the Company will

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1 examine the potential to adjust current programs, where possible, to provide
2 capacity for additional seasons beyond summer. The Company will also evaluate
3 the likely LMR accreditation changes and determine if any program adjustments,
4 such as number of events or event timing, would improve the capacity credit of its
5 programs. Continued investment in DR is important to ensure the Company can
6 make quick decisions regarding its programs and pilots and can, where possible,
7 position the Company and its customers the best possible outcome as changes occur
8 as DR resources continue to be valuable resources within MISO's capacity
9 construct.

10

11 **Part VI: DTE Insight Program**

12 **Q92. Can you please describe the DTE Insight program?**

13 A92. Yes. DTE Insight is a comprehensive program that centers on a mobile application
14 (DTE Insight App) integrated with the Advanced Metering Infrastructure (AMI) to
15 help residential customers monitor and manage their energy use. Customers using
16 the DTE Insight mobile application view their prior day's energy usage on an hour-
17 by-hour basis, allowing customers to assess how recent weather and activities can
18 impact their home energy usage. Customers can combine the DTE Insight App with
19 an Energy Bridge (EB) device and obtain real-time energy information and manage
20 connected smart devices.

21

22 **Q93. How has the Company been developing and implementing the DTE Insight**
23 **program since its inception?**

24 A93. The Company has been investing in the DTE Insight program, including the
25 additional offering of EB devices, since 2014. In 2018, the Company enhanced the

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1 program into a more robust platform, including both an updated application and an
2 improved EB device. Starting in 2019, the Company began offering a combination
3 of smart home features to all DTE Insight customers with the EB. With the
4 expanded functionality of the EB device, participating customers can also control
5 other connected smart devices (i.e., thermostats, lightbulbs, switches, plugs, and
6 outlets). These smart devices can report energy consumption to the users and allow
7 the users to set activities-based rules. DTE Insight is a program that aims at driving
8 customer behavior with the goals of reducing both overall energy (gas and
9 electricity) consumption and electricity demand at peak hours.

10

11 **Q94. Has the Commission been supportive of the DTE Insight program?**

12 A94. Yes. The Commission approved expenditures for this program in Case Nos. U-
13 18255, U-20162, U-20561, and U-20836.

14

15 **Q95. Did the Commission approve all capital costs related to the DTE Insight**
16 **program in Case No. U-21297?**

17 A95. No. The Commission disallowed \$1.4 million of 2022, \$0.7 million for 2023 and
18 \$0.6 million for 2024.

19

20 **Q96. What was the Commission's reason for not approving the DTE Insight**
21 **capital?**

22 A96. The Commission agreed with the ALJ and Staff. "The Staff argued that capital
23 expenditures for this program should be fully disallowed based on low engagement
24 and participation in a nine-year-old program that the company began investing in
25 in 2014. In this regard, the Staff averred that DTE Electric should boost engagement

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1 and participation in the application and in the use of EB devices before investing
2 more money into the program.” (U-21297 order, page 141)

3

4 **Q97. Are you seeking recovery of the capital costs in this proceeding?**

5 A97. Yes.

6

7 **Q98. What has changed since the prior case to address the Commission and Staff’s**
8 **concerns with the DTE Insight capital?**

9 A98. Unlike the prior case, the Company is not seeking recovery of capital costs related
10 to additional energy bridges or expansion of the program. Additionally, in the prior
11 case, “the Staff averred that DTE Electric should boost engagement and
12 participation in the application and in the use of EB devices before investing more
13 money into the program.” (U-21297 order, page 141). As reported in Table 5
14 below, in the 12 months between December 31, 2022, to December 31, 2023, the
15 DTE Insight program saw an increase of over 110,000 in authenticated household
16 downloads and over 18,000 authenticated household with energy bridges. The 47%
17 and 48% increase in these metrics shows customers continue to gravitate to the
18 DTE Insight Program. To keep the program available for existing customers, the
19 Company is seeking to recover costs related to app maintenance, software licensing,
20 and customer support.

21

22 **Q99. What are the most updated metrics regarding the development and**
23 **implementation of the DTE Insight program?**

24 A99. The Company has been focusing on increased EB utilization rate and increased
25 customer participation and engagement while it has continued the development and

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1 implementation of the overall DTE Insight program. As shown in Table 5 below,
2 the following metrics reflect the continuous and increasing customer engagement
3 and participation in the program:
4

5 **Table 5 – DTE Insight Metrics**
6

	Cumulative Data as of Dec 31, 2022	Cumulative Data as of Dec 31, 2023
Authenticated Household Downloads	233,384	343,461
Authenticated Household Energy Bridges	38,093	56,519

7

8 **Q100. What are the Company's planned efforts with respect to the DTE Insight**
9 **program?**

10 A100. The DTE Insight program continues to evolve from providing simple usage data to
11 delivering actionable communications and educational content to its users. Not only
12 does the DTE Insight App provide energy data visualization and coaching, but it
13 also provides a comprehensive customer experience hub for energy insights,
14 intelligence, and automations. While the DTE Insight program has been primarily
15 utilized by energy waste reduction (EWR) customers, DTE Insight has the potential
16 to become an effective educational tool for customers in other Company programs
17 such as Advanced Customer Pricing Pilot, MIGreenPower, and Charging Forward.
18 With the increasing interest, the Company expects the number of DTE Insight App
19 users and EB requests to continue to rise.
20

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1 **Q101. How much is the Company forecasting to invest in the DTE Insight program**
2 **during the bridge period of January 2023 through December 2024, and in the**
3 **projected test year ending December 31, 2025?**

4 A101. The Company is forecasting to invest \$1.4 million in capital expenditures during
5 the bridge period of January 1, 2023, through December 31, 2024, and \$1.6 million
6 in capital expenditures for the projected test year from January 1, 2025, through
7 December 31, 2025. The Company is requesting this level of investment as it is
8 necessary to complete the plans described above, which include continued
9 enhancement of the customer experience in the use of the program as an educational
10 tool to support the growing participation from customers in other Company
11 programs mentioned above. Examples of expenditures include ongoing app
12 maintenance, software licensing, and phone and field technical support for
13 customers. The associated projected capital expenditures are shown in Exhibit A-
14 12, Schedule B5.6, page 1 of 2, line 5, column (c) through (f).

15

16 **Q102. Is the DTE Insight program included as part of the Company's DR programs**
17 **and pilots and subject to the three-phase framework?**

18 A102. No. The DTE Insight program is not subject to the evaluation and assessment
19 established by the DR three-phase framework. General rate cases remain the
20 appropriate regulatory proceedings for the Commission to evaluate the Company's
21 proposed execution work and associated capital expenditures for the DTE Insight
22 program. Therefore, the Insight program is not subject to future DR reconciliation.

23

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

25 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

REBUTTAL TESTIMONY

OF

KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF KEEGAN O. FARRELL

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

3 A1. My name is Keegan O. Farrell (he/him/his). My business address is: One Energy
4 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company as the
5 Manager of Demand Response (DR).

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my testimony is to

- 14 • Respond to testimony of Witness Matthews of the Michigan Public Service
15 Commission (MPSC or Commission) Staff (Staff) on the Company's
16 Commercial and Industrial (C&I) Battery Storage DR Pilot and the
17 proposed disallowance;
- 18 • Respond to testimony of Witness Sherman of The Michigan Energy
19 Innovation Business Council, Institute for Energy Innovation and Advanced
20 Energy United (MEIBC) on the Company's C&I Battery Storage DR Pilot;
- 21 • Respond to testimony of The City of Ann Arbor (AA) Witness Stults
22 regarding the Company's residential generator DR Pilot;
- 23 • Address DR recommendations in the testimony of Witness Richter of the
24 Great Lakes Renewable Energy Association (GLREA);

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- 1 • Address DR recommendations in the testimony of Witness Volkmann
- 2 representing The Ecology Center, Environmental Law & Policy Center,
- 3 Union of Concerned Scientists, and Vote Solar (CEO) and;
- 4 • Respond to testimony of Witness Doherty of the MPSC on the Company's
- 5 SmartCurrent expenditures and address DR recommendations.

6

7 The absence of a discussion of other matters in my testimony should not be
8 regarded as an indication that I agree with all other aspects of the Staff's and
9 intervenor's testimony. The narrow focus of my testimony is instead a
10 consequence of a focus on priority issues in recognition of the available resources.

11

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

13 A4. No, I am not.

14

15 **REBUTTAL TO MPSC STAFF WITNESS MATTHEWS**

16 **Q5. Could you summarize the Company's C&I Battery Storage DR pilot?**

17 A5. Yes. The Company's C&I Battery Storage DR pilot is designed to test the ability
18 to achieve peak demand shaving or shifting during DR events. The pilot will consist
19 of two 250 kW/1 MWh behind-the-meter (BTM) lithium-ion phosphate battery
20 energy storage systems (BESS) at two customer sites. One of the two customers
21 has been identified and the Company is actively working with the customer on the
22 installation and implementation parameters for the BESS.

23

24 **Q6. What recommendation did Staff Witness Matthews' make on the Company's**
25 **C&I Battery Storage DR pilot?**

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1 A6. Witness Matthews (p. 7, lines 7-11) recommends that the Company limit the pilot
2 to a single participant, citing the Company's difficulty in finding a second
3 participant. In addition, Witness Matthews correctly states that the Company is not
4 planning to charge a fee to participating customers and therefore recommends
5 charging a fee to the second participant once the Company has determined the value
6 of the program through testing (lines 16-21).

7
8 **Q7. Why does Witness Matthews make these recommendations?**

9 A7. On page 9, lines 14-20, Witness Matthews states that by charging a fee to the
10 customer, the customer would become more accustomed to a fee and inclined to
11 leverage the battery to recoup its cost. Witness Matthews goes on to say that
12 charging a fee will make the customer more likely to retain the battery after the
13 pilot (lines 16-17) as well as stating that Staff finds it critical to test whether
14 payments for participation would impact the customer's utilization of the battery
15 (lines 18-19).

16
17 **Q8. Does Witness Matthews make any other recommendations about the**
18 **Company's C&I Battery Storage DR Pilot?**

19 A8. Yes. Witness Matthews also recommends the Commission disallow \$2 million for
20 the pilot which includes \$1.4 million in the bridge year and \$0.6 million in the
21 forecasted test year.

22
23 **Q9. How do you respond to Witness Matthews' position that the Company should**
24 **only move forward with one participant?**

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1 A9. While Witness Matthews is correct that a second participant has not yet been
2 determined, the Company is working diligently to find one. By having a second
3 customer with a different load profile and operating characteristics participate in
4 the pilot, the Company can increase its learnings such as comparing battery
5 operations, customer savings, ability to respond to a DR event and the ability to
6 shift and/or reduce load. In addition to these learnings, a second customer will help
7 the Company understand different load shapes to support load forecasting as battery
8 adoption grows. The Company continues to have conversations with interested
9 customers and has worked with its Renewables and Major Account Services Teams
10 to identify and engage potential participants. Only proceeding with one participant
11 at this time would be inappropriate and disengaging to the potential participants
12 who have already been approached by the Company and are either looking for
13 funding opportunities or seeking approval from their executive management to
14 participate. In addition, not yet having a second customer to participate in the pilot
15 is not impacting or delaying the launch of the pilot as the lead time for the ancillary
16 equipment is longer than anticipated. The battery skids will be developed
17 sequentially, and the second skid will be shipped following shipment of the first.
18 Installation for both batteries is not expected to be completed until the H2 of 2025.

19

20 **Q10. Do you agree with Witness Matthews that the Company should charge a fee**
21 **for participation?**

22 A10. No, I do not agree. Witness Matthews states in his direct testimony that the
23 Company is having difficulty finding a second participant yet recommends the
24 Company charge the second participant a fee to participate. This would only further
25 hinder the Company from finding a second participant. Participants have to pay an

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1 estimated \$100,000 to \$150,000 in up-front costs that are associated with the
2 concrete pad and the necessary electrical work. A few of the customers the
3 Company spoke to opted to turn down the Company's offer to participate, citing
4 up-front costs as a reason they choose not to participate. In addition, Witness
5 Matthews provides no evidence that participating customers who pay a fee to
6 participate would leverage the battery more efficiently to recoup the costs. If this
7 argument were to be true, the same could be said for the up-front costs that are
8 incurred by the participating customers.

9

10 **Q11. Should the MPSC disallow \$1.4 million in the bridge period and \$0.6 in the**
11 **forecasted test year associated with the C&I Battery Storage DR Pilot?**

12 A11. No. For the reasons previously discussed, the Company continues to make progress
13 in finding a second participant. In addition, the bridge period spend, and the
14 forecasted test year spend is associated with both batteries and are divided into
15 project milestone payments, not necessarily on a per battery basis. The spend in the
16 bridge period is for procurement of major equipment and implementation costs
17 associated with the pilot inclusive of installation, warranty, and maintenance.

18

19 **REBUTTAL TO MEIBC WITNESS SHERMAN**

20 **Q12. Did MEIBC Witness Sherman recommend any disallowances?**

21 A12. Yes. Beginning with line 11 on page 54 of her direct testimony, Witness Sherman
22 recommends the Commission disallow the costs associated with the C&I Battery
23 Storage Pilot due to not having a second customer identified. Witness Sherman
24 goes on to say that the spend could be approved in the next rate case if a second
25 customer is identified by then.

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1 **Q13. How do you respond to Witness Sherman's recommendations?**

2 A13. The Company appreciates the support from Witness Sherman on future rate case
3 recovery for the C&I Battery. However, for the same reasons as discussed above in
4 Question 11, the costs associated with the C&I Battery Storage pilot should be
5 considered prudent and the Company should receive full recovery.

6

7 **REBUTTAL TO AA WITNESS STULTS**

8 **Q14. Could you summarize the Company's residential home generator pilot?**

9 A14. Yes. The Company's has partnered with Generac Grid Services on the pilot to shift
10 customers' electric load to the customers' generator during peak events. The initial
11 phase of the pilot began in 2023 and the Company successfully enrolled 197
12 customers. Phase two of the pilot is scheduled for later this year which will target
13 enrolling an additional 200 participants. The main objective of the pilot is to
14 determine whether customers would be willing to actively participate and allow for
15 real-time telemetry to control their generators during an event. Pilot participants are
16 incentivized with a \$100 up-front gift card and a \$250 gift card at the end of the
17 pilot term if they stay enrolled for the entire duration.

18

19 **Q15. What position does AA Witness Stults take in regard to the Company's**
20 **residential home generator pilot?**

21 A15. Beginning with line 20 on page 3 of her direct testimony, AA Witness Stults
22 recommends that the Commission disallow all costs associated with residential
23 generator pilot.

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1 **Q16. Why does Witness Stults recommend that the Commission disallow the costs**
2 **associated with the residential home generator pilot?**

3 A16. Witness Stults states that the pilot does not align with the Company's stated climate
4 goals. On page 30, line 5, Witness Stults that "a program that explores the ability
5 to remotely shift a customer's electric load to a gas generator as a demand response
6 solution is simply not in line with the Company's stated climate goals or its claims
7 regarding protecting our planet and planning for our future."

8

9 **Q17. Does Witness Stults provide any alternative proposals to the Company's**
10 **proposed residential home generator pilot?**

11 A17. Yes. Beginning with line 9 on page 30, Witness Stults states the Company could
12 explore a similar pilot using batteries as the power source rather than generators.

13

14 **Q18. How does the Company respond to AA Witness Stults?**

15 A18. Witness Stults appears to misunderstand the purpose of the residential home
16 generator pilot.

17

18 The pilot is targeting customers who already own a whole-home generator. The
19 residential home generator DR pilot is not incentivizing customers to purchase and
20 install a natural gas generator. It is simply targeting customers who already own the
21 technology and incentivizing them to let DTE Electric shift their whole-house load
22 to their generator during DR events. The Company's use of these existing
23 generators during emergency situations lowers the amount of new firm capacity the
24 company requires which allows for additional intermittent renewable resources –
25 helping the Company achieve its clean energy goals. This pilot could become the

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1 framework for a residential battery pilot as the Company continues to understand
2 these types of whole-home resources and their value during DR events.

3

4 **Q19. How does the Company respond to AA Witness Stults's alternative proposal**
5 **to explore a similar pilot using batteries?**

6 A19. Witness Stults alternative proposal around exploring residential batteries has merit
7 as the Company continues to learn about the value of these whole home resources.
8 However, the Company is focused on learning as much as it can from the residential
9 generator pilot before turning its attention to another whole-home pilot. The
10 learnings from the residential home generator pilot may help design the framework
11 for a residential battery DR pilot. Therefore, Witness Stults' proposal to disallow
12 the residential pilot and instead focus on a residential battery pilot should be
13 rejected.

14

15 **REBUTTAL TO GLREA WITNESS RICHTER**

16 **Q20. What recommendations does GLREA Witness Richter make in regard to the**
17 **Company's DR programs?**

18 A20. Beginning on page 35 of his direct testimony, GLREA Witness Richter discusses a
19 critical peak (CP) rebate program and the benefits of such a program. Witness
20 Richter also discusses the benefits of a grid interactive water heater (GIWH) DR
21 program beginning on page 46 of his direct testimony. Ultimately, he recommends
22 the Commission direct the Company in its next rate case or demand response case,
23 to propose a CP-rebate pilot program (p. 46, lines 2-5) and a GIWH pilot program
24 (p. 52, lines 1-4).

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1 **Q21. How do you respond to Witness Richter's DR pilot recommendations?**

2 A21. The Company appreciates the testimony of Witness Richter. Witness Richter
3 discusses the benefits of DR and thoroughly explains his proposed CP-rebate pilot
4 program and GIWH pilot program. The Company will keep these suggestions in
5 mind for potential future pilot opportunities.

6

7 **Q22. Does Witness Richter make any further recommendations beyond the CP-
8 rebate pilot program and the GIWH pilot program?**

9 A22. Yes. In addition to recommending the Commission direct the Company to propose
10 these two types of pilot programs, he recommends the Commission create the
11 opportunity for a third-party aggregator to do so if the Company resists.

12

13 **Q23. What are your thoughts on the recommendation for the Commission to create
14 an opportunity for third-party aggregators to conduct pilots?**

15 A23. The Company disagrees with the recommendation that the Commission create an
16 opportunity for third-party aggregators to conduct the pilots. In Case No. U-21099,
17 the Commission partially lifted the ban on DR aggregation for bundled electric
18 customers, enacting a size minimum of 1 MW of enrolled load and keeping the ban
19 in place for residential customers. Allowing third-parties to conduct a residential
20 pilot, which would include a CP-rebate pilot and GIWH pilot would be a violation
21 of the U-21099 Order. Furthermore, in the U-21099 Order, the Commission
22 indicated its intention to work with stakeholders to develop appropriate consumer
23 protection policies for resources smaller than 1 MW. Therefore, Witness Richter's
24 recommendation of allowing a third-party to conduct a CP-rebate pilot and GIWH
25 pilot should be rejected.

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1 **REBUTTAL TO CEO WITNESS VOLKMANN**

2 **Q24. How does Witness Volkmann describe a virtual power plant (VPP)?**

3 A24. Beginning on line 1 of page 21 of his direct testimony, Witness Volkmann describes
4 a VPP as “aggregations of customer-owned DER (distributed energy resources)
5 such as rooftop solar and behind-the-meter (“BTM”) batteries, electric vehicles and
6 chargers, electric water heaters, smart buildings and their controls, and flexible
7 commercial and industrial loads that can balance electricity demand and supply and
8 provide utility-scale and localized grid services.”
9

10 **Q25. What is Witness Volkmann’s recommendation regarding VPPs?**

11 A25. On page 25, Witness Volkmann recommends that the Company work with Staff
12 and stakeholders to design a VPP pilot/demonstration for resilience and peak load
13 reduction use-cases using a third-party aggregator, and to include the
14 pilot/demonstration in its 2025 DGP.
15

16 **Q26. How does the Company respond to Witness Volkmann’s recommendation?**

17 A26. The Company appreciates Witness Volkmann’s recommendation and his
18 discussion on VPPs. As noted above, DR aggregation at the residential level is
19 currently banned in the state of Michigan. Currently, the Company offers an array
20 of DR offerings that include such pilots and programs as the residential home
21 generator pilot, Smart Charge pilot, Smart Savers (bring-your-own-thermostat or
22 BYOT), and SmartCurrents among others. The Company works with implementers
23 such as EnergyHub and Weavegrid and looks to further expand these relationships
24 with additional product offerings while also bringing any current and future
25 offerings into a single portfolio. In addition, the Company recently held a

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1 competitive request for proposal to procure 25 MWs of third-party DR as agreed
2 upon in the Company's most recent IRP, Case No. U-21193.

3

4 **REBUTTAL TO MPSC STAFF WITNESS DOHERTY**

5 **Q27. Could you provide background on the Company's SmartCurrents \$1.7 million**
6 **disallowance in 2021?**

7 A27. Yes. As described on page 24, lines 8-14 of my direct testimony, it was agreed upon
8 in the settlement of Case U-21252 (2021 DR Reconciliation) to disallow
9 \$1,672,895 in capital expenses associated with the SmartCurrents Program. The
10 MPSC Staff recommended the disallowance citing that the program was only
11 preapproved for \$3 million in 2021 through Case No. U-20471 (the Company's
12 2019 Integrated Resource Plan (IRP)). The disallowance was the difference
13 between the actual spend on SmartCurrents in 2021 and the approved \$3.3 million
14 (\$3 million plus 10%). In Case U-21242, Staff did not find the overspend to be
15 reasonable because of the lack of value of these costs as demonstrated by the Utility
16 Cost Test (UCT).

17

18 **Q28. What is Witness Doherty's position on the 2021 disallowance in the instant**
19 **case?**

20 A28. Beginning with line 20 on page of his direct testimony, Witness Doherty states that
21 the Staff's recommendation with respect to the disallowed SmartCurrents costs has
22 not changed as the Staff recommended the disallowance due to the spend exceeding
23 what was preapproved in the Company's 2019 IRP. He also states that the Company
24 failed to communicate with Staff that it was exceeding its investment in

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1 SmartCurrents by more than 10% and that the benefits from the increased
2 investment did not exist or unclear.

3

4 **Q29. How does the Company respond to Witness Doherty's recommendation that**
5 **2021 disallowance should remain?**

6 A29. While the Company acknowledges that it overspent what was preapproved in the
7 2019 IRP, the Company requests that \$914,448 be added to the projected test year
8 rate base as the overspend in SmartCurrents was reasonable and prudent. As stated
9 on page 24 of my direct testimony, the overspend was to create a new webpage for
10 the program that enhanced and streamlined the potential and existing customer
11 journey. The new webpage included the additions of allowing for self-service
12 enrollment, unenrollment and management of communication preferences.

13

14 In addition, as further described on page 25 of my direct testimony, a result of the
15 new webpage, the Company has been able to increase enrollments and improve
16 efficiencies in the enrollment process. After the spend increase in 2021, the
17 SmartCurrents program has been cost-effective on a forward looking Levelized
18 Cost of Capacity (LCOC) in 2022 and 2023. This supports the investment the
19 Company made in 2021 to enhance the SmartCurrents program and the
20 expenditures added immense customer value to the program. The \$914,448 of
21 disallowed capital should be considered reasonable and prudent and therefore
22 recoverable.

23

24 **Q30. Did Witness Doherty make any recommendations for the Company's DR**
25 **portfolio?**

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1 A30. Yes. Beginning with line 18 on page 6 of his direct testimony, Witness Doherty
2 recommends expanding the Company's analysis of the cost-effectiveness of its DR
3 programs to include all DR programs as well as interruptible rates. He further
4 recommends that the analysis should be included in its next DR Reconciliation or
5 General Rate Case, whichever happens sooner.

6

7 **Q31. How does the Company respond to Witness Doherty's recommendation?**

8 A31. The Company supports and agrees to expand its cost effectiveness test to include
9 all DR programs, including its DR tariffs. However, the Company believes that any
10 discussion of cost-effectiveness should remain within DR Reconciliation cases only
11 and not be included in rate cases. As the Company issues the results of its cost-
12 effectiveness tests in its annual DR reconciliations today, there is no reason to pull
13 them out of a dedicated DR case and into a much larger and more complex electric
14 rate case filing.

15

16 **Q32. Does this conclude your rebuttal testimony?**

17 A32. Yes, it does.

1 JUDGE WALLACE: All right. Please go
2 ahead.

3 MS. REITZEL: Thank you, your Honor.
4 DTE Electric also previously filed and now moves in,
5 moves to bind into the record the Direct Testimony of
6 Robert J. Lee. His direct testimony consisted of a cover
7 sheet and 23 pages of questions and answers. Witness Lee
8 had no rebuttal and no rebuttal exhibits.

9 JUDGE WALLACE: Did he have any direct
10 exhibits?

11 MS. REITZEL: No, ma'am.

12 JUDGE WALLACE: Oh, O.K. Is there any
13 objection to binding in the direct testimony of Mr. Lee?

14 Hearing none, the testimony is bound in.
15 (Testimony bound in.)

16 - - -

17

18

19

20

21

22

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25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
ROBERT J. LEE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT J. LEE

Line
No.

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

2 A1. My name is Robert J. Lee (he/him/his) and my business address is One Energy
3 Plaza, Detroit, Michigan 48226-1279. I am employed by DTE Energy Corporate
4 Services, LLC within DTE's Environmental Management and Safety team and I
5 am currently the Manager of Environmental Strategy for the Company.

6

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

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

9

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

11 A3. I received a Bachelor of Science Degree in Geology in 1992 and a Master of
12 Science Degree in Environmental Geochemistry in 1994 from the University of
13 Wales.

14

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

16 A4. Since completing my formal education, I have practiced continuously in the
17 environmental field with a focus on State and Federal programs mostly in
18 Michigan. My past and current responsibilities include management of several
19 environmental program areas, including Effluent Limitations Guidelines (ELG)
20 and water permit management, Coal Combustion Residual (CCR) program
21 management, remediation program management, State and Federal construction
22 permit programs, and coal plant retirement. Additionally, I have State and Federal
23 level experience supporting and developing legislative and rule-making initiatives.

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1 From 1994 to 2004, I worked in environmental consulting and environmental
2 engineering. I managed a wide variety of projects for various industries focusing
3 on remediation project management, solid waste compliance, coal ash
4 management, National Pollutant Discharge Elimination System (NPDES) permit
5 management and obtaining and managing State and Federal permits. I also
6 performed complex multi-site due diligence and liability management. I worked
7 for a variety of industries including utility, cement production, and landfill industry
8 sectors.

9

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

11 A5. I have worked for DTE Energy for 19 years. I am currently the Manager of
12 Environmental Strategy, and my focus is on complex and strategic environmental
13 initiatives that are critical to DTE. In this role I focus on environmental strategy,
14 policy, and regulatory development and am responsible for key environmental
15 programs at the State and Federal level that are critical to the Company's
16 compliance, strategic direction, and generation strategy. I am responsible for the
17 Company's strategy and approach for compliance with the CCR and ELG
18 programs, coal plant retirement, asset reuse, waste program, and renewable energy
19 development.

20

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

23 A6. Yes. I have sponsored testimony in the following cases:

24 U-16999 2012 DTE Gas General Rate Case

25 U-17999 2015 DTE Gas General Rate Case

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1	U-20642	2019 DTE Gas General Rate Case
2	U-20940	2021 DTE Gas General Rate Case
3	U-20836	2022 DTE Electric General Rate Case
4	U-21297	2023 DTE Electric General Rate Case

Line
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1 **Purpose of Testimony**

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

3 A7. I will describe the status of two significant Environmental Protection Agency
4 (EPA) regulations, the Steam Electric Effluent Limitation Guidelines (ELG) Rule
5 and the Coal Combustion Residuals (CCR) Rule, which impact the Company's
6 coal-fired power plants. I will address the following additional topics in my
7 testimony:

8 1) I will explain the ELG Rule, recent revisions, and compliance strategies in
9 support of Witness Guillaumin's discussion of ELG-related capital
10 expenditures.

11 2) I will describe how the EPA's CCR Rule affects the Company's coal-fired units
12 in support of Witness Guillaumin's discussion of CCR-related capital
13 expenditures.

14

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

16 A8. No.

17

18 **Q9. Is the Company requesting recovery of capital expenditures associated with**
19 **compliance with EPA regulations?**

20 A9. Yes. As shown in Company Witness Guillaumin's Exhibit A-12, Schedule B5.1,
21 the Company is in the process of developing and implementing several ELG and
22 CCR compliance projects necessitating capital expenditures, including:

- 23 • Monroe Dry Fly Ash Conversion (ELG)
- 24 • Monroe Bottom Ash Conversion (ELG)
- 25 • Monroe FGD Wastewater (ELG)

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- 1 • Sibley Quarry Landfill Modification (CCR)
- 2 • Sibley Quarry Conveyor Installation (CCR)
- 3 • Sibley Quarry Infrastructure Modification (CCR)
- 4 • Sibley Quarry Landfill Dewatering and Discharging Line (CCR)
- 5 • Monroe Bottom Ash Basin Closure (CCR)
- 6 • St. Clair Bottom Ash Basin Closure (CCR)
- 7 • Belle River Bottom Ash Basin Modification (CCR)
- 8 • Monroe Fly Ash Basin Closure (CCR)

9

10 **Effluent Limit Guidelines**

11 **Q10. What are the Effluent Limit Guidelines (ELGs)?**

12 A10. Effluent Limit Guidelines are national wastewater discharge standards that are
13 developed by the EPA on an industry-by-industry basis. These are technology-
14 based regulations and are intended to represent the greatest pollutant reductions that
15 are economically achievable for an industry. EPA promulgated the Steam Electric
16 Power Generating ELGs in 1974, and amended the regulations in 1977, 1978, 1980,
17 1982, 2015 and 2020. The regulations cover wastewater discharges from steam
18 electric power plants operated by utilities. The Steam Electric ELGs are
19 incorporated into NPDES permits issued by the Michigan Department of
20 Environment, Great Lakes & Energy (EGLE).

21

22 **Q11. Can you describe the recent revisions to EPA's Steam Electric Power**
23 **Generating (SEPG) ELGs?**

24 A11. Yes. The EPA's SEPG ELGs regulate how electric utilities must manage certain
25 wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration

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1 Rule which revised some requirements from the 2015 version of the ELG rule. The
2 Reconsideration Rule revised requirements for two specific waste streams
3 produced by steam electric power plants: flue gas desulfurization (FGD)
4 wastewater and bottom ash transport water (BATW). The Reconsideration Rule
5 provides additional compliance opportunities by finalizing subcategories, such as
6 for the cessation of coal burning activities. Therefore, steam electric plants can
7 comply with ELG requirements for FGD and BATW by either meeting
8 requirements to discharge or meeting requirements of a subcategory.

9

10 **Q12. When must DTE Electric comply with revised ELGs?**

11 A12. The Reconsideration Rule provides opportunities for DTE Electric to evaluate
12 existing ELG compliance strategies and make any necessary adjustments to ensure
13 full compliance with the ELGs in a more cost-effective manner than prior ELG
14 rules. The EPA set the applicability dates for BATW and FGD wastewater retrofits
15 to be "as soon as possible" beginning October 13, 2021, and no later than December
16 31, 2025. For facilities pursuing the FGD wastewater Voluntary Incentives
17 Program (VIP), detailed further below, compliance shall be achieved no later than
18 December 31, 2028. Compliance schedules for individual facilities and individual
19 waste streams are determined through issuance of new NPDES permits by EGLE.
20 For Monroe Power Plant, the NPDES permit contains compliance deadlines of
21 December 31, 2023, for fly ash transport water, December 31, 2025, for BATW
22 and December 31, 2028, for FGD. For Belle River Power Plant, the NPDES permit
23 contains a compliance deadline of December 31, 2028, for BATW.

24

25 **Q13. What are DTE Electric's options for ELG compliance?**

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1 A13. The Company has two options to achieve compliance under the Reconsideration
2 Rule for BATW and FGD wastewater. The first option is to design and engineer
3 new technologies that are compliant with the ELG requirements for BATW and
4 FGD wastewater. The second option is to pursue a compliance subcategory for
5 BATW and FGD wastewater that EPA established within the Reconsideration
6 Rule.

7

8 **Q14. What are the compliance subcategories established within the Reconsideration**
9 **Rule?**

10 A14. One compliance subcategory allows companies to attain compliance with the ELGs
11 for both BATW and FGD wastewater by ceasing coal burning activities, which
12 includes retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies
13 certify that unit(s) would retire the use of coal (or refuel), they can continue to
14 operate those units until the unit's specified coal retirement date, which is required
15 to be before December 31, 2028. For the electrical generating unit(s) that certify
16 under this subcategory, companies need to maintain the existing standard limits
17 already in effect for BATW and FGD wastewater discharges until the day of unit
18 shut down.

19

20 In addition to the cessation of coal burning activities subcategory, the
21 Reconsideration Rule also provides a second compliance subcategory specific to
22 FGD wastewater. The Reconsideration Rule established Best Available
23 Technology (BAT) standard discharge limits for FGD wastewater discharges, and
24 further, finalized a subcategory called the Voluntary Incentive Program (VIP).
25 Under the VIP, companies could choose to meet more stringent effluent limits

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1 established by EPA based on the model technology of membrane filtration or zero-
2 liquid discharge. If a company chooses the VIP option, then the applicability date
3 for FGD wastewater compliance will be December 31, 2028.

4

5 **Q15. How does a company pursue compliance under a compliance subcategory**
6 **from the ELG Rule?**

7 A15. To establish compliance for either of these subcategories, companies were required
8 to submit a Notice of Planned Participation (NOPP) to EGLE. Once submitted,
9 companies are required to submit annual progress reports to EGLE to ensure the
10 commitment of compliance under the subcategories.

11

12 **Q16. When is a company required to submit a NOPP to enter a compliance**
13 **subcategory?**

14 A16. EPA has permitted two separate opportunities by which companies could submit
15 NOPPs to pursue and comply with compliance subcategories. The first opportunity
16 was from October 21, 2020, to October 21, 2021. The second opportunity was from
17 May 30, 2023, to June 27, 2023.

18

19 **Q17. Did the Company submit an NOPP filing for ELG compliance subcategories?**

20 A17. Yes, three NOPPs have been submitted. A cessation of coal NOPP was submitted
21 for Belle River Power Plant on October 13, 2021. A VIP NOPP was submitted for
22 Monroe Power Plant on October 13, 2021. Lastly, a cessation of coal NOPP was
23 submitted for Units 3 and 4 at Monroe Power Plant on April 27, 2023.

24

25 **Q18. Can you describe the Cessation of Coal NOPP filing?**

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1 A18. Yes. To establish compliance for the cessation of coal compliance subcategory
2 detailed above, companies were required to submit an NOPP to the state permitting
3 agency (EGLE). The cessation of coal NOPP included:
4 (1) identification of the electric generating unit (EGU) intended to achieve
5 permanent cessation of coal combustion,
6 (2) expected date that each EGU is projected to achieve permanent cessation of coal
7 combustion,
8 (3) whether each date represents a retirement or a fuel conversion,
9 (4) whether each retirement or fuel conversion has been approved by a regulatory
10 body, and
11 (5) identification of the relevant regulatory body.

12

13 In addition, the NOPP must include a copy of the most recent Integrated Resource
14 Plan (IRP) for which the applicable state agency approved the retirement or
15 repowering of the unit subject to the ELGs, certification of EGU cessation under
16 the CCR rule, or other documentation supporting that the EGU will permanently
17 cease the combustion of coal by December 31, 2028. The NOPP must include, for
18 each such EGU, a timeline to achieve the permanent cessation of coal combustion.
19 Each timeline must include interim milestones and the projected dates of
20 completion.

21

22 At the time the cessation of coal NOPP was submitted for Belle River Power Plant,
23 preliminary modeling and strategy development related to the Company's long
24 term generation plan and IRP was ongoing. Due to those early efforts, the decision
25 to submit the NOPP for Belle River Power Plant was made to preserve some options

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1 being evaluated in the strategy development. In November 2022, the Company
2 submitted its IRP, Case No. U-21193, which included a proposed refueling of Belle
3 River Power Plant units from coal to natural gas combustion. In July 2023, a final
4 Order was issued that approved the refueling of Belle River Power Plant. The
5 Company's NOPP that was submitted for Belle River Power Plant is reflective of
6 the outcome of the IRP.

7
8 After the initial Reconsideration Rule NOPP filing date of October 13, 2021, had
9 passed, EPA learned in meetings with trade associations and utilities that additional
10 facilities wished to avail themselves of the compliance pathway for EGUs seeking
11 to retire or convert to a non-coal fuel source by December 31, 2028, but were unable
12 to make that commitment by October 13, 2021. Therefore, in March of 2023, EPA
13 published a direct final rule to extend the deadline for plants to opt-in to the
14 cessation of coal compliance subcategory promulgated in the Reconsideration Rule.
15 Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193,
16 the Company submitted a cessation of coal compliance subcategory NOPP for
17 Monroe Power Plant Units 3 and 4 during the extension of the deadline established
18 in EPA's direct final rule.

19
20 **Q19. Can you describe the Voluntary Incentive Program (VIP) NOPP filing?**

21 A19. Yes. To establish compliance for the VIP compliance subcategory detailed above,
22 companies were required to submit a VIP NOPP to the state permitting agency
23 (EGLE). The VIP NOPP for FGD wastewater included:
24 (1) Identification of the facility opting to comply with the VIP discharge
25 requirements,

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1 (2) Specification of technology or technologies that are projected to be used to
2 comply with those requirements, and

3 (3) Detailed engineering dependency chart and accompanying narrative
4 demonstrating when and how the system(s) and any accompanying disposal
5 requirements will be achieved by December 31, 2028.

6

7 Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193,
8 the Company submitted a cessation of coal compliance subcategory NOPP for
9 Monroe Power Plant Units 3 and 4 during the extension of the deadline established
10 in EPA's direct final rule. The VIP NOPP submitted on October 13, 2021, still
11 applies for Monroe Power Plant Units 1 and 2, as those units will continue
12 operations until 2032.

13

14 **Q20. Why did DTE Electric submit the VIP NOPP for FGD ELG compliance?**

15 A20. For FGD compliance the Company evaluated a suite of technology options that
16 would achieve both BAT and VIP compliance requirements for ELG FGD
17 compliance. At the time of NOPP development, the Company was still evaluating
18 the suite of potential compliant technologies. To ensure the Company could
19 continue to evaluate all available technologies, including those that achieved VIP
20 compliance, the decision was made to submit the VIP NOPP. By submitting the
21 VIP NOPP, it allowed the Company to continue evaluating all technologies
22 available on the market and not just technologies capable of achieving BAT.

23

24 In 2022, the Company identified an FGD compliance technology that met the VIP
25 compliance requirements and committed the Company to the VIP NOPP.

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1 Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193,
2 Monroe Units 1 and 2 will continue to operate until 2032, and FGD compliance
3 will be achieved by December 31, 2028, for those two units by achieving zero liquid
4 discharge. As detailed above, Monroe Units 3 and 4 will achieve compliance via
5 cessation of coal as indicated by the Company's April 27, 2023, NOPP submittal.

6

7 **Q21. What is DTE Electric's compliance strategy for Belle River Power Plant?**

8 A21. At Belle River Power Plant, fly ash is collected dry and therefore there is no Fly
9 Ash Transport Water (FATW). Additionally, the power plant was constructed and
10 operates without FGDs. Therefore, there is no FGD wastewater. However, the
11 bottom ash is collected using transport water and the ELG Reconsideration Rule
12 requires the Company to achieve compliance with BATW discharge requirements.
13 DTE Electric submitted the NOPP on October 13, 2021, for cessation of coal at
14 Belle River Power Plant. Please see Company Witness Guillaumin's testimony
15 regarding the Company's commitment to convert from coal-fired to natural gas-
16 fired operations by 2026.

17

18 **Q22. What is DTE Electric's compliance strategy for Monroe Power Plant?**

19 A22. At the Monroe Power Plant, the Company completed projects for FATW ELG
20 compliance according to the 2015 ELG Rule and ceased water discharges related
21 to the transport of fly ash. For BATW wastewater ELG compliance, the Company
22 must achieve compliance by the end of 2025 and will terminate the use of water for
23 bottom ash transport at Monroe Unit 1 and 2. For Units 3 and 4 at Monroe, the
24 Company submitted a cessation of coal compliance subcategory NOPP on April
25 27, 2023. For FGD wastewater ELG compliance, the Company is pursuing

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1 compliance using VIP technology for Units 1 and 2 and cessation of coal NOPP for
2 Units 3 and 4. The Company will install a VIP compliant system for Monroe Units
3 1 and 2 no later than the end of 2028. Monroe Units 3 and 4 will retire in 2028
4 according to the Company's 2022 IRP, therefore a cessation of coal NOPP was
5 submitted providing compliance with the FGD wastewater-portion of the ELG Rule
6 as retirement will eliminate FGD wastewater from these units. Please see Company
7 Witness Guillaumin's testimony for further details regarding ELG compliance.

8

9 **Q23. Is the EPA currently revising the 2020 ELG Reconsideration Rule?**

10 A23. Yes. EPA has initiated a supplemental rulemaking to address discharge limits in
11 the Steam Electric Power Generating category. EPA conducted a science-based
12 review of the 2020 Steam Electric Reconsideration Rule under Executive Order
13 13990, finding that opportunities for improvement exist. Additionally, on January
14 3, 2023, the Unified Agenda of Regulatory and Deregulatory Actions (Regulatory
15 Agenda) published by the United States Office of Management and Budget was
16 updated and included a new action conducted by EPA related to ELGs. The Agenda
17 stated the EPA, "...is taking direct final action to extend the date for existing coal-
18 fired power plants to submit a notice of planned participation (NOPP) for the
19 permanent cessation of coal combustion subcategory..... from October 13, 2021,
20 to 90 days after publication of this rule in the Federal Register."¹ On March 29,
21 2023, EPA published the referenced direct final rule and it became effective on
22 May 30, 2023.

23

¹ <https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202210&RIN=2040-AG28>, accessed December 21, 2023

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1 Also, on March 29, 2023, EPA published their proposed ELG rule titled
2 “Supplemental Effluent Limitations Guidelines and Standards for the Steam
3 Electric Power Generating Point Source Category”. The public comment period for
4 the proposed rule closed on May 30, 2023. According to the Regulatory Agenda,
5 EPA plans to release their final supplemental ELG Rule by April of 2024.

6

7 **Q24. Why is the Company requesting recovery of capital expenditures for projects**
8 **associated with the 2020 ELG Reconsideration Rule when it is currently under**
9 **revision?**

10 A24. On August 3, 2021, the EPA issued a Federal Register notice² in which they
11 announced their supplemental rulemaking to revise the 2020 ELG Reconsideration
12 Rule as a result of their review conducted under Executive Order 13390. The Notice
13 from EPA states, “While the Agency undertakes this new rulemaking, facilities will
14 continue to be subject to the requirements of the 2015 Rule, as amended by the
15 2020 Rule, which are currently effective.” The Notice goes on to also state, “EPA
16 expects permitting authorities to continue to implement the current regulations
17 while the Agency undertakes a new rulemaking.” Based on these statements made
18 in the August 3, 2021, Federal Register notice by EPA, the Company was required
19 to move forward with the ELG compliance strategy and continue to implement the
20 ELG projects referenced in Q&A9 above. In addition to the Notice, other factors
21 specific to the project such as long lead equipment, construction seasons, and
22 utilizing periodic outages have also driven the need to move forward with ELG
23 compliance projects.

24

² <https://www.federalregister.gov/documents/2021/08/03/2021-16354/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source>, accessed January 19, 2023

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1 **Q25. Other than above, is there other documentation stating that the Company**
2 **must continue implementing ELG compliance projects based on the 2020**
3 **Reconsideration Rule even though EPA is revising it?**

4 A25. Yes, EPA's media release³ from July 26, 2021, in which they announce their 2021
5 supplemental rulemaking to revise the 2020 Reconsideration Rule states, "While
6 the agency pursues the new rulemaking process to strengthen water pollution
7 requirements for coal power plants, the current regulations will be implemented and
8 enforced."
9

10 **Q26. Can the Company avoid capital expenditure for bottom ash compliance on the**
11 **two units proposed to retire in 2028 at Monroe?**

12 A26. Yes. Compliance for bottom ash ELG requirements must be met no later than
13 December 31, 2025. However, as detailed above (Q&A23), the EPA finalized the
14 direct final rule on May 30, 2023, that reopened and extended the timeframe that
15 NOPPs for the cessation of coal compliance subcategory could be submitted. The
16 Company utilized the opportunity presented in the direct final rule and submitted a
17 cessation of coal NOPP for Monroe Units 3 and 4, which are committed to retire in
18 2028. Consistent with the Order in the Company's 2022 IRP filing, Case No. U-
19 21193, Monroe Power Plant Units 1 and 2 will continue to operate until 2032 and
20 so a bottom ash compliance project will still be implemented for ELG compliance.
21

22 **Q27. If the EPA's supplemental ELG Rule update becomes final as proposed, would**
23 **it affect or alter planned capital projects to comply with the current ELG rule?**

³ <https://www.epa.gov/newsreleases/epa-announces-intent-bolster-limits-water-pollution-power-plants>,
accessed March 21, 2024

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1 A27. No. The capital projects for BATW and FGD compliance on Monroe Units 1 and
2 2 both rely on technologies that will ultimately result in no discharge of BATW or
3 FGD wastewater. Zero liquid discharge technologies will always be compliant with
4 ELG requirements as there is no discharge to regulate.

5

6 **Coal Combustion Residuals**

7 **Q28. Can you describe the EPA's Coal Combustion Residuals (CCR) Rule and its**
8 **impact on the Company's coal-fired units?**

9 A28. Yes. The EPA's CCR Rule regulates how electric utilities must manage and dispose
10 of coal combustion residuals in landfills and impoundments. On August 28, 2020,
11 the EPA published an amendment to the CCR rule (the Part A Rule) that requires
12 all unlined surface impoundments to cease receipt of waste and initiate closure as
13 soon as technically feasible but by no later than April 11, 2021. The August 28,
14 2020, amendment also provided utilities the ability to request site-specific
15 alternative closure deadlines through a demonstration process requiring EPA
16 approval. On November 12, 2020, EPA published an additional amendment to the
17 CCR rule (the Part B Rule) that allows utilities the opportunity to demonstrate that
18 their unlined surface impoundments have an alternate liner system that is as
19 protective as a CCR rule compliant liner system. The demonstration processes
20 included in the Part A Rule and Part B Rule require EPA approval to continue
21 operating CCR surface impoundments.

22

23 **Q29. Can you describe the Company's strategy for each CCR unit to comply with**
24 **the "Part A" amended closure provisions of the CCR Rule?**

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1 A29. Yes. The Company submitted a Part A Rule demonstration for the St. Clair Bottom
2 Ash Basins on November 25, 2020, in accordance with 40 C.F.R. §257.103(f)(2).
3 The demonstration requested an alternative closure deadline based on cessation of
4 coal fired generation in spring of 2022, and a commitment to complete closure of
5 the unit by October 17, 2023. Submission of the Part A Rule demonstration paused
6 the April 11, 2021, deadline for the unit to cease receipt of waste. On January 11,
7 2022, the Company received written notice that the Part A Rule demonstration was
8 administratively complete and confirmed that the cease receipt of waste deadline
9 had been paused until EPA issues a final decision on the demonstration. The
10 Company ceased operation of the coal-fired boilers at St. Clair Power Plant on May
11 31, 2022, completed washdowns of CCR containing equipment on August 12,
12 2022, and commenced physical isolation of the St. Clair Bottom Ash Basins from
13 power plant infrastructure on September 1, 2022. These actions demonstrate that
14 the Company has permanently ceased receipt of CCR and non-CCR waste streams
15 at the St. Clair Bottom Ash Basins and has initiated closure by removal pursuant to
16 40 C.F.R. §257.102(c). The Company has therefore withdrawn the Part A
17 demonstration, as it has already ceased receipt of waste. The Company
18 subsequently completed dewatering and CCR removal activities in February 2023.
19 The St. Clair Bottom Ash Basins were backfilled concurrent with and following
20 CCR removal, and topsoil, seed and mulch placement were complete by May 2023.
21
22 On September 13, 2023, EPA acknowledged withdrawal of the Part A
23 demonstration, stating that “EPA reviewed the Demonstration and determined that
24 it included the required information, analyses and documentation specified under
25 40 C.F.R § 257.103(f)(2), and consequently determined on January 11, 2022, that

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1 the Demonstration was complete. The deadline to cease receipt of waste at the
2 Bottom Ash Basins, the CCR units covered by the Demonstration, was paused
3 between April 11, 2021, and September 1, 2022, when the unit ceased receipt of
4 waste. See, 40 C.F.R. § 257.103(f)(3)(ii). Accordingly, EPA updated the Part A
5 webpage ⁴ to reflect that the Bottom Ash Basins no longer receive waste and that
6 DTE has withdrawn its Demonstration.”

7

8 Following closure by removal activities, two rounds of samples were collected from
9 the St. Clair Bottom Ash Basins groundwater monitoring well network.
10 Groundwater constituent concentrations fall below groundwater protection
11 standards as documented in the Company’s Annual Groundwater Monitoring and
12 Corrective Action Report (January 2024). Therefore, the Company completed a
13 notification of closure in accordance with C.F.R. § 257.102(h).

14

15 **Q30. Can you describe the Company’s strategy for each CCR unit to comply with**
16 **the “Part B” alternate liner provisions of the CCR Rule?**

17 A30. Yes. The Company submitted Part B applications to EPA on November 30, 2020,
18 to perform Alternate Liner Demonstrations for Belle River Bottom Ash Basins,
19 Belle River Diversion Basin, and Monroe Fly Ash Basin. The Company received
20 notice of EPA’s proposed denial on January 25, 2023. The Company is continuing
21 with projects at each facility to comply with the CCR rules and support operating
22 the plants. The proposed denials affect each facility as follows:

23

⁴ Coal Combustion Residuals (CCR) Part A Implementation | US EPA available at <https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation>

Line
No.

1 Belle River Bottom Ash Basins and Diversion Basin:

2 As discussed in Witness Guillaumin's testimony, the Company has executed a
3 project to retrofit the Bottom Ash Basins with a CCR-compliant liner system and
4 close the Diversion Basin by removal. The project was completed in 2023 in
5 accordance with regulatory timelines. On September 21, 2023, the Company
6 withdrew the Part B application, as it had already ceased receipt of waste in any
7 unlined portion of the units.

8
9 On October 30, 2023, EPA acknowledged withdrawal of the Part B application,
10 stating that "EPA reviewed the application and determined that it included the
11 required information, analyses and documentation specified under 40 C.F.R. §
12 257.71(d)(1), and consequently determined on January 11, 2022, that the
13 application for the Bottom Ash Basins and the Diversion Basin was complete. On
14 January 25, 2023, EPA issued a proposed decision to deny the application for both
15 the Bottom Ash Basins and the Diversion Basin. In accordance with 40 C.F.R. §
16 257.71(d)(1)(iii)(A), the deadline to cease receipt of waste for the Bottom Ash
17 Basins and the Diversion Basin was tolled the entire period between April 11, 2021,
18 and July 6, 2023, and May 16, 2023, respectively, when the units ceased receipt of
19 waste."

20
21 Following closure by removal activities for the Diversion Basin, two rounds of
22 samples will be collected from the groundwater monitoring well network to certify
23 that closure by removal is complete. Final notification of closure completion is
24 expected in 2024.

25

Line
No.

1 Monroe Fly Ash Basin:

2 The Company was already in process of developing alternative capacity at Monroe
3 by converting the existing wet fly ash handling system to a dry system in
4 accordance with the 2015 ELG rule. The dry fly ash conversion is complete, and
5 the Fly Ash Basin received its last known shipment of waste on December 29, 2023,
6 and as discussed in the Notification of Intent to Close, the Company has initiated
7 closure within the appropriate regulatory timeframes. Therefore, on January 25,
8 2024, the Company withdrew the Monroe Fly Ash Basin Part B Application.

9

10 **Q31. Can you describe the Company's strategy for closure of Monroe Bottom Ash**
11 **Basin?**

12 A31. Yes. The Company ceased receipt of CCR at the Monroe Bottom Ash Basin prior
13 to the effective date of the 2015 CCR rule. Consequently, the Company prepared
14 and placed in the facility's operating record a notice of intent to initiate closure on
15 December 11, 2015, in accordance with §257.100. The Monroe Bottom Ash Basin
16 was therefore considered an inactive CCR surface impoundment. Section 257.100
17 was later remanded and revised by EPA, subjecting inactive CCR surface
18 impoundments to all the requirements applicable to existing CCR surface
19 impoundments but on an alternative timeframe. In April 2020, it was determined
20 that the Monroe Bottom Ash Basin did not meet the requirements of §257.60
21 (placement above the uppermost aquifer) and was subject to closure under the
22 requirements of §257.101(b)(1)(i) and therefore must cease receipt of both CCR
23 and non-CCR waste streams as soon as technically feasible, but no later than April
24 11, 2021, and close in accordance with §257.102. The Company ceased receipt of

Line
No.

1 non-CCR waste streams and initiated closure on October 21, 2020 and is currently
2 progressing through final steps of closure by removal of all CCR.

3

4 **Q32. Please explain why the site improvements at Sibley Quarry Landfill are**
5 **necessary and needed to support CCR compliance.**

6 A32. Improvements to infrastructure at Sibley Quarry Landfill have been made to
7 enhance the storage capability to accept the CCR material from the Monroe Bottom
8 Ash Basin and Monroe Power Plant production CCR. These improvement projects
9 were necessary because the Monroe Fly Ash Basin and Vertical Extension Landfill
10 could not accept CCR beyond 2023. Sibley Quarry Landfill has ample permitted
11 capacity and was therefore selected as the disposal location for the CCR material
12 removed from the Monroe Bottom Ash Basin, and Monroe production CCR. The
13 Company has transported nearly 1,000,000 tons of CCR from the Monroe Bottom
14 Ash Basin through 2023 and will receive additional CCR material in 2024.
15 Certification of the CCR removal from the Monroe Bottom Ash Basin is expected
16 by late 2024. Company Witness Guillaumin details the costs associated with these
17 improvement projects.

18

19 **Q33. Please explain why the Monroe Fly Ash Basin Closure project is necessary and**
20 **what are the required closure time frames.**

21 A33. The Monroe Fly Ash Basin is an existing unlined CCR surface impoundment as
22 determined under 40 C.F.R. §257.71(a). Therefore, it is subject to the requirements
23 of 40 C.F.R. §257.101(a)(1), which states that the unit must cease receipt of waste
24 and initiate closure as soon as technically feasible, but by no later than April 11,
25 2021. As discussed in Question 26 above, the Company submitted a Part B

Line
No.

1 Alternate Liner Demonstration Application for the Monroe Fly Ash Basin on
2 November 30, 2020, in accordance with 40 C.F.R. §257.71(d)(1). On January 11,
3 2022, EPA notified the Company that the application was administratively
4 complete, and that EPA will pause the facility's deadline to cease receipt of waste
5 until issuance of a final decision under 40 C.F.R. §257.71(d)(2)(iii)(C). The
6 Company has not received a final decision under 40 C.F.R. §257.71(d)(2)(iii)(C)
7 as of this filing. However, the Monroe Fly Ash Basin received the known final
8 receipt of waste on December 29, 2023, and initiated closure within 30 days to
9 comply with 40 C.F.R. §257.102(e)(1). As documented in the Notification of Intent
10 to Close, the Company has ceased receipt of waste and initiated closure.

11

12 To comply with the closure timeframes of 40 C.F.R. §257.102(f)(1), the Company
13 must complete closure within five years of commencing closure activities.
14 Therefore, the Company is targeting 2029 to complete the closure of this 410-acre
15 basin. If needed, 40 C.F.R. §257.102(f)(2) provides an opportunity for up to five
16 2-year extensions, provided the owner or operator can demonstrate the factual
17 circumstances which prevented completion of closure within the baseline five
18 years.

19

20 **Q34. Can you describe how EPA's proposed Legacy CCR Rule could affect or alter**
21 **planned capital projects to comply with the current CCR rule?**

22 A34. Yes. The proposed Legacy CCR Rule does not affect the planned capital projects
23 being implemented to comply with the current CCR Rule. On May 18, 2023, EPA
24 published a proposed rule titled Hazardous and Solid Waste Management System:
25 Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR

Line
No.

1 Surface Impoundments. The draft rule proposes to establish regulatory
2 requirements for inactive surface impoundments at inactive facilities, and also
3 apply groundwater monitoring, corrective action, closure, and post closure care
4 requirements for all CCR Management Units (CCRMU) at regulated CCR
5 facilities. Importantly, the proposed rule applies to currently unregulated CCR, and
6 the CCR-related capital projects described in Witness Guillaumin's testimony are
7 tied to regulated CCR units that will proceed as planned.

8

9 **Q35. Does this complete your direct testimony?**

10 A35. Yes, it does.

1 JUDGE WALLACE: Please go ahead.

2 MS. REITZEL: Thank you, your Honor.

3 Next, DTE would move to bind into the record the direct
4 testimony of Habeeb J. Maroun, consisting of a cover
5 sheet and 28 pages of questions and answers, and for the
6 admission of nine direct exhibits and schedules,
7 designated as Exhibit A-16 Schedule F1.1, Exhibit A-16
8 Schedule F1.2, Exhibit A-16 Schedule F1.3, Exhibit A-16
9 Schedule F1.4, Revised Exhibit A-16 Schedule F1.5,
10 Exhibit A-16 Schedule F1.6, Exhibit A-16 Schedule F1.7,
11 Exhibit A-16 Schedule F1.8, and Exhibit A-33 Schedule X6.
12 He also had rebuttal testimony consisting of a cover
13 sheet with 20 pages of questions and answers, and two
14 rebuttal exhibits, designated as Exhibit A-38 Schedule
15 CC1, and Exhibit A-38 Schedule CC2.

16 JUDGE WALLACE: Thank you. Is there any
17 objection to binding in the direct and rebuttal testimony
18 of Mr. Maroun?

19 Hearing none, the testimony is bound in.

20 Is there any objection to the exhibits or
21 associated schedules sponsored by Mr. Maroun? (No
22 response.)

23 (Testimony bound in.)

24 - - -

25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
18 A-16	F1.1	UCOS, Production by Customer Class,
19		TME December 31, 2025
20 A-16	F1.2	UCOS, Distribution by Voltage Class,
21		TME December 31, 2025
22 A-16	F1.3	Functionalization and Allocation Overview
23		
24 A-16	F1.4	Customer Charges by Voltage Class

- I performed forecast test year UCOS studies that apply the allocation 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
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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
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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
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1 accounts receivable is functionalized based on net plant. Miscellaneous revenue is
2 functionalized using a combination of direct assignment and allocation.

3

4 **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

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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

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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
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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
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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

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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-

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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.

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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

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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?**

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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
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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
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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?**

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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
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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.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

HABEEB J. MAROUN

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF HABEEB J. MAROUN

Line
No.

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

3 A1. My name is Habeeb J. Maroun (he/him/his). My business address is One Energy
 4 Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate
 5 Services, LLC, a subsidiary of DTE Energy Company as a Regulatory Strategy
 6 Consultant, Regulatory Economics.

7

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

10 A2. Yes.

11

12 **Q3. Are you sponsoring any rebuttal exhibits in this proceeding?**

13 A3. Yes. I am sponsoring the following two exhibits:

14 1) U-21534 Exhibit A-38 Schedule CC1 System Demand Tests

15 2) U-21534 Exhibit A-38 Schedule CC2 SRM Capacity Charge Comparison

16

17 **Purpose of Testimony**

18 **Q4. What is the purpose of your rebuttal testimony?**

19 A4. The purpose of my testimony is to respond to intervenor direct testimony,
 20 specifically addressing the topics listed below. The absence of rebuttal on any
 21 given matter does not constitute agreement by the Company.

22 1) Respond to Michigan Environmental Council, Natural Resources Defense
 23 Council, Sierra Club, and Citizens Utility Board of Michigan (MNSC)
 24 Witnesses Jester's and Denzler's proposal to replace 4 Coincident Peak (CP) in
 25 the Cost-of-Service Study (COSS);

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- 1 2) Respond to MNSC Witnesses Jester's and Woolley's proposal to analyze
- 2 seasonality and distribution costs in the next rate case;
- 3 3) Respond to Energy Michigan Zakem's proposal to alter the State Reliability
- 4 Mechanism (SRM) capacity charge calculation;
- 5 4) Respond to MPSC Staff's (Staff) proposed change to the allocation of
- 6 purchased power capacity in the COSS as sponsored by Staff Witness Pung;
- 7 5) Respond to errors in Staff's as-filed COSS model.

8

9 **Recommendations**

10 **Q5. Please summarize your conclusions and recommendations to the Commission.**

11 A5. My conclusions and recommendations are outlined below:

12

13 **MNSC Proposals**

- 14 1) The continued application of the Commission-approved 4 CP method for the
- 15 production plant allocator is appropriate. The updated system demand tests
- 16 confirm DTE continues to be a summer peaking utility supporting the use of
- 17 the 4 CP method. Witnesses Jester and Denzler have not shown that their
- 18 proposals, argued based on changes to the MISO-construct, more appropriately
- 19 reflect the cost drivers for the \$10 billion of production plant embedded costs
- 20 in the Company's revenue requirement.

21

22 Additionally, the current 4 CP method for the allocation of capacity revenue
23 requirement, as detailed in Exhibit A-16 Schedule F1.5 (capacity charge
24 revenue requirement by class), should remain as is. Any changes should only

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1 be considered if the Commission decides to alter the existing 4 CP method for
2 apportioning production plant costs.

3 2) The suggestion by Witness Jester for the Company to perform an analysis on
4 seasonality and distribution costs for the upcoming rate case is deemed
5 insufficiently detailed. Additionally, the Company opposes the consideration
6 of alternatives to the Commission-approved class NCP allocators for
7 apportioning distribution plant costs by voltage level, particularly based on
8 summer peak demands. Company Witness Deol rebuts Witness Woolly's
9 assertions. Finally, the increased complexity that Witnesses Jester's and
10 Woolly's proposed analysis would add to the COSS in terms of time and
11 resources required for completion, in addition to the absence of clearly defined
12 benefits, lead to the conclusion that this recommendation should not be
13 considered.

14

15 Energy Michigan Proposal

16 3) If purchased power energy were reclassified as capacity costs as asserted by
17 Witness Burgdorf in his rebuttal testimony, this reclassification would not alter
18 the SRM capacity charge from the Company's as-filed amount.

19

20 MPSC Staff Proposal

21 4) The Company proposes to continue allocating purchased power capacity using
22 4 CP 100-0-0 demand less R10 (allocator 251) and purchased power energy
23 using 0-0-100 energy less R10 (allocator 111). Should the Commission agree
24 with Staff's proposal to align the allocation of purchased power capacity and
25 with the current allocator used for production plant using allocator 255 (4 CP

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1 75-0-25), it would also be prudent to ensure consistency in the corresponding
2 allocation of purchased power energy and fuel costs. Currently, fuel costs are
3 allocated using allocator 192 (12 CP 10-0-90).

4 5) Errors pertaining to the following items should be corrected in the COSS model
5 corresponding to the final order:

6 a. D13 Incremental Distribution Revenues: update amount by performing
7 a single iteration of COSS and rate design prior to calculation of final
8 rates;

9 b. Low Income and Senior Discounts: update COSS model to match
10 approved amounts.

11

12 **MNSC Proposal to Replace 4 Coincident Peak (CP) in the COSS**

13 **Q6. Does MNSC Witness Jester take issue with the currently approved production**
14 **plant cost allocator, 4 CP 75-0-25?**

15 A6. Yes. In his direct testimony, MNSC Witness Jester does not suggest any
16 modifications to the 75-0-25 segment of the production plant allocation formula
17 (allocator 255). His critique is directed exclusively at the 4 Coincident Peak (CP)
18 measurement. On page 13, lines 10 to 11, Jester states, “I am focusing on only one
19 of the methods about which I disagree with DTE Electric’s proposal, the use of 4CP
20 to allocated Production Plant.” He then proceeds to outline two alternative
21 approaches to the 4 CP method, details of which will be elaborated upon later in
22 this rebuttal testimony.

23

24 **Q7. Has the 4 CP allocator been previously approved by the Commission?**

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1 A7. Yes. The MPSC Commission initially approved the inclusion of the 4 CP
2 measurement within the production plant allocation in Case No. U-17689. This
3 methodology has since received consistent approval across the Company's
4 subsequent seven electric rate cases, specifically Case Nos. U-17767, 18014,
5 18255, 20162, 20561, 20836, and 21297.

6

7 **Q8. Why does Witness Jester disagree with the applicability of the 4 CP allocator?**

8 A8. In his direct testimony, Jester asserts that the DTE Electric production plant
9 requirements are not directly determined by customer demand. Based on his view,
10 this is due to potential fulfillment of power by other participants within MISO.
11 Furthermore, he suggests that during non-summer seasons with capacity
12 constraints, there may be a need for additional capacity resources to meet demand.
13 The selected excerpts underscore the key points of Jester's testimony.

14

15 "The power consumed by DTE Electric's customers will often be provided, at
16 least in part, by resources owned by other MISO market participants.
17 Consequently, DTE Electric's Production Plant requirements are not directly
18 determined by the demand from its own customers." (page 14 lines 18 to 21)

19

20 He further explains:

21

22 "With the combination of both seasonal reserve margins and seasonal
23 accreditation, it is entirely possible that customer demand in some season will
24 drive a need for additional Production Plant resources even though demand in
25 that season is distinctly lower than in the 4CP summer that DTE Electric has

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1 traditionally used. The Commission should conclude from MISO's seasonal
2 Resource Adequacy construct that Production Plant cost causation can no
3 longer be based solely on class contribution to peak nominal loads but instead
4 must be rooted in the seasonal performance of those resources." (page 17 lines
5 7 to 13)

6

7 Finally, he argues:

8

9 "The utilization of DTE Electric's Production Plant portfolio is distinctly lower
10 in Winter (71.9%) but varies only a little amongst the other seasons (between
11 96.5% and 98.4%). This pattern of utilization of DTE Electric's Production
12 Plant portfolio does not support the use of the 4 CP metric." (page 18, lines 2
13 to 5)

14

15 **Q9. What is your response to these arguments?**

16 A9. The 4 CP measurement was first sanctioned by the MPSC Commission in their
17 order dated June 15, 2015 for Case No. U-17689. This approval was grounded on
18 the four system demand tests presented by DTE Electric Witness Martin L. Heiser.
19 The Order in that case did not consider the MISO resource adequacy construct,
20 which was not factored into the decision-making process regarding the adoption of
21 the 4 CP approach. Consequently, the ongoing modifications to MISO's resource
22 adequacy approach are irrelevant and should not influence the decision to continue
23 with the 4 CP methodology in the instant case. Witness Jester has not explained,
24 regardless of the specifics of MISO's resource adequacy framework, why it is
25 appropriate to change the 4 CP production plant allocation approach to one

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1 premised on MISO considerations when, as I describe above, the Commission has
2 consistently used a different method for the last nine years.

3

4 **Q10. Can you summarize the Commission's determination in Case No. U-17689 that**
5 **the demand portion of production plant costs should be allocated using 4 CP?**

6 A10. The Commission conducted an evaluation of cost allocation methods in DTE
7 Electric's Case No. U-17689. The pivotal findings of the Commission, as stated on
8 page 20 of its June 15, 2015 order, pertain to the allocation of costs related to
9 production plant. The key conclusions of the Commission in the order with respect
10 to the allocation of production plant are provided below:

11

12 *The Commission agrees with DTE Electric, the Staff, and*
13 *ABATE, that a change from a 12CP to a 4CP demand allocator*
14 *is fully supported by the evidence presented in this proceeding.*
15 *Martin L. Heiser, Consultant, Regulatory Economics for DTE*
16 *Energy Corporate Services, LLC, explained that the company*
17 *applied four system demand tests that have been used by the*
18 *Federal Energy Regulatory Commission to determine the*
19 *appropriate demand portion of the allocator. The results of these*
20 *tests are consistent with the results for other utilities for which*
21 *FERC has authorized a 4CP allocator. See, 2 Tr 234-236;*
22 *Exhibit A-14. The Commission therefore rejects the ALJ's*
23 *recommendation to retain the 12CP demand allocator.*

24 Moreover, Commissioner White stated in his opinion on page 41 of the order,
25 "Based on the evidentiary record, I do agree with the shift to 4 CP from the
26 previously authorized 12 CP method. In that respect, I agree that DTE Electric is a
27 summer peaking company."

28

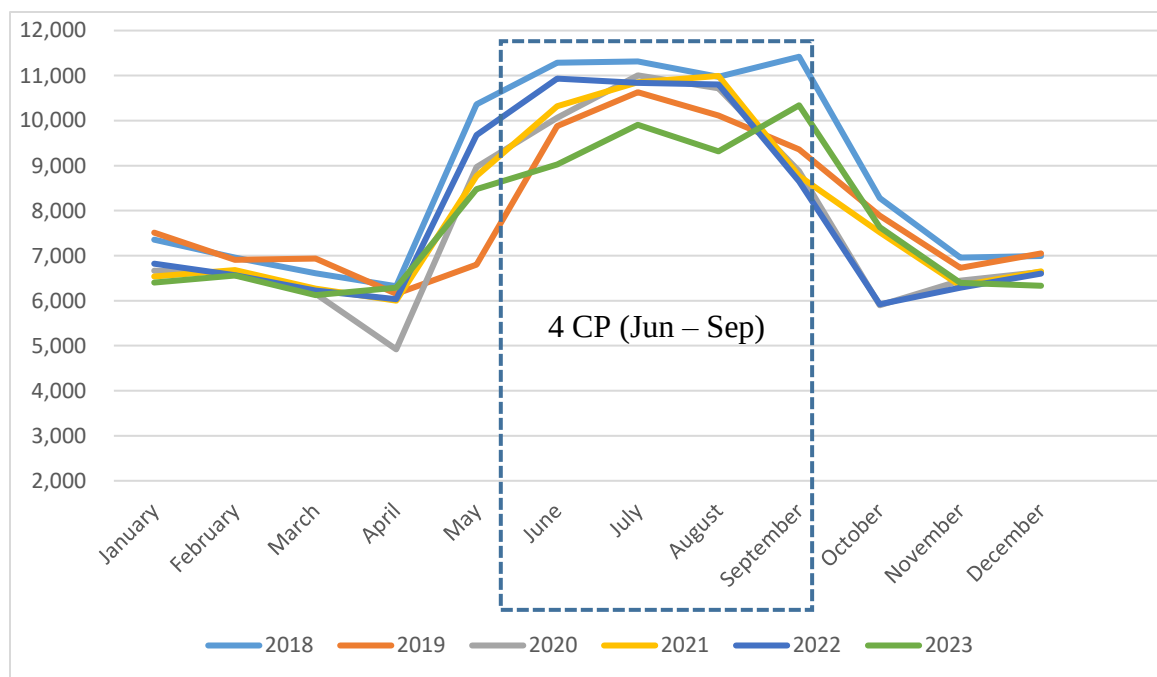
29 **Q11. Have you updated the four system demand tests utilized by Witness Heiser in**
30 **Case No. U-17689 to determine whether 4 CP is still appropriate?**

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1 A11. Yes. The tests have been updated as illustrated in Exhibit A-38 Schedule CC1 of
2 this rebuttal testimony, incorporating data from the most recent six-year period,
3 spanning from 2018 to 2023. This update reflects the monthly system peaks as
4 reported in DTE's MPSC P-521 reports on page 401b. Additionally, Figure 1
5 below offers a graphical representation of the monthly system peaks employed in
6 the updated tests.

8 **Figure 1 : DTE Electric Monthly System Peak Demands (MW)**

9 **2018 to 2023 (MPSC P-521, pg. 401.b)**



10

11 **Q12. What are the results of the updated tests shown in Exhibit A-38 Schedule CC1?**

12 A12. For test 1, where large differences between the annual peak and the average peak
13 lends support for using something other than 12 CP, DTE Electric's 4 CP ratio was
14 31% (previously 30%), near the upper bound of 31% for the four out of six cases

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1 where a method other than 12CP was allowed in the Guide¹. For test 2 examining
2 the lowest monthly peak as a percentage of annual peak, where higher percentages
3 indicate greater support for 12 CP, DTE's six year average was 54% (previously
4 55%), consistent with the range of results for the 6 out of 14 cases where a method
5 other than 12 CP was allowed in the Guide¹. The 8 out of 14 cases where the 12
6 CP method was allowed had percentages in excess of 70%. For test 3, none of DTE
7 Electric's monthly peaks occurring in the off-peak months exceeded the average
8 monthly peaks within the four peak months of June through September (consistent
9 with prior findings). For test 4, the six year average of the 12 peaks as a percentage
10 of the single high peak was 74% (previously 72%), below the minimum value of
11 81% exhibited by the 5 out of 8 cases where the 12 CP method was allowed.

12

13 **Q13. What is your conclusion based on these results?**

14 A13. The updated results, as detailed previously and illustrated in Exhibit A-38 Schedule
15 CC1, conclusively indicate that the 4 CP method remains the appropriate metric for
16 assessing the demand component of the production plant's cost allocation.
17 Consequently, the current method is validated, and no modifications are necessary.

18

19 **Q14. Can you describe the two options that Jester proposes to replace 4 CP?**

20 A14. Jester presents two options to replace the 4 CP method in his direct testimony,
21 which I have summarized below.

22

¹ A Guide to FERC Electric Utility Ratemaking (Guide), by Michael E. Small, Wright & Talisman, P.C.,
©1989 by Atlantic Information Services Inc.

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1 *Option 1 (page 18, lines 10 to 11): “The first option is to use 9CP, averaging the*
2 *customer class contributions to peak load in each of the months in Spring, Summer,*
3 *and Fall (March through November).”*

4

5 *Option 2 (page 19, lines 1 to 23): this option is referred to as the Weighted Seasonal*
6 *Capacity Increment (WSCI) by Witnesses Jester and Denzler. The following are a*
7 *summarized list of steps to calculate this option based on Witness Jester’s*
8 *testimony:*

- 9 ○ Allocate 71.9% of measurement using winter utilization and 12 CP
- 10 ○ Allocate 24.6% of measurement (96.5% spring utilization less 71.9%
- 11 winter utilization) using 9 CP covering spring, summer, and fall
- 12 ○ Allocate 1.6% of measurement (98.2% fall utilization less 96.2% spring
- 13 utilization) using 6 CP covering summer and fall
- 14 ○ The remaining 1.8% of the measurement is allocated based on 3 CP
- 15 covering summer

16

17 This proposal is effectively a blended weighting of 12 CP (71.9 percent) and 9 CP

18 24.6 percent), which comprise over 96 percent of the demand measurement.

19

20 **Q15. What is your opinion of Jester’s option 1 (9 CP)?**

21 A15. The Commission has already established that the demand component of the

22 production plant cost allocator is accurately represented by 4 CP. This was further

23 corroborated by the updated system demand tests presented in Exhibit A-38

24 Schedule CC1, which affirmed the ongoing application of 4 CP as a valid method.

25

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1 Interestingly, option 1 lacks a strong endorsement from Witness Jester, as he
2 indicates his preference for option 2 on page 18 lines 15 to 18: “However, this
3 approach (option 1) does not actually adjust the nominal MW of customer demand
4 for the seasonality of the resources needed to support that load. I recommend
5 adopting my second option.”

6

7 **Q16. What is your opinion of Jester’s option 2 (WSCI)?**

8 A16. The option 2 proposal warrants rejection due to the lack of compelling evidence
9 from Witness Jester that the 4 Coincident Peak (4 CP) method is obsolete, or that
10 the WSCI proposal more accurately represents the primary cost drivers for the \$10
11 billion in embedded costs of production plant in the as-filed Production COSS.
12 Additionally, the MISO Seasonal Resource Adequacy construct, which was
13 implemented in 2023, is relatively new. Consequently, there is insufficient data to
14 fully comprehend the potential fluctuations in the apportionment of production
15 plant costs across different classes over time based on this proposal. Moreover, as
16 I describe above, the MISO construct has never been the basis for utilizing 4 CP for
17 the demand portion of production plant and, as such, the fact that the MISO construct
18 is changing is not itself a basis to utilize it. Witness Jester offers no affirmative
19 argument for why using a MISO-basis is fundamentally more appropriate than the
20 longstanding, Commission approved approach to production plant cost allocation.

21

22 **Q17. What additional concerns do you have with these proposals?**

23 A17. Witness Jester states on page 17 lines 7 to 10 that “With the combination of both
24 seasonal reserve margins and seasonal accreditation, it is entirely possible that
25 customer demand in some season will drive a need for additional Production Plant

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1 resources even though demand in that season is distinctly lower than in the 4CP
2 summer that DTE Electric has traditionally used.” This perspective is speculative
3 (“it is entirely possible”) and focused on incremental resources while ignoring the
4 primary drivers and conditions that drove the embedded costs of capacity incurred
5 by DTE to serve its customers.

6

7 **Q18. Did MNSC evaluate the class impacts of utilizing the allocators sponsored by**
8 **Witness Jester ?**

9 A18. Yes. Witness Denzler, after receiving options 1 and 2 as calculated by MNSC
10 Witness Jester, proceeds to update the Company’s as-filed Production COSS and
11 provides the revenue requirement impacts on customer classes in Figure 1 of his
12 direct testimony. He concludes with a recommendation, specifically on page 19,
13 lines 19 to 20 to “adjust the UCOS Production allocations based on the
14 recommendations of the MNSC Witness Jester.”

15

16 **Q19. Do you have any observations regarding the class impacts of Witness Jester’s**
17 **proposals as provided by Witness Denzler in his Figure 1 table?**

18 A19. Yes. I have concerns regarding the large increases to the D2 Residential Space
19 Heating class resulting from Witness Jester’s allocation proposals. While the
20 Company calculated an as-filed production revenue requirement of \$20.630 million
21 for the D2 Residential Space Heating class, Witness Jester’s option 1 proposal
22 would increase the amount to \$66.481 million and his option 2 proposal would
23 increase the amount to \$63.214 million. Both proposals reflect increases of greater
24 than 200 percent. Such drastic hikes in costs would be detrimental to the customers
25 in this class, and suggests structural inconsistencies in the analysis that should give

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1 the Commission substantial pause when considering it as evidence in support of the
2 proposal.

3

4 **Q20. Please provide a summary of your conclusions and recommendations**
5 **regarding Witness Jester and Denzler's arguments and proposals?**

6 A20. The following are my conclusions and recommendations:

7 The continued application of the Commission-approved 4 CP method for the
8 production plant allocator is appropriate. The updated system demand tests confirm
9 DTE continues to be a summer peaking utility supporting the use of the 4 CP
10 method. Witnesses Jester and Denzler have not shown that their proposals, argued
11 based on changes to the MISO-construct, more appropriately reflect the cost drivers
12 for the \$10 billion of production plant embedded costs in the Company's revenue
13 requirement.

14

15 Additionally, the current 4 CP method for the allocation of capacity revenue
16 requirement, as detailed in Exhibit A-16 Schedule F1.5 (capacity charge revenue
17 requirement by class), should remain as is. Any changes should only be considered
18 if the Commission decides to alter the existing 4 CP method for apportioning
19 production plant costs.

20 **MNSC Witness Jester's Proposal to Analyze Seasonality and Distribution Costs in**

21 **Next Rate Case**

22 **Q21. What is MNSC Jester's recommendation regarding seasonality?**

23 A21. On page 28, lines 1 to 3, Witness Jester recommends that "the Commission require
24 that DTE Electric file in its next rate case an analysis of the seasonality for cost

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1 causation of distribution costs and distribution rate designs consistent with that
2 seasonality.”

3

4 **Q22. What is MNSC Witness Woolley’s opinion on this issue?**

5 A22. In his direct testimony on lines 1 to 10 of page 11, Witness Woolley expresses
6 disagreement with the allocation for “distribution system maintenance and
7 upgrades based on peak loads,” stating that it does not properly reflect the factors
8 that contribute to transformer aging.

9

10 **Q23. How does MNSC Witness Jester support his recommendation on this issue?**

11 A23. Witness Jester’s argument is largely based on the accounts of MNSC Witnesses
12 Gard and Woolley. Witness Jester states on page 23 lines 10 to 18 of his direct
13 testimony, “As MNSC witness Graham Woolley shows, the effective capacity of
14 the distribution system is also seasonal. Currently aging of line transformers occurs
15 almost exclusively occurs during Summer months June through August. As both
16 he and MNSC witness David Gard show, utilization of the effective capacity of the
17 distribution system is highly seasonal, both because nominal loads are lower in non-
18 summer seasons but also because transformer effective rating is higher when
19 ambient temperatures are lower. As with Production Plant capacity that varies
20 seasonally, the proper basis for both cost of service and rate design of distribution
21 costs is the degree of capacity utilization, not nominal loading.”

22

23 Additionally, he states on page 24 lines 20 to 22 that “we are presenting the
24 transformer analysis to illustrate that this is a significant consideration, but ambient

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1 temperature is important to most elements of the distribution system and should be
2 considered across all of those elements. “
3

4 **Q24. How do you respond to Witnesses Jester and Woolley?**

5 A24. DTE Witness Deol will address the technical points raised by MNSC Witness
6 Woolley while I will respond to the COSS implications. As for the
7 recommendations and defined benefits of Witnesses Jester’s and Woolley’s
8 proposal, they are ambiguous. Witness Woolley has voiced objections to the
9 current method of allocating transformers but hasn’t offered any alternative
10 methods for consideration. Meanwhile, Witness Jester notes that transformer aging
11 mainly occurs during the summer and urges DTE to conduct “an analysis of the
12 seasonality affecting the causation of distribution costs and the corresponding rate
13 designs,” yet he fails to provide concrete details for evaluation. It is unclear if
14 Witness Jester is suggesting an independent study or a supplemental COSS to
15 assess the seasonality of distribution cost causation. Questions such as whether the
16 study should cover only plant costs or include operating and maintenance expenses,
17 or whether it should encompass an examination of distribution allocators in the
18 COSS are not addressed in MNSC’s testimony. The Company would not have
19 sufficient time to review these details in the event they are provided later in this
20 proceeding. Besides the previously mentioned reasons, the Company believes it
21 should not be required to invest the significant time and resources needed to
22 perform a study, merely because an intervenor might be curious or to fill some
23 undefined future data interest.
24

25 **Q25. Do you have any other objections to their proposal?**

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1 A25. Yes. Integrating seasonal variations into the distribution COSS model, taking into
2 account Witness Jester's assertion that transformer aging "almost exclusively
3 occurs during Summer months June through August" appears to support the idea
4 of allocating distribution costs based on summer peak demands when ambient
5 temperatures and customer loads are simultaneously at their highest. This approach
6 would align with the use of 4 CP method for allocating the demand portion of
7 production plant costs. However, the Company disagrees with this approach as it
8 deviates from the Commission-approved non-coincident class peak (NCP)
9 allocators.

10

11 Moreover, it is crucial to weigh the benefits of incorporating seasonality against the
12 risk of complicating the COSS model further. The existing model is already
13 extensive, with over forty workpapers, nearly ninety allocation schedules, and
14 thousands of Excel rows. Adding seasonal factors could expand its complexity
15 without any evidence that it would yield a more accurate result.

16

17 **Q26. Please summarize your recommendation on this topic.**

18 A26. The suggestion by Witness Jester for the Company to perform an analysis on
19 seasonality and distribution costs for the upcoming rate case is deemed
20 insufficiently detailed. Additionally, the Company opposes the consideration of
21 alternatives to the Commission-approved class NCP allocators for apportioning
22 distribution plant costs by voltage level, particularly based on summer peak
23 demands. Company Witness Deol rebuts Witness Woolly's assertions. Finally, the
24 increased complexity that Witnesses Jester's and Woolly's proposed analysis
25 would add to the COSS in terms of time and resources required for completion, in

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1 addition to the absence of clearly defined benefits, lead to the conclusion that this
2 recommendation should not be considered.

3

4 **Energy Michigan Zakem's proposal to alter the State Reliability Mechanism (SRM)**
5 **capacity charge calculation**

6 **Q27. What is your response to Energy Michigan Witness Zakem's proposal to**
7 **remove \$260.787 million of fuel cost in the SRM capacity charge?**

8 A27. DTE Witness Burgdorf addresses the points raised by Witness Zakem while I will
9 address the impacts to the SRM capacity charge. DTE Witness Burgdorf asserts in
10 rebuttal that excluding the \$260.787 million of purchased power energy from the
11 "energy sales revenue net of fuel costs" in Exhibit A-26 would reclassify this
12 expenditure as a capacity-related costs. Witness Burgdorf requested I perform an
13 analysis of how treating the purchased power energy as a capacity cost would affect
14 the SRM capacity charge.

15

16 Exhibit A-38 Schedule CC2 offers a comparative analysis of DTE's as-filed SRM
17 capacity charge, detailed in column (a) of the exhibit. It also includes the revised
18 calculation in column (b), which integrates the reclassification of the \$260.787
19 million as capacity cost as asserted by Witness Burgdorf. The analysis indicates
20 the SRM capacity charge remains unchanged.

21

22 **Q28. What is your conclusion on this topic?**

23 A28. If purchased power energy were reclassified as capacity costs as asserted by Witness
24 Burgdorf in his rebuttal testimony, this reclassification would not alter the SRM
25 capacity charge from the Company's as-filed amount.

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1 **Staff Proposal to Modify Allocation of Purchased Power Capacity in COSS**

2 **Q29. Can you describe Staff Witness Pung's proposal to change the allocation of**
3 **purchased power capacity in the COSS?**

4 A29. Staff Witness Pung describes his proposal on page 12, lines 22 to 26 of his direct
5 testimony, stating that "Staff recommends that allocator 255 be used to allocate
6 purchased power capacity costs in alignment with the Commission's long-standing
7 practice of recognizing the dual nature of production assets. Allocator 255 is a 4
8 CP 75/0/25 allocator and would align the Company with Michigan's other large
9 electric provider, Consumers Energy Company."
10

11 **Q30. What is the current allocation of purchased power capacity and energy costs**
12 **in the DTE Electric's COSS ?**

13 A30. The division of purchased power into capacity and energy costs is provided by
14 Company Witness Burgdorf in Exhibit A-26 and imported into the COSS. The
15 ongoing use of direct demand and energy allocators for the allocation of these costs
16 within the COSS is an appropriate reflection of cost-causation. The Company
17 allocates purchased power capacity using 4 CP 100-0-0 demand less R10 (allocator
18 251) and purchased power energy using 0-0-100 energy less R10 (allocator 111).
19 These allocators have been consistently applied in the calculation of approved
20 tariffs in the previous seven DTE electric rate cases by DTE (U-17767, 18014,
21 18255, 20162, 20561, 20836, and 21297).
22

23 **Q31. What is your recommendation on this issue?**

24 A31. The Company proposes to continue allocating purchased power capacity using 4
25 CP 100-0-0 demand less R10 (allocator 251) and purchased power energy using 0-

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1 0-100 energy less R10 (allocator 111). Should the Commission agree with Staff
2 Witness Pung's proposal and change the allocation to align the allocation of
3 purchased power capacity with the current allocator use for production plant using
4 allocator 255 (4 CP 75-0-25), it would also be prudent to ensure consistency in the
5 allocation of purchased power energy and fuel costs. Currently, fuel costs are
6 allocated using using allocator 192 (12 CP 10-0-90).

7

8 **MPSC Staff As-Filed Excel COSS Model Errors**

9 **Q32. Did you identify any errors in MPSC Staff's as-filed Excel COSS model?**

10 A32. Two minor errors were identified in Staff's as-filed Excel COSS model which
11 should be corrected for the final order.

12

13 1) D13 Incremental Distribution Revenue (COSS Model - Input 1 tab; Row 285):

14 Staff did not update the Company's as-filed \$59 thousand of D13 incremental
15 distribution revenues in the COSS model. DTE calculated a value of \$32
16 thousand using Staff's as-filed numbers. Since D13 incremental distribution
17 revenue is based on proposed primary and transmission rates, it requires a single
18 iteration of distribution COSS and rate design using the steps below:

19 a. First, proposed D13 distribution revenue needs to be calculated in the
20 Rate Design model based on interim proposed transmission and primary
21 rates; these interim proposed rates are calculated based on an interim
22 distribution COSS;

23 b. Second, after proposed D13 distribution revenue has been calculated in
24 the Rate Design model, this value should then be input on Line 7 of tab

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1 “B21.2 D13 Rev” in my workpaper model; this calculates the final value
2 of D13 incremental distribution revenue;

3 c. Finally, the D13 incremental distribution revenue amount should be
4 input on Excel row 285 of the Input 1 tab in the COSS model.

5 2) The Low Income and Senior discounts on Row 265-267 of the Input 1 tab in
6 the COSS model do not match Staff’s as filed numbers.

7

8 **Figure 2 Staff As-Filed and COSS - Low Income / Senior Credits**

(\$ thousands)		Staff As-Filed	Staff COSS
	RIA	\$5,726	-
	LIA	<u>15,360</u>	-
	Total Low Income	21,086	\$30,406
	Senior	4,821	5,810

9

10 **Q33. Can you summarize your recommendations on this topic?**

11 A33. The errors pertaining to the following items should be corrected in the COSS model
12 corresponding to the final order:

13 a) D13 Incremental Distribution Revenues: update amount by performing a single
14 iteration of COSS and rate design prior to calculation of final rates;

15 b) Low Income and Senior Discounts: update COSS model to match approved
16 amounts.

17

18 **Q34. Does this conclude your rebuttal testimony?**

19 A34. Yes, it does.

1 JUDGE WALLACE: O.K., please go ahead.

2 MS. REITZEL: Thank you, your Honor.

3 We -- the Company would now move to bind into the record
4 the Revised Direct Testimony of Kirk M. Vangilder, which
5 consists of a cover sheet and 21 pages of questions and
6 answers, with 16 direct exhibits, designated as Exhibit
7 A-1 Schedule A1, Exhibit A-2 Schedule B2, Exhibit A-3
8 Schedule C2, Exhibit A-3 Schedule C12, Exhibit A-3
9 Schedule C13, Exhibit A-4 Schedule D1, Exhibit A-11
10 Schedule A1, Exhibit A-11 Schedule A1.1, Exhibit A-11
11 Schedule A1.2, Exhibit A-12 Schedule B1, Exhibit A-13
12 Schedule C2, Exhibit A-13 Schedule C14, Exhibit A-13
13 Schedule C15, Exhibit A-14 Schedule D1, Exhibit A-33
14 Schedule X4, and Exhibit A-33 Schedule X5. There is no
15 rebuttal testimony or associated exhibits.

16 JUDGE WALLACE: Thank you. Is there any
17 objection to binding in the revised direct testimony of
18 Mr. Van -- I'm sorry, is it Vangilder or Vanglider?

19 MS. REITZEL: Vangilder,
20 V-a-n-g-i-l-d-e-r.

21 JUDGE WALLACE: Is there any objection to
22 binding in the Revised Direct Testimony of Vangilder.

23 Hearing none, the testimony is bound in.

24 Is there any objection to the exhibits
25 and associated schedules sponsored by Vangilder? (No

1 response.

2 (Testimony bound in.)

3 - - -

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

DIRECT TESTIMONY

OF

KIRK M. VANGILDER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KIRK M. VANGILDER

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

2 A1. My name is Kirk M. Vangilder (he/him/his). My business address is One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
4 Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), within the
5 Regulatory Affairs organization as a Principal Financial Analyst for Revenue
6 Requirements.

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

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

10

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

12 A3. I received a Bachelor of Arts Degree in Accounting from Michigan State
13 University's Eli Broad College of Business in 2004 and a Master of Science Degree
14 in Accounting from Michigan State University's Eli Broad Graduate School of
15 Management in 2006.

16

17 **Q4. Have you completed any seminars or other training courses?**

18 A4. Yes, I have. I completed a utility finance and ratemaking course taught by Excidian,
19 LLC. Additionally, I attended trainings hosted by Electric Utility Consultants, Inc,
20 (EUCI) on utility cost of service and ratemaking. I also completed the ratemaking
21 program conducted by the Institute of Public Utilities at Michigan State University.

22

23 **Q5. What is your work experience?**

24 A5. From 2006 to 2011, I practiced public accounting with the international accounting
25 firm Grant Thornton LLP where I had positions of increasing responsibility.

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1 During this time, I received my Certified Public Accountant license. In October
2 2011, I joined DTE Energy as a Financial Auditor in the Audit Services department.
3 In March 2013 I was promoted to Senior Financial Auditor, where I performed
4 substantive testing and controls testing to support DTE Energy's financial
5 statement audits and regulatory filings process. In August 2014, I accepted a
6 position within DTE Energy's Controllers organization as a Senior Business
7 Financial Analyst with responsibility for various accounting, budgeting, and
8 reporting activities for DTE Gas, including financial and revenue requirement
9 modeling. In 2018, I transferred to Regulatory Affairs as a Senior Rate Analyst in
10 their Revenue Requirements group, and in 2019 I was promoted to my current
11 position as Principal Financial Analyst.

12

13 **Q6. Do you hold any certifications or are you a member of any professional**
14 **organizations?**

15 A6. I received my Certified Public Accountant license in 2008 and am currently a
16 registered accountant within the State of Michigan.

17

18 **Q7. What are your current duties and responsibilities?**

19 A7. As a Principal Financial Analyst for Revenue Requirements within DTE Energy's
20 Regulatory Affairs organization, I am responsible for revenue requirement studies
21 for regulatory filings, regulatory analysis and research, and for supporting certain
22 MPSC filings, such as general rate cases.

23

24 **Q8. Have you previously sponsored testimony before the Michigan Public Service**
25 **Commission (MPSC or Commission)?**

Line
No.

- 1 A8. Yes, I have. I have sponsored testimony in the following cases:
- 2 U-20373 DTE Electric 2020-2021 EWR Plan
- 3 U-20373-A DTE Electric 2020-2021 Amended EWR Plan
- 4 U-20429 DTE Gas 2020-2021 EWR Plan
- 5 U-20642 DTE Gas 2019 Main Rate Case
- 6 U-20703 DTE Electric 2019 EWR Reconciliation
- 7 U-20708 DTE Gas 2019 EWR Reconciliation
- 8 U-20711 DTE Electric 2019 PLD/TRM Reconciliation
- 9 U-20836 DTE Electric 2022 General Rate Case
- 10 U-20876 DTE Electric 2022-2023 EWR Plan
- 11 U-20881 DTE Gas 2022-2023 EWR Plan
- 12 U-20940 DTE Gas 2021 General Rate Case
- 13 U-20987 DTE Electric 2020 PLD/TRM Reconciliation
- 14 U-21206 DTE Electric & DTE Gas 2021 EWR Reconciliation
- 15 U-21242 DTE Electric 2021 Demand Response Reconciliation
- 16 U-21291 DTE Gas 2024 General Rate Case
- 17 U-21297 DTE Electric 2023 General Rate Case
- 18 U-21307 DTE Electric 2021 & 2022 PLD/TRM Reconciliations
- 19 U-21313 DTE Electric & DTE Gas 2022 EWR Reconciliation
- 20 U-21403 DTE Electric 2022 Demand Response Reconciliation

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1 **Purpose of Testimony**

2 **Q9. What is the purpose of your testimony in this proceeding?**

3 A9. I am providing testimony related to the historical and the projected sections of this
4 rate case filing. In Section A – Historical Test Period, I am supporting DTE
5 Electric's historical revenue sufficiency for the twelve months ended December 31,
6 2022. In preparing my rate case exhibits, I relied on financial information supplied
7 by Company Witnesses Uzenski and Lepczyk. I am sponsoring the derivation of
8 the historical overall rate of return, Net Operating Income (NOI) adjustments for
9 interest synchronization and income tax savings, and the revenue conversion factor.

10

11 In Section B – Projected Test Period, I am sponsoring DTE Electric's projected
12 revenue deficiency for the twelve months ending December 31, 2025, as well as the
13 derivation of the projected overall rate of return, the NOI adjustments for interest
14 synchronization and income tax savings, and the projected revenue conversion
15 factor. I also calculate the incremental revenue requirement for DTE Electric's
16 Tree Trim Regulatory Asset and the return on DTE Electric's Monroe Regulatory
17 Asset. In addition, I am supporting the calculation of the incremental revenue
18 requirements for DTE Electric's Infrastructure Recovery Mechanism (IRM), and
19 the Company's proposed reconciliation process should a different amount of IRM
20 capital be placed in service than what has been approved. Lastly, I am supporting
21 the calculation of the incremental revenue requirements for DTE Electric's
22 alternative IRM proposal along with an alternate projected revenue deficiency
23 should the alternative IRM be approved.

24

25 **Q10. Are you sponsoring any exhibits in this proceeding?**

Line
No.

1 A10. Yes. I am supporting the following historical and projected exhibits:

2 Section A – Historical Test Period Ended December 31, 2022

3	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
4	A-1	A1	Historical Revenue Deficiency (Sufficiency)
5	A-2	B1	Historical Rate Base
6	A-3	C2	Historical Revenue Conversion Factor
7	A-3	C12	Historical Tax Effect of Interest Allowed in
8			Ratemaking Formula
9	A-3	C13	Historical Tax Effect of Interest
10			Synchronization Adjustment
11	A-4	D1	Historical Rate of Return Summary

12

13 Section B – Projected Test Period Ending December 31, 2025

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-11	A1	Projected Revenue Deficiency (Sufficiency)
16	A-11	A1.1	Tree Trim Regulatory Asset – Return On
17	A-11	A1.2	Monroe Regulatory Asset – Return On
18	A-12	B1	Projected Rate Base
19	A-13	C2	Projected Revenue Conversion Factor
20	A-13	C14	Projected Tax Effect of Interest
21			Allowed in Ratemaking Formula - 12 Months Ended
22			12/31/2022 and 12/31/2025
23	A-13	C15	Projected Tax Effect of Interest -
24			Synchronization Adjustment - 12 Months Ended
25			12/31/2022 and 12/31/2025

Line
No.

1	A-14	D1	Projected Rate of Return Summary
2			
3	Investment Recovery Mechanism		
4	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
5	A-33	X4	Infrastructure Recovery Mechanism – Incremental
6			Revenue Requirement – Distribution Operations
7	A-33	X5	Infrastructure Recovery Mechanism – Incremental
8			Revenue Requirement – Distribution Operations
9			Example of \$1.0 MM Under Investment

10

11 **Q11. Were these exhibits prepared by you or under your direction?**

12 A11. Yes, they were.

13

14 **Section A – Historical Test Period (Twelve Months Ended December 31, 2022)**

15 **Q12. What information is displayed on Exhibit A-1, Schedule A1?**

16 A12. Exhibit A-1, Schedule A1 titled “Historical Revenue Deficiency (Sufficiency)”
 17 shows the calculation of the Company’s revenue sufficiency for the historical test
 18 period based on historical rate base, overall rate of return, adjusted NOI, and a
 19 revenue conversion factor. Line 8, of Schedule A1 shows that the Company
 20 experienced a revenue sufficiency of \$80.5 million for the historical test period.
 21 The revenue sufficiency is based on a rate base of \$20.1 billion, adjusted NOI of
 22 \$1,132.0 million, and a required rate of return of 5.33%. The rate base balance is
 23 carried forward from Exhibit A-2, Schedule B1. The adjusted NOI is carried
 24 forward from Exhibit A-3, Schedule C1, which is supported by Witness Uzenski.

Line
No.

1 The defined historical required rate of return is set forth in Exhibit A-4, Schedule
2 D1.

3

4 **Q13. What is the Historical Rate Base?**

5 A13. As shown on Exhibit A-2, Schedule B1, Historical Rate Base (line 15) is the end of
6 period balances for net plant amounts for the historical test period and 13-month
7 average balances for the allowance for working capital for the period ended
8 December 31, 2022.

9

10 **Q14. What is the purpose of the Revenue Conversion Factor?**

11 A14. The Revenue Conversion Factor, also known as the Revenue Multiplier, is a
12 multiplication factor that converts a utility's after-tax income deficiency /
13 (sufficiency) into the required change in the pre-tax revenue requirement. In the
14 historical test period, each dollar of revenue the Company received was subject to
15 Michigan Corporate Income Tax, Municipal Income Tax, and Federal Income Tax.
16 Line 9 of Exhibit A-3, Schedule C2, shows DTE Electric's historical test period
17 Revenue Conversion Factor of 1.3496, which means DTE Electric was required to
18 collect \$1.3496 in revenue to produce \$1.00 of after-tax income.

19

20 **Q15. How did you calculate the Income Tax Savings of Interest reflected in Exhibit**
21 **A-3, Schedule C12?**

22 A15. Exhibit A-3, Schedule C12, calculates the difference in the tax deduction amount
23 for interest expense based on interest expense allowable in the rate case versus DTE
24 Electric's actual interest expense for the historical test period as supplied to me by
25 Witness Uzenski. Allowable interest expense starts with the Historical Rate Base

Line
No.

1 (line 1) multiplied by the weighted cost of debt (line 2). The weighted cost of debt
2 is the summation of the weighted costs associated with long-term debt (LTD) and
3 short-term debt (STD) from Exhibit A-4, Schedule D1. Line 3 calculates the
4 allowable ratemaking debt interest expense deduction while DTE Electric's actual
5 interest expense deduction (line 4) is what was included in DTE Electric's
6 computation of federal income tax per Company books. Allowable ratemaking
7 interest expense is less than actual interest expense, which results in reducing the
8 tax deduction by the net of these two amounts. This lower tax deduction increased
9 federal income tax, state income tax and municipal tax expense and creates a
10 corresponding decrease in NOI, as shown on line 11 of Schedule C12.

11

12 **Q16. What is the Synchronization Adjustment calculated on Exhibit A-3, Schedule**
13 **C13?**

14 A16. Tax law requires, and prior Commission Orders have allowed, a return on Job
15 Development Investment Tax Credits (JDITC) at the rate of return for permanent
16 capital. This tax adjustment represents the interest deduction for the debt
17 component of that return and is intended to align the level of interest expense
18 inherent in the capital structure with the Company's rate base. Exhibit A-3,
19 Schedule C13, shows a reduction in state and municipal income tax expense (line
20 7) and federal income tax expense (line 10) due to the interest deduction associated
21 with the debt component portion of JDITC. This Synchronization Adjustment
22 reduces income tax expense and, as shown on line 11, results in a corresponding
23 increase in NOI.

24

25 **Q17. What is DTE Electric's historical rate of return?**

Line
No.

1 A17. Exhibit A-4, Schedule D1, titled “Historical Rate of Return Summary” shows DTE
2 Electric’s historical test period overall rate of return on line 10, column (g). The
3 capital structure is carried forward from the balance sheet on line 119, columns (e)
4 through (i) of Exhibit A-2, Schedule B5 sponsored by Witness Uzenski, and equals
5 the rate base amount on line 15, column (c) of Exhibit A-2, Schedule B1. The
6 capital structure excludes any funds on deposit with trustees, and the financing
7 related to regulatory assets and other items eliminated from the historical balance
8 sheet by Witness Uzenski.
9
10 On Exhibit A-4, Schedule D1, the long-term debt, shown on line 1 includes
11 reductions for the net amount of unamortized premium / discount and unamortized
12 debt expense. DTE Electric’s total long-term debt outstanding on December 31,
13 2022 is detailed on Exhibit A-4, Schedule D2, sponsored by Witness Lepczyk. The
14 weighted long-term debt cost for the historical period was calculated by Witness
15 Lepczyk on Schedule D2 using the net proceeds method for each issue outstanding
16 on December 31, 2022.
17
18 Line 2 of Schedule D1 reflects that the Company had no preferred stock
19 outstanding.
20
21 Line 3 of Schedule D1 shows common shareholders’ equity, which includes
22 common stock outstanding, less expense, plus premium, other paid-in capital,
23 retained earnings and Other Comprehensive Income (OCI) adjustments. The cost
24 of common shareholders’ equity utilized for this exhibit for the historical test period

Line
No.

1 is the 9.90% that was authorized by the Commission in Case No. U-20836 as
2 indicated on Exhibit A-4, Schedule D5, sponsored by Witness Lepczyk.

3
4 The cost of short-term debt, on line 5, is the actual average short-term borrowing
5 cost of the Company in the historical test period. The cost of short-term debt is
6 detailed on Exhibit A-4, Schedule D3, sponsored by Witness Lepczyk.

7
8 The Job Development – ITC amounts on lines 6 (JDITC – Debt) and 7 (JDITC –
9 Equity) of Schedule D1 reflect the corresponding permanent capital percentages for
10 long-term debt and common equity. The associated returns for JDITC – Debt and
11 JDITC – Equity reflect the corresponding permanent capital cost rates for long-
12 term debt and common shareholders' equity, respectively. This calculation
13 complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to
14 assign a rate of return to JDITC at the weighted average cost of permanent capital.

15
16 Net deferred income taxes (line 9) are at zero cost.

17

18 **Section B – Projected Test Period (Twelve Months Ending December 31, 2025)**

19 **Q18. What is the Revenue Deficiency for the projected test period?**

20 A18. Line 11 of Exhibit A-11, Schedule A1, shows absent rate relief, DTE Electric will
21 experience a Total Revenue Deficiency of \$456.4 million for the projected test
22 period, including the return on the Tree Trim Regulatory Asset (line 9) calculated
23 on Exhibit A-11, Schedule A1.1 and the return on the Monroe Regulatory Asset
24 (line 10) calculated on Exhibit A-11, Schedule A1.2. This deficiency is based on
25 the Company's projected financial outlook for the twelve months ending December

Line
No.

1 31, 2025. The revenue deficiency on line 8 is based on the following: a projected
2 rate base of \$22.1 billion, adjusted NOI of \$1,087.1 million, and a projected
3 required rate of return of 5.92%. The total revenue deficiency for the projected test
4 period is presented on line 11 and is calculated by adding the revenue deficiency
5 on line 8 to the return on the Company's Tree Trim Regulatory Asset (line 9) and
6 return on the Company's Monroe Regulatory Asset (line 10).

7

8 The calculation of rate base is detailed in Exhibit A-12, Schedule B1. The NOI for
9 the projected test period is developed on Exhibit A-13, Schedule C1 sponsored by
10 Witness Uzenski. The projected test period required rate of return is set forth in
11 Exhibit A-14, Schedule D1. The components of rate base, NOI, capitalization,
12 required rate of return, and regulatory assets are detailed within my exhibits and
13 schedules, as well as those of Witnesses Uzenski and Lepczyk.

14

15 **Q19. What information is displayed on Exhibit A-12, Schedule B1, entitled**
16 **"Projected Rate Base"?**

17 A19. Exhibit A-12, Schedule B1 shows the detailed composition of the Projected Rate
18 Base (column (d)) for the projected test period on a simple average basis. Line 16,
19 column (d), shows the total projected rate base which consists of net plant and the
20 allowance for working capital. These amounts are carried forward to Exhibit A-
21 11, Schedule A1. This exhibit also provides a comparison of rate base as of
22 December 31, 2022 to the average rate base balances for the projected test period.

23

24 **Q20. What is the Projected Revenue Conversion Factor?**

Line
No.

1 A20. Projected Revenue Conversion Factor is 1.3496 and is used to convert after tax
2 income into pre-tax revenue for the projected test period. Exhibit A-13, Schedule
3 C2 calculates the Revenue Conversion Factor for the projected test period. The
4 derivation of the revenue conversion factor is the same mathematical format as my
5 Exhibit A-3, Schedule C2 from Section A.

6

7 **Q21. What adjustments on Exhibit A-13, Schedule C1.1, “Adjustments to Projected**
8 **Net Operating Income” for the Projected Twelve Months Ending December**
9 **31, 2025 are you supporting?**

10 A21. On this exhibit, which is sponsored by Witness Uzenski, I am supporting the
11 adjustments for:

12 1) Income Tax Effect of Interest (line 14) supported by Exhibit A-13,
13 Schedule C14.

14 2) Interest Synchronization Tax Adjustment (line 15) supported by Exhibit
15 A-13, Schedule C15.

16

17 **Q22. What is the adjustment for “Income Tax Effect of Interest” on Exhibit A-13,**
18 **Schedule C1.1, line 14?**

19 A22. This NOI adjustment on line 14 of Exhibit A-13, Schedule C1.1, is the difference
20 between the forecasted ratemaking amount of interest tax deductions allowed based
21 on the rate case rate of return and the forecasted interest tax deductions included in
22 the projected test period NOI supported by Witness Uzenski. This change in
23 income tax expense is calculated on Exhibit A-13, Schedule C14. The sum of line
24 7 and line 10 of Schedule C14, column (c) reflects an adjustment to decrease

Line
No.

1 income tax expenses resulting in a corresponding increase in NOI as shown on line
2 11 column (c).

3

4 **Q23. What is the “Synchronization Adjustment” on Exhibit A-13, Schedule C1.1,**
5 **line 15?**

6 A23. This NOI adjustment on line 15 of Exhibit A-13, Schedule C1.1 is the rate case
7 Interest Synchronization Adjustment for the projected test period. As I have
8 discussed previously in Section A of my testimony, tax law requires, and prior
9 Commission Orders have allowed, a return on JDITC at the rate of return for
10 permanent capital. This change in the income tax expenses is set forth on Exhibit
11 A-13, Schedule C15. The sum of line 7 and line 10 of Schedule C15, column (c)
12 reflects an adjustment to decrease income tax expenses resulting in a corresponding
13 increase in NOI as shown on line 11 column (c).

14

15 **Q24. What information is reflected on Exhibit A-14, Schedule D1, page 1 of 2,**
16 **entitled “Projected Rate of Return Summary”?**

17 A24. Exhibit A-14, Schedule D1, develops DTE Electric’s projected overall rate of return
18 for the projected test period. The projected December 31, 2025 average balance
19 sheet capital structure amounts, in column (b), are carried over from Exhibit A-12,
20 Schedule B4.1, line 121, columns (e) through (i) and equals the rate base amount
21 on line 16, column (d) of Exhibit A-12, Schedule B1. Schedule D1 calculates DTE
22 Electric’s weighted after-tax projected rate of return on line 10, column (g). This
23 weighted after-tax projected rate of return is carried forward to Exhibit A-11,
24 Schedule A1, line 4 and is used in the determination of the projected revenue
25 deficiency, excluding the return on the Tree Trim Regulatory Asset and the Monroe

Line
No.

1 Regulatory Asset. Schedule D1 also calculates DTE Electric's weighted pre-tax
2 projected rate of return at line 10, column (i). The capital structure excludes any
3 funds on deposit with trustees, and the financing related to regulatory assets and
4 other items eliminated from the historical balance sheet by Witness Uzenski.

5
6 Long-term debt, shown on line 1 of Schedule D1, includes reductions for the net
7 amount of unamortized premium / discount and unamortized debt expense. This
8 balance of long-term debt represents 50.0% of DTE Electric's permanent capital.
9 DTE Electric's projected total long-term debt outstanding as of December 31, 2025
10 is detailed on Exhibit A-14, Schedule D2, sponsored by Witness Lepczyk. The
11 weighted long-term debt cost was calculated by Witness Lepczyk on Schedule D2
12 using the net proceeds method for each issue outstanding as of December 31, 2025
13 including the financing cost of new debt issues.

14
15 Line 2 of Schedule D1 reflects that the Company has no preferred stock
16 outstanding.

17
18 Line 3 of Schedule D1 shows common shareholders' equity, which includes
19 common stock outstanding, less expense, plus premium, paid-in capital, retained
20 earnings and other comprehensive income (OCI) adjustments. This level of
21 common equity represents 50.0% of DTE Electric's permanent capital in the
22 projected test period. The cost of common shareholders' equity utilized for this
23 exhibit is 10.50%, which is supported by DTE Electric Witness Dr. Villadsen in
24 her testimony.

25

Line
No.

1 The cost of short-term debt, on line 5, is the forecasted average short-term
2 borrowing cost of the Company for the projected test period supported by Witness
3 Lepczyk on Exhibit A-14, Schedule D3.

4
5 The Job Development – ITC amounts on line 6 (JDITC – Debt) and line 7 (JDITC
6 – Equity) of Schedule D1 reflect the corresponding permanent capital percentages
7 for long-term debt and common equity. The associated returns for JDITC–Debt
8 and JDITC–Equity reflect the corresponding permanent capital cost rates for long-
9 term debt and common shareholders’ equity, respectively. This calculation
10 complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to
11 assign a rate of return to JDITC at the weighted average cost of permanent capital.

12
13 Average projected deferred income taxes (line 9) are at zero cost of capital.

14
15 **Q25. What information is reflected on Exhibit A-14, Schedule D1, page 2 of 2,**
16 **entitled “Projected Rate of Return - Base Rate Request and Monroe**
17 **Regulatory Asset”?**

18 A25. The Commission approved a settlement agreement in the Company’s Integrated
19 Resource Plan (IRP) in Case No. U-21193 on July 26, 2023. The settlement
20 stipulates that “[t]he parties further agree that the remaining [net book value] of
21 Monroe as of December 31, 2024, will be recovered through a regulatory asset with
22 a return on equity (ROE) that will be set at 9.0% amortized over 15 years beginning
23 upon the issuance of an order in the company’s next rate case.” Exhibit A-14,
24 Schedule D1, page 2 of 2, performs the calculation of the rate of return to be applied
25 to the Monroe regulatory asset.

Line
No.

1

2

Lines 1 through 7 are a restatement of Exhibit A-14, Schedule D1, page 1 of 2, summarizing the percent of capitalization, cost rate, pre-tax and after-tax rates of return. Lines 8 through 14 recalculate the pre-tax and after-tax rates of return utilizing a 9.0% return on equity for Common Shareholders' Equity and the equity component of the Job Development – ITC. The pre-tax rate of return calculated on line 14, column (f), is utilized on Exhibit A-11, Schedule A1.2 to determine the return on the Monroe Regulatory Asset.

9

10 **Return On DTE Electric's Tree Trim Surge Proposal**

11 **Q26. What information is provided on Exhibit A-11, Schedule A1.1 entitled "Tree**
12 **Trim Regulatory Asset – Return On"?**

13 A26. Exhibit A-11, Schedule A1.1, identifies the return on the Tree Trim Regulatory
14 Asset for the projected test period relating to the Tree Trim Surge proposal as
15 discussed by Company Witness Steudle. Line 2 is the average balance for the Tree
16 Trim Regulatory Asset as calculated on lines 8 through 16, based on the
17 expenditures supported by Witness Steudle on Exhibit A-13, Schedule C5.6.1 and
18 a reduction to the asset balance of \$156.9 million for amounts approved to be
19 securitized in Case No. U-21015 (page 91 of Order dated June 23, 2021). The
20 Return on Tree Trim, shown on line 6 is based on the Average Net Rate Base on
21 line 4 multiplied by the pre-tax Authorized Rate of Return on Permanent Capital
22 on line 5. The pre-tax Authorized Rate of Return on Permanent Capital is
23 calculated on Exhibit-14, Schedule D1 and was utilized as instructed by Company
24 Witness Lepczyk.

25

Line
No.

1 **Return On DTE Electric’s Monroe Regulatory Asset**

2 **Q27. What information is provided on Exhibit A-11, Schedule A1.2 entitled**
3 **“Monroe Regulatory Asset – Return On”?**

4 A27. Exhibit A-11, Schedule A1.2, identifies the return on the Monroe Regulatory Asset
5 for the projected test period relating to the balance of Monroe Power Plant that is
6 not being securitized and is to be recovered as a regulatory asset over fifteen years
7 as discussed by Company Witness Uzenski. Line 2 is the average balance for the
8 Monroe Regulatory Asset as calculated on Exhibit A-12, Schedule B4.4 and
9 supported by Witness Uzenski. The Return on Monroe Regulatory Asset, shown
10 on line 4 is based on the average balance from line 2 multiplied by the Pre-tax
11 Weighted Average Cost of Capital on line 3 as calculated on Exhibit A-14,
12 Schedule D1, page 2.

13

14 **Revenue Requirement for DTE Electric’s Infrastructure Recovery Mechanism**

15 **Q28. What information is provided on Exhibit A-33, Schedule X4 entitled**
16 **“Infrastructure Recovery Mechanism – Incremental Revenue Requirement –**
17 **Distribution Operations”?**

18 A28. Exhibit A-33, Schedule X4, page 1, identifies the annual incremental Revenue
19 Requirements for DTE Electric’s IRM program years 2024¹, 2025, 2026 and 2027
20 related to the Distribution Operations plant in service discussed by Company
21 Witness Foley. The Revenue Requirement components consist of Return on Net
22 Rate Base, Depreciation, and Property Taxes. Lines 19 through 22, on page 1 of
23 Exhibit A-33, Schedule X4 show the underlying Revenue Requirement amounts
24 for years 2024¹ through 2027 that are used by Company Witness Maroun to derive

¹ The 13 months ended December 31, 2024

Line
No.

1 the IRM Cost of Service by Voltage Class for the respective years. The revenue
2 requirement calculation for years 2024¹ and 2025 within this exhibit utilize the
3 same plant in service amounts, rate of return, depreciation rates, and property tax
4 millage rates as those approved for the IRM by the Commission for DTE Electric
5 Rate Case No. U-21297. As such, the calculated revenue requirements for 2024¹
6 and 2025 are identical to what was ordered within DTE Electric Rate Case No. U-
7 21297.

8

9 Lines 3 through 8 represent the Distribution Operations plant in service amounts
10 summarized by Witness Foley on Exhibit A-33, Schedule X1. Lines 12 through
11 16, calculate the Average Net Rate Base. This incremental "Net Rate Base" reflects
12 traditional Rate Base (Net Utility Plant) less Accumulated Deferred Income Taxes.
13 The Return on Net Rate Base, shown on line 19, is based on the Average Net Rate
14 Base multiplied by the pre-tax rate of return. Since rate base for the IRM is shown
15 net of deferred taxes, the weighted cost of permanent capital is used. Depreciation,
16 line 20, is based on the half year convention. The line 21 Property Taxes are derived
17 on page 2 of this exhibit.

18

19 **Q29. What is the basis for the pre-tax rate of return utilized?**

20 A29. The pre-tax rate of return is DTE Electric's permanent capital projected weighted
21 cost rates from Exhibit A-14, Schedule D-1, grossed up by the appropriate pre-tax
22 multiplier discussed previously in my testimony.

23

24 **Q30. What is the basis for the depreciation rate utilized on Exhibit A-33, Schedule**
25 **X4?**

Line
No.

1 A30. The depreciation rate reflects the composite depreciation rate for distribution plant,
2 as supported by Witness Uzenski on Exhibit A-13, Schedule C6, page 2, line 9,
3 column (h). The depreciation rate is applied to the projected plant in service for the
4 three years shown on Exhibit A-33, Schedule X4.

5

6 **Q31. What is the purpose of page 2 of Exhibit A-33, Schedule X4?**

7 A31. Page 2 of Exhibit A-33, Schedule X4 shows the calculations of the accumulated
8 deferred tax expense used in the derivation of Net Rate Base and the property taxes
9 included in the revenue requirement, shown on page 1 of Exhibit A-33, Schedule
10 X4.

11

12 **Q32. How are property taxes calculated on page 2 of Exhibit A-33, Schedule X4?**

13 A32. Property tax expense for the proposed IRM assets is applicable to both in-service
14 and CWIP assets. Lines 19 through 30 calculate the applicable taxable value and
15 property tax expense for plant in service assets. The property tax expense for plant
16 in service assets is calculated by multiplying the taxable value by the millage rate,
17 which is supported by Witness Wisniewski. In addition, lines 32 through 47
18 calculate the applicable taxable value and property tax expense for CWIP assets.
19 The property tax expenses for CWIP assets are also calculated by multiplying the
20 taxable value by the millage rate, which is supported by Witness Wisniewski.

21

22 **Q33. How is the Company proposing to reconcile actual investment to the**
23 **investment proposed for IRM treatment in the instant case?**

24 A33. The Company's proposed reconciliation is more fully described by Witness Foley.
25 At a high level, the Company is proposing that after the conclusion of each calendar

Line
No.

1 year, the Company would calculate a revenue requirement based on actual
2 investment and plant in service for the previous year. This actual revenue
3 requirement would be compared to the revenue requirement ordered by the
4 Commission and calculated in a manner consistent with Exhibit A-33, Schedule
5 X4. If the actual revenue requirement is less than the ordered revenue requirement,
6 it would represent an over-recovery to be returned to customers. Importantly, the
7 amount of capital that can be placed into service for each program under the IRM
8 construct is capped at the amounts proposed by Company Witness Foley and
9 captured in my Exhibit A-33, Schedule X4 (page 1, lines 3-8). If the Company
10 elects to invest and place into service capital above the amounts proposed in the
11 instant case, it can request recovery of that additional capital in a future rate case.

12

13 **Q34. Have you prepared an example to illustrate this?**

14 A34. Yes. Exhibit A-33, Schedule X5 entitled “Infrastructure Recovery Mechanism –
15 Incremental Revenue Requirement – Distribution Operations – Example of \$1.0
16 MM Under Investment” utilizes the Company’s filed IRM revenue requirement
17 methodology and inputs to calculate the revenue requirement of a \$1 million of
18 lower plant in service recorded in the program in the first year of the IRM
19 mechanism.

20

21 As can be seen on of Exhibit A-33, Schedule X5 (page 1, line 16), in this example
22 \$1 million less of in-service capital would result in an actual revenue requirement
23 \$65 thousand less than the revenue requirement calculated in Exhibit A-33,
24 Schedule X4 (page 1, line 22). As proposed by Company Witness Foley, in this

Line
No.

1 example the Company would record a \$65 thousand Regulatory Liability to be
2 returned to customers in a future rate case with interest.

3

4 **Q35. What is the purpose of page 2 of Exhibit A-33, Schedule X5?**

5 A35. Page 2 of Exhibit A-33, Schedule X5 shows the calculations of the accumulated
6 deferred tax expense used in the derivation of Net Rate Base shown on page 1 of
7 Exhibit A-33, Schedule X5.

8

9 **Summary**

10 **Q36. What are you proposing based on your testimony in this proceeding?**

11 A36. I am proposing that the Commission issue findings consistent with the matters
12 presented in my testimony. Specifically, as shown in Section B, on Exhibit A-11,
13 Schedule A1, that DTE Electric's revenue deficiency for the projected test period
14 is \$456.4.

15

16 **Q37. Does this complete your direct testimony?**

17 A37. Yes, it does.

1 JUDGE WALLACE: O.K., please proceed.

2 MS. REITZEL: Thank you, your Honor.

3 Next, we would move to bind into the record the Direct
4 Testimony of Sherri L. Wisniewski, which consists of a
5 cover sheet and 16 pages of questions and answers, and
6 for the admission of ten direct exhibits and schedules,
7 designated as Exhibit A-3 Schedule C7, Exhibit A-3
8 Schedule C8, Exhibit A-3 Schedule C9, Exhibit A-3
9 Schedule C10, Exhibit A-13 Schedule C7, Exhibit A-13
10 Schedule C7.1, Exhibit A-13 Schedule C8, Exhibit A-13
11 Schedule C8.1, Exhibit A-13 Schedule C9, and Exhibit A-13
12 Schedule C10. Ms. Wisniewski also had rebuttal
13 testimony, consisting of a cover sheet and six pages of
14 questions and answers, with no rebuttal exhibits.

15 JUDGE WALLACE: Thank you. Is there any
16 objection to binding in the direct and rebuttal testimony
17 of Ms. Wisniewski?

18 Hearing none, the testimony is bound in.

19 Is there any objection to any of the
20 exhibits or associated schedules sponsored by
21 Ms. Wisniewski?

22 All right. We'll admit those shortly.

23 (Testimony bound in.)

24 - - -

25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHERRI L. WISNIEWSKI

Line
No.

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

2 A1. My name is Sherri L. Wisniewski (she/her/hers). My business address is: One
3 Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
4 Services, LLC.

5

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

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

8

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

10 A3. I earned a Bachelor of Business Administration from Western Michigan University
11 in 1993 and a Master of Business Administration from The University of Michigan
12 in 1998.

13

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

15 A4. I have been with DTE Energy in the Tax Department since 1996 and became
16 Director of Tax Operations in July 2016 and am currently responsible for tax
17 accounting, tax forecasting, and regulatory tax.

18

19 **Q5. Have you previously sponsored testimony before the Michigan Public Service**
20 **Commission (MPSC or Commission)?**

21 A5. I have sponsored testimony in the following cases:

22 U-18232 DTE Electric REP Amended Plan

23 U-18232 DTE Electric 2020 Amended REP Plan - March 2020

24 U-18255 DTE Electric Rate Case

25 U-18999 DTE Gas Rate Case

<u>Line No.</u>		
1	U-20029	DTE Electric EWR 2017 Reconciliation
2	U-20051	DTE Electric 2017 TRM Reconciliation
3	U-20105	DTE Electric Credit A Rate Case
4	U-20106	DTE Gas Credit A Rate Case
5	U-20162	DTE Electric Rate Case
6	U-20172	DTE Electric REP 2017 Reconciliation
7	U-20298	DTE Gas Calculation C
8	U-20484	DTE Electric REP 2018 Reconciliation
9	U-20561	DTE Electric Rate Case
10	U-20642	DTE Gas Rate Case
11	U-20723	DTE Electric REP 2019 Reconciliation
12	U-20835	DTE Electric Company for Accounting Approval to Accelerate
13		Amortization of the Tax Cuts and Job Act Regulatory Liability for
14		Non-Plant Related Accumulated Deferred Income Taxes
15	U-20851	DTE Electric 2020 Amended REP Plan
16	U-20940	DTE Gas Rate Case
17	U-21010	DTE Electric 2020 REP Reconciliation
18	U-20836	DTE Electric Rate Case
19	U-21285	DTE Electric 2022 Amended REP Plan
20	U-21198	DTE Electric 2021 REP Reconciliation
21	U-21291	DTE Gas Rate Case
22	U-21297	DTE Electric Rate Case
23	U-21353	DTE Electric REP 2022 Reconciliation
24	U-21361	DTE Electric 2023 Amended REP Plan

Line
No.

1 **Purpose of Testimony**

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

3 A6. The purpose of my testimony is to discuss and support the reasonableness of DTE
4 Electric's Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT),
5 municipal (city) income tax, property tax and other general taxes for the 2022
6 calendar year historical period and the twelve months ending December 31, 2025,
7 projected test period.

8

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

10 A7. Yes. I am supporting the following exhibits:

11	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
12	A-3	C7	Historical General Taxes
13	A-3	C8	Historical Federal Income Taxes
14	A-3	C9	Historical State and Local Income Taxes
15	A-3	C10	Historical Other Taxes
16	A-13	C7	Projected General Taxes – Other
17	A-13	C7.1	Projected General Taxes – Property
18	A-13	C8	Projected Federal Income Tax
19	A-13	C8.1	Projected TCJA Regulatory Liability
20	A-13	C9	Projected State Income Tax
21	A-13	C10	Projected Local Income Tax

22

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

24 A8. Yes, they were.

25

Line
No.

1 **Q9. What income tax rates are you assuming in this instant case?**

2 A9. For all periods in this case, I am assuming a FIT rate of 21% and a MCIT rate of
3 5.88% (6% statutory rate at 98% apportionment) and municipal income tax of
4 0.33%. The municipal income tax rate represents a composite rate including all
5 cities in which DTE Electric has a municipal income tax obligation.

6

7 **HISTORIC PERIOD**

8 **Q10. How was the 2022 historical period property tax expense derived for the rate**
9 **case?**

10 A10. The 2022 historical period property tax expense in Exhibit A-3, Schedule C7, line
11 1, column (c) and Exhibit A-13, Schedule C7, line 1, column (b) of \$286.6 million
12 represents property tax expense on all DTE Electric property. Exhibit A-13,
13 Schedule C7, line 1, shows the walk from the \$286.6 million in column (b) to
14 \$265.9 million adjusted historical property tax expense in column (e). Adjusted
15 historical property tax expense of \$265.9 million was applicable to property
16 reflected in DTE Electric's general rate case filings (referred to hereafter as general
17 rate case property), which includes \$1.0 million for Midwest Energy Resources
18 Company (MERC) and excludes \$21.6 million applicable to Renewable Energy
19 Plan (REP) property. Property tax *expense* refers to the amount of property taxes
20 deducted for book purposes. Property tax *liability* refers to the amount of property
21 taxes payable to local governments. Because the Company expenses its property
22 tax liability over a two-year period,¹ one will see a difference annually between
23 liability and expense.

¹ The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

Line
No.

1

2 **Q11. How was the 2022 historical period payroll tax expense derived?**

3 A11. The 2022 historical period payroll tax expense in Exhibit A-3, Schedule C7, line 2,
4 column (c) of \$36.7 million consists of Social Security and Medicare taxes referred
5 to collectively as “FICA” as well as federal and Michigan state unemployment
6 taxes. These payroll taxes for the historic period are before rate case and
7 normalization adjustments and are derived from the Company’s payroll system
8 based on individual employees’ wages up to a maximum taxable limit times a
9 prescribed rate.

10

11 **Q12. What are the Other General Taxes reflected on Exhibit A-3, Schedule C7?**

12 A12. In addition to payroll taxes of \$36.7 million, Public Utility Assessment fees of
13 \$12.9 million and Use Tax and Other tax totaling \$0.2 million are included in the
14 Total Other General Taxes. Total Other General Taxes of \$49.8 million as shown
15 on Exhibit A-3, Schedule C7 are for DTE Electric as a whole. Total 2022 historical
16 other general tax expense after rate case and normalization adjustments is \$49.2
17 million as shown on Exhibit A-3, Schedule C1.1, which is supported by Company
18 Witness Uzenski.

19

20 **Q13. Is there anything unique or unusual regarding 2022 historical period income**
21 **tax expense?**

22 A13. The 2022 historical period income tax expense, which includes FIT expense, MCIT
23 expense, and municipal income tax expense, is calculated in the same general
24 manner as it was in Case No. U-21297. Income tax expense includes both current
25 income taxes (taxes payable currently) and deferred taxes (taxes payable in the

Line
No.

1 future). Historical income tax expense amounts are shown on Exhibit A-3,
2 Schedules C8 and C9.

3
4 The 2022 historical period FIT expense includes additional amortization of the Tax
5 Cuts and Jobs Act (TCJA) regulatory liability consistent with the order received in
6 U-20835, which allowed the November 30, 2021, balance of the non-plant
7 component of the TCJA regulatory liability of \$103 million to be fully amortized
8 from December 2021 thru November 2022.

9
10 The income tax expense amounts shown on Exhibit A-3, Schedules C8 and C9
11 reflect income tax expense for DTE Electric as a whole. These income tax expense
12 amounts are adjusted for rate case, normalization, and other adjustments in Exhibit
13 A-3, Schedule C1.1, which is supported by Company Witness Uzenski. Total 2022
14 historical year income tax expense after the adjustments is \$94.1 million.

15
16 **Q14. What does the balance sheet reclass for Accumulated Deferred Income Taxes**
17 **and Accumulated Deferred Investment Tax Credit on Witness Uzenski's**
18 **Exhibit A-2, Schedule B6.1, column (e) represent?**

19 A14. There are two adjustments that are reflected in Witness Uzenski's exhibit that are
20 reclassified to Accumulated Deferred Income Tax Liability.

21
22 The first adjustment is to reclassify the Accumulated Deferred Income Tax Asset
23 on Exhibit A-2, Schedule B6.1, pages 1 of 2, line 67 to Accumulated Deferred
24 Income Tax Liabilities, line 113, for proper balance sheet presentation. This is
25 consistent with prior rate case filings.

Line
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1

2

The second adjustment is to reclassify a portion of the regulatory liability on line 114 to accumulated deferred income taxes on line 113. This represents Investment Tax Credits (ITCs) DTE Electric generated but had not yet utilized as of 12/31/2022. Because these ITCs will be utilized in a future year, a deferred tax asset was recorded and is included in line 113. Because DTE Electric has not recognized the cash benefit of the ITCs, the regulatory liability for these credits must be reclassified to eliminate any impact it would have on the cost of capital. This is consistent with prior rate case filings.

3

4

5

6

7

8

9

10

11 **FORECAST PERIOD**

12 **Q15. What subjects will your testimony and exhibits cover related to the twelve**
13 **months ending December 31, 2025, projected test period?**

14 A15. I am supporting the FIT, MCIT, Municipal Income Tax, Property Tax and Other
15 general taxes shown on Exhibit A-13, Schedules C7 through C10. These schedules,
16 which are primarily based on forecasted amounts sponsored by other Company
17 witnesses, are used to derive the various tax expense amounts for the projected test
18 period.

19

20 **Q16. How are Michigan property taxes assessed?**

21 A16. Michigan property tax is imposed annually by local governments on the taxable
22 value of all real and tangible personal property, including construction work in
23 progress (CWIP), unless specifically exempted by law. The liability for any given
24 year is based on the taxable value of property on December 31 of the previous year,

Line
No.

1 which is referred to as the assessment date. For example, the 2022 liability is based
2 on the taxable value of property on December 31, 2021.

3

4 The taxable value is calculated by multiplying the true cash value (see below) of
5 the property by 50%. The liability is then derived by multiplying the taxable value
6 by the millage rate (can also be referred to as a tax rate). Millage rates vary
7 throughout the state and represent the aggregate levies for all taxing units (county,
8 township, city, village, and school districts) within which the property is located.
9 The liability is billed in two parts, with one bill generally received in December
10 (referred to as the winter bill) and the other bill generally received in June (referred
11 to as the summer bill). The billing dates and allocation of the liability between the
12 billing dates is driven by the fiscal year of the taxing jurisdiction and, therefore,
13 will vary by jurisdiction.

14

15 **Q17. In the calculation of the property tax liability, what is ‘true cash value’ and**
16 **how is it calculated?**

17 A17. True cash value is meant to represent fair market value and is determined by local
18 assessors who apply guidelines set forth by the State Tax Commission (STC),
19 which supervises the valuation and assessment of property. To determine true cash
20 value, assessors will utilize multiplier tables established by the STC. The tables
21 are designed to mimic the expected life cycle of the property. STC multipliers will
22 change over the life of the property to represent the change in value over time driven
23 by factors such as typical usage patterns and obsolescence. An STC multiplier
24 enables an assessor to determine true cash value by multiplying the appropriate

Line
No.

1 STC multiplier by the historical cost of the property instead of performing a
2 comprehensive market value analysis every year.

3

4 **Q18. When does the Company know its property tax liability for any given year?**

5 A18. The Company files property tax returns (referred to as renditions) in late February
6 and early March to report property on hand as of the assessment date (December
7 31). A separate rendition is filed with each assessor in each location where property
8 is owned. The liability is still an estimate at that time and will continue to be
9 updated as the Company receives assessments from local assessors in March and
10 April and bills in June and December.

11

12 **Q19. How are the 2022 and 2023 property tax liabilities reflected in your exhibits?**

13 A19. Exhibit A-13, Schedule C7.1 shows the 2022 and 2023 property tax liabilities in
14 column (c) on lines 3 and 4, respectively.

15

16 The 2022 tax liability² of \$265.4 million (line 3, column (c)) represents the actual
17 property taxes assessed and paid on all general rate case property on hand as of
18 December 31, 2021.

19

20 The 2023 tax liability of \$281.4 million (line 4, column (c)) represents the estimated
21 property taxes that will be assessed and paid on all general rate case property on

² Property tax *liability* refers to the amount of property taxes payable to local governments, whereas property tax *expense* refers to the amount of property taxes deducted for book purposes. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. The 2022 Property tax expense as stated in the historical section of my testimony was \$286.6. million.

Line
No.

1 hand as of December 31, 2022, based primarily on assessments received from local
2 assessors.

3

4 **Q20. What is the projected 2024 Property tax liability?**

5 A20. Exhibit A-13, Schedule C7.1, shows the projected 2024 property tax liability of
6 \$313.8 million on line 54, column (c).

7

8 **Q21. How was the projected 2024 Property Tax liability on Exhibit A-13, Schedule**
9 **C7.1, line 54 calculated?**

10 A21. This represents the projected property taxes that will be assessed and paid on all
11 general rate case property projected to be on hand as of December 31, 2023. This
12 is based on the 2023 estimated tax liability of \$281.4 million (line 52, column (c))
13 plus the increase in liability projected for 2024 of \$32.4 million (line 53, column
14 (c)). The increase in liability projected for 2024 is calculated in column (c) on lines
15 25 through 50. The taxable value of 2023 net additions is estimated to be \$618.7
16 million (line 35, column (c)), driven primarily by 2023 capital additions less
17 retirements and reductions and nontaxable expenditures. It also takes into
18 consideration the change in CWIP and applies first year STC multipliers to both
19 the net additions and the change in CWIP. Annual inflation of real property on
20 hand as of December 31, 2022, is estimated to be an increase in taxable value of
21 \$33.5 million (line 41, column (c)). Annual obsolescence of personal property on
22 hand as of December 31, 2022, is estimated to be a reduction in taxable value of
23 \$73.6 million (line 47, column (c)). The estimated composite millage rate of 56.0
24 is then applied to the net increase in taxable value of \$578.5 million (line 48,
25 column (c)).

Line
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1

2

Capital additions and retirements for all periods presented are supported by

3

Company Witnesses sponsoring Schedules B5 through B5.10 of Exhibit A-12.

4

5

Q22. What is the projected 2025 Property tax liability?

6

A22. Exhibit A-13, Schedule C7.1, shows the projected 2025 property tax liability of

7

\$349.7 million on line 56, column (e).

8

9

Q23. How was the projected 2025 Property Tax liability on Exhibit A-13, Schedule

10

C7.1, line 56 calculated?

11

A23. This represents the projected property taxes that will be assessed and paid on all

12

general rate case property projected to be on hand at December 31, 2024. This is

13

based on the 2024 projected tax liability of \$313.8 million (line 54, column (e))

14

plus the increase in liability projected for 2025 of \$35.9 million (line 55, column

15

(e)). The increase in liability projected for 2025 is calculated in column (e) on lines

16

25 through 50. The taxable value of 2024 net additions is estimated to be \$679.7

17

million (line 35, column (e)), driven primarily by 2024 capital additions less

18

retirements and reductions and nontaxable expenditures. It also takes into

19

consideration the change in CWIP and applies first year STC multipliers to both

20

the net additions and the change in CWIP. Annual inflation of real property on

21

hand as of December 31, 2023, is estimated to be an increase in taxable value of

22

\$35.2 million (line 41, column (e)). Annual obsolescence of personal property on

23

hand as of December 31, 2023, is estimated to be a reduction in taxable value of

24

\$72.5 million (line 47, column (e)). The estimated composite millage rate of 56.0

Line
No.

1 is then applied to the net increase in taxable value of \$642.4 million (line 48,
2 column (e)).

3

4 **Q24. What is the amount of property tax expense the Company is seeking recovery**
5 **of, and how is it calculated?**

6 A24. The Company is seeking recovery of property tax expense of \$328.8 million for the
7 projected test period (January 1, 2025, through December 31, 2025), which is
8 included in Exhibit A-13, Schedule C1, line 6, column (e) supported by Witness
9 Uzenski. Property tax *expense* refers to the amount of property taxes deducted for
10 book purposes. Property tax *liability* refers to the amount of property taxes payable
11 to local governments. The Company expenses its property tax liability over a two-
12 year period, with the liability of each year being expensed 39% the current year and
13 61% the subsequent year. This two-year allocation methodology has been used for
14 many years and is based, generally, on the fiscal years of the various taxing
15 jurisdictions to which property taxes are paid.

16

17 The 2024 calendar year property tax expense of \$294.9 million (Exhibit A-13,
18 Schedule C7.1, line 13, column (e)) represents 61% of the 2023 property tax
19 liability and 39% of the 2024 property tax liability. Due to the two-year expensing
20 methodology, the increase of \$22.3 million over the 2023 property tax expense of
21 \$272.6 million was driven by the changes in both the 2023 estimated tax liability
22 and the 2024 projected tax liability.

23

24 The 2025 calendar year property tax expense of \$328.8 million represents 61% of
25 the 2024 projected property tax liability and 39% of the 2025 projected property

Line
No.

1 tax liability. Due to the two-year expensing methodology, the increase of \$33.9
2 million over the 2024 property tax expense of \$294.9 million is driven by the
3 increases in both the 2024 and the 2025 projected tax liabilities.

4

5 Projected test period property tax expense is equal to the 2025 calendar year
6 property tax expense of \$328.8 million.

7

8 **Q25. What is the Other Tax Expense portion of DTE Electric's operating expense?**

9 A25. DTE Electric is seeking recovery of Other Tax expense for the projected test period
10 of \$53.2 million. Other Tax expense consists of payroll taxes (\$39.3 million),
11 Public Utility Assessment fees (\$13.6 million), and miscellaneous other taxes (\$0.2
12 million, primarily use taxes) as shown on Exhibit A-13, Schedule C7 on lines 2
13 through 5 in column (j).

14

15 **Q26. How did you forecast the Other Tax Expense?**

16 A26. DTE Electric's O&M forecast is driven primarily by inflation increases. Because
17 payroll taxes generally follow O&M expense, it has been forecasted by
18 incrementing the historic period actual amounts by DTE Electric's assumed annual
19 wage inflation rate. Exhibit A-13, Schedule C5.15, which is supported by Witness
20 Uzenski, lists inflation rates for the interim forecast and projected test periods. DTE
21 Electric's forecast for Public Utility Assessment fees was adjusted to account for
22 an increase in contributions to the Utility Customer Representation Fund expected
23 for DTE Electric as a result of Public Act 231 of 2023. Other miscellaneous other
24 taxes were held to their 2022 historical amounts.

25

Line
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1 **Q27. How much total income tax expense is the Company seeking recovery of?**

2 A27. DTE Electric is seeking recovery of total income tax expense of \$169.2 million.
3 This is comprised of FIT expense of \$107.8 million and MCIT and municipal
4 income tax expense of \$61.4 million.
5

6 **Q28. How was the FIT Expense portion of DTE Electric's operating expense**
7 **developed?**

8 A28. Exhibit A-13, Schedule C8, line 53 shows DTE Electric's FIT expense for the
9 projected test period is \$107.8 million. Exhibit A-13, Schedule C8, illustrates that
10 FIT expense is comprised of current FIT expense (line 5) and deferred FIT expense
11 (line 6). Current FIT expense is \$12.5 million, which is calculated based on taxable
12 income as shown on line 8 through 44. Deferred FIT expense is shown on lines
13 45 thru 52 and is based on book versus tax temporary differences and the net
14 operating loss (NOL) carryforward (line 45), annual amortization of several
15 Deferred Debits and Credits (Medicare Part D Subsidy, FAS 109, Investment Tax
16 Credit (ITC), and the Tax Cuts and Jobs Act (TCJA) Regulatory Liability (lines 46
17 - 49), R&D Tax Credit carryforward (line 50) and utilization of tax credits
18 generated in prior years (line 51).
19

20 **Q29. Is the overall methodology for amortizing the TCJA regulatory liability, as**
21 **reflected in Exhibit A-13, Schedule C8.1, consistent with the order received in**
22 **U-21297?**

23 A29. Yes. Amortization for the projected test period January 1, 2025 through December
24 31, 2025, reduces tax expense by \$50.2 million as reflected in Exhibit A-13,
25 Schedule C8, line 49.

Line
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1

2 **Q30. How was the MCIT expense portion of DTE Electric's operating expense**
3 **developed?**

4 A30. Line 14 of Exhibit A-13, Schedule C9, shows DTE Electric's MCIT expense for
5 the projected test period is \$58.4 million. Exhibit A-13, Schedule C9, illustrates
6 that MCIT expense is comprised of current MCIT and deferred MCIT. Current
7 MCIT is zero due to a MCIT NOL carryforward being utilized in the projected test
8 period, as reflected on Exhibit A-13, Schedule C9, line 7. Deferred MCIT is based
9 on book versus tax temporary differences, NOL carryforward, and the annual
10 amortization of the MCIT Deferred Debit. The amortization of the MCIT Deferred
11 Debit includes the impacts of the Michigan tax law changes of 2008 and 2012 and
12 the re-measurement of MCIT deferred tax balances at December 31, 2018.

13

14 **Q31. How was the Municipal Income Tax Expense portion of DTE Electric's**
15 **operating expense developed?**

16 A31. Line 11 of Exhibit A-13, Schedule C10, shows DTE Electric's municipal income
17 tax for the projected test period is \$3.0 million. Exhibit A-13, Schedule C10,
18 illustrates that municipal income tax expense is comprised of current and deferred
19 municipal income tax expenses. Current municipal income tax is \$0.3 million due
20 to a municipal NOL being utilized in the projected test period, as reflected on
21 Exhibit A-13, Schedule C10, line 4. Deferred municipal income tax is based on
22 book versus tax temporary differences, NOL carryforward, and the annual
23 amortization of the City of Detroit Deferred Debit that arose from the City of
24 Detroit tax law change of 2012.

25

Line
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1 **Q32. Does this complete your direct testimony?**

2 **A32. Yes, it does.**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHERRI L. WISNIEWSKI

Line
No.

1 **Q1. Are you the same Sherri L. Wisniewski who previously offered testimony in**
2 **this proceeding?**

3 A1. Yes, I am.

4

5 **Q2. What is the purpose of your rebuttal testimony?**

6 A2. The purpose of my testimony is to:

- 7 • Rebut the property tax expense adjustment proposed by Attorney General
- 8 (AG) Witness Coppola. If capital disallowances are ordered by the
- 9 Commission, the methodology used by Witness Coppola to adjust property
- 10 tax expense is inaccurate.
- 11 • Rebut the property tax expense adjustment proposed by Association of
- 12 Businesses Advocating Tariff Equity (ABATE) Witness York. If capital
- 13 disallowances are ordered by the Commission, the methodology used by
- 14 Witness York to adjust property tax expense is inaccurate.
- 15 • Propose a methodology for adjusting property tax expense if capital
- 16 disallowances are ordered by the Commission.

17

18 The purpose of my testimony is limited to discussion of the methodology used to

19 calculate a property tax adjustment if the Commission orders a capital

20 disallowance. The purpose of my testimony is not to discuss the reasonableness of

21 any capital adjustments proposed by the Staff or any intervenors, as that is being

22 addressed in the rebuttal testimony of other Company witnesses. The absence of a

23 discussion of other matters in my rebuttal testimony should not be taken as an

24 indication that I agree with other aspects of any Staff or intervenor testimony.

Line
No.

1 **Q3. Are you sponsoring any rebuttal exhibits?**

2 A3. No.

3

4 **Rebuttal of the Property Tax Expense adjustment proposed by AG Witness Coppola**

5 **Q4. What property tax expense adjustment did Witness Coppola propose?**

6 A4. On page 125, lines 4 through 10 of Witness Coppola's testimony, Witness Coppola
7 is recommending a reduction in property tax expense for the projected test year of
8 \$12.3 million as calculated on Exhibit AG-18. The methodology Witness Coppola
9 is using to calculate this adjustment is to take the AG's proposed capital expenditure
10 reductions for 2024 and prior years, excluding Customer Service/IT, and multiply
11 this by 96%, 50%, and a millage rate of 56.0.

12

13 **Q5. Do you agree with the methodology Witness Coppola is using to calculate the**
14 **property tax expense adjustment on proposed capital expenditure reductions?**

15 A5. No. This methodology fails to consider the following aspects of the property tax
16 expense calculation:

- 17 • Not all capital expenditures are subject to property tax in the same way. Plant
18 additions and changes in construction work in progress (CWIP) are taxed
19 differently from each other, and removal costs are not subject to property tax
20 at all. Witness Coppola's methodology does not distinguish those components
21 of the AG's proposed capital expenditure reductions so that property taxes on
22 each component can be calculated correctly.
- 23 • The Company treated capital expenditures related to steam power generation
24 and nuclear generation as nontaxable expenditures in this filing. Witness
25 Coppola's methodology does not exclude these components of the proposed

Line
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1 capital expenditure reductions from the calculation of the property tax
2 expense adjustment.

3 • As discussed in my direct testimony (page 12, lines 6 through 7), the
4 Company is seeking recovery of property tax expense of \$328.8 million for
5 the projected test period (January 1, 2025, through December 31, 2025).
6 Property tax expense refers to the amount of property taxes deducted for book
7 purposes, whereas property tax liability refers to the amount of property taxes
8 payable to local governments. As discussed in my direct testimony (page 12,
9 lines 17 through 22), the Company expenses its property tax liability over a
10 two-year period, with the total liability of each year being expensed 39% the
11 current year and 61% the subsequent year. Therefore, if there is a change in
12 the property tax liability in any given year, property tax expense for that same
13 year will change by only 39% of that change in the property tax liability. For
14 example, if the 2025 property tax liability is reduced by \$100,000, 2025
15 property tax expense is reduced by only \$39,000 (39% of \$100,000). Witness
16 Coppola's methodology ignores this step of expensing the property tax
17 liability over a two-year period.

18
19 By not taking these factors into consideration, Witness Coppola's methodology
20 results in a significant overstatement of the property tax expense adjustment on
21 proposed capital expenditure reductions.

22
23 **Rebuttal of the Property Tax Expense adjustment proposed by ABATE Witness York**

24 **Q6. What property tax expense adjustment did Witness York propose?**

25 A6. On page 32 of Witness York's testimony, Witness York is recommending a
26 reduction in property tax expense for the projected test year of \$6.1 million, as

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1 stated in TABLE JAY-4, line 3. Nowhere in her testimony or exhibits does Witness
2 York explain why she is adjusting property tax expense or the methodology she is
3 using to calculate the adjustment. However, Witness York's workpaper JAY WP-
4 3 , tab Table JAY-4, row 35, does include a formula showing the proposed property
5 tax adjustment of \$6.1 million is calculated by dividing ABATE's proposed capital
6 expenditure adjustments by 2 and multiplying this by 1.5%.

7
8 **Q7. Do you agree with the methodology Witness York is using to calculate the**
9 **proposed property tax expense adjustment?**

10 A7. No. While Witness York offers no explanation for her proposed property tax
11 adjustment, it appears that she is attempting to adjust property tax expense related
12 to ABATE's capital expenditure adjustments. This methodology bears no
13 resemblance to how the Company calculated property tax expense in this case,
14 which is described in my testimony beginning on page 7, line 20, and continuing
15 through page 13, line 6. If capital disallowances are ordered by the Commission,
16 the methodology that should be used to calculate the corresponding adjustment to
17 property tax expense should follow the same methodology the Company utilized to
18 calculate property tax expense in this case.

19
20 **Proposed Methodology for adjusting Property Tax Expense on Capital Disallowances**

21 **Q8. What property tax expense adjustment did Staff Witness Hecht propose?**

22 A8. Starting on page 7, line 9, and continuing through page 8, line 5 of Staff Witness
23 Hecht's testimony, Witness Hecht is recommending a reduction in property tax
24 expense for the projected test year of \$117,000. This is also shown on page 4 of
25 Witness Hecht's testimony in Figure 1. This is based on the Staff's adjustments to

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1 the Company's historic and projected capital expenditures and is calculated in WP-
2 JJH-1.

3
4 **Q9. Do you agree with the methodology Staff Witness Hecht is using to calculate**
5 **the proposed property tax expense adjustment?**

6 A9. Yes. Staff Witness Hecht's methodology is very similar to the methodology the
7 Company utilized to calculate property tax expense in this case.

- 8 • Capital adjustments to steam power generation, nuclear generation, and IT are
9 excluded.
- 10 • Capital adjustments for some of the more significant components of CWIP
11 are separately identified.
- 12 • Taxable capital adjustments impact the property tax liability the year after
13 they are incurred.
- 14 • First year STC multipliers of 96% and 50% are applied to capital adjustments
15 related to plant additions and CWIP, respectively, to calculate true cash value.
- 16 • True cash value is multiplied by 50% to calculate taxable value.
- 17 • Taxable value is multiplied by the estimated millage rate of 56.0 to calculate
18 the change in the property tax liability.
- 19 • Calendar year property tax expense is adjusted by 39% of the change in the
20 property tax liability in year 1 to reflect the Company's two-year expensing
21 methodology.

22

23 **Q10. If capital disallowances are ordered by the Commission, what methodology**
24 **should be used to calculate the corresponding adjustment to property tax**
25 **expense in this case?**

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1 A10. If capital disallowances are ordered by the Commission, Staff Witness Hecht's
2 methodology is reasonable and should be used to calculate the corresponding
3 adjustment to property tax expense. Staff Witness Hecht's methodology follows a
4 methodology that is very similar to the methodology the Company utilized to
5 calculate property tax expense, and any differences are immaterial in this case.

6

7 **Q11. Does this complete your rebuttal testimony?**

8 A11. Yes, it does.

1 JUDGE WALLACE: Please go ahead.

2 MS. REITZEL: Thank you. DTE now moves
3 to bind into the record the Direct Testimony of Matthew
4 A. Fix, which consists of a cover sheet and 47 pages of
5 questions and answers, and for the admission of eight
6 direct exhibits and schedules that Mr. Fix either
7 sponsored or cosponsored, which are designated as Exhibit
8 A-13 Schedule C5.11, Exhibit A-13 Schedule C5.12.1,
9 Exhibit A-21 Schedule K1, Exhibit A-21 Schedule K2,
10 Exhibit A-21 Schedule K3, Exhibit A-21 Schedule K4,
11 Exhibit A-21 Schedule K5, and Exhibit A-21 Schedule K6.
12 Mr. Fix also had rebuttal testimony, consisting of a
13 cover sheet and 17 pages of questions and answers, and
14 three rebuttal exhibits and schedules, designated as
15 Exhibit A-35 Schedule Z1, Exhibit A-35 Schedule Z2, and
16 Exhibit A-36 Schedule AA5.

17 JUDGE WALLACE: Thank you. Is there any
18 objection to binding in the direct and rebuttal testimony
19 of Mr. -- I'm sorry, what was the name again? Fix?

20 MS. REITZEL: Fix, F-i-x.

21 JUDGE WALLACE: Is there any objection to
22 binding in the direct and rebuttal testimony of Mr. Fix?

23 Hearing none, the testimony is bound in.

24 Is there any objection to the admission
25 of the exhibits and associated schedules sponsored by

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

1 Mr. Fix?

2 Hearing none, we'll admit those at the
3 end of binding in the Company's case.

4 (Testimony bound in.)

5 - - -

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
DIRECT TESTIMONY
OF
MATTHEW A. FIX

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MATTHEW A. FIX

Line
No.

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

2 A1. My name is Matthew A. Fix (he/him/his). My business address is DTE Energy
3 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
5 Company (DTE Energy).

6

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

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

9

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

11 A3. I received a Bachelor of Business Administration with a major in human resources
12 and a Bachelor of Arts with a major in psychology from the University of Michigan
13 – Dearborn in 2008. I received a Master of Business Administration with a finance
14 concentration from the University of Michigan – Dearborn in 2013.

15

16 **Q4. What is your current position and work experience?**

17 A4. My current position is Director of Compensation and Retirement Income, which I
18 have occupied since 2022. I joined DTE LLC full-time in 2009 and held positions
19 with increasing responsibility in Human Resources. I became Manager of HR
20 Client Relations in 2013, Manager of Compensation in 2017, and assumed
21 responsibility for Retirement Income in 2021.

22

23 **Q5. What are your current responsibilities as Director of Compensation and**
24 **Retirement Income?**

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MATTHEW A. FIX

Line
No.

1 A5. As Director of Compensation and Retirement Income, I have overall responsibility
2 for the design, implementation, and administration of DTE Energy's compensation
3 and retirement income related plans, policies, and practices.

4
5 **Q6. Have you participated in DTE Electric or DTE Gas proceedings before the**
6 **Michigan Public Service Commission (MPSC or Commission)?**

7 A6. Yes. I provided support to the compensation and benefits witness in the following
8 cases:

9	U-18999	2017 DTE Gas General Rate Case
10	U-20162	2018 DTE Electric General Rate Case
11	U-20561	2019 DTE Electric General Rate Case
12	U-20642	2019 DTE Gas General Rate Case
13	U-20836	2022 DTE Electric General Rate Case
14	U-20940	2021 DTE Gas General Rate Case
15	U-21291	2024 DTE Gas General Rate Case
16	U-21297	2023 DTE Electric General Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A7. My testimony will present an overview of employee compensation practices and
4 benefit expense related to retirement income for DTE Electric for the 2022
5 historical test period and the 12 months ended December 31, 2025, projected test
6 period. Specifically, I will:

7 1. Provide support for the Company's projected pension costs, Employee Savings
8 Plan Expense and other retirement income benefits;

9 2. Support the Company's labor cost escalation assumptions used in Company
10 Witness Uzenski's development of the composite inflation factors for the
11 projected test period;

12 3. Provide an overview of the Company's compensation philosophy for non-
13 represented employees and the role that the Company's incentive plans play in
14 the overall reasonableness of its total compensation policies, including an
15 analysis of salaries for non-represented positions as of December 31, 2022,
16 relative to the market medians for comparable positions;

17 4. Describe the components of the Company's short-term and long-term incentive
18 compensation plans and support the inclusion of such cost in the Company's
19 revenue requirement, exclusive of the costs related to DTE Energy's Top Five
20 Executive Officers; and

21 5. Demonstrate that the quantifiable customer benefits of the Company's incentive
22 compensation plans exceed the corresponding expense, as required by the
23 Commission's traditionally mandated cost/benefit analysis of incentive
24 compensation expense.

25

Line
No.

1 In summary, my testimony will support the reasonableness and validity of the
2 projected employee benefits and compensation expense to be incurred by DTE
3 Electric for the projected test period.

4

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

6 A8. Yes. I am sponsoring in whole, or in part, the following exhibits:

7	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
8	A-13	C5.11	Projected Operation and Maintenance Expenses -
9			Employee Pension and Benefits
10	A-13	C5.12.1	Projected Operation and Maintenance Expenses –
11			Pension Cost - Qualified
12	A-21	K1	Employee Compensation Market Analysis:
13			December 31, 2022
14	A-21	K2	2023 Annual Incentive Plan and Rewarding
15			Employees Plan Metrics: DTE Electric Company
16	A-21	K3	2023 Annual Incentive Plan and Rewarding
17			Employees Plan Metrics: Nuclear Generation
18	A-21	K4	2023 Annual Incentive Plan and Rewarding
19			Employees Plan Metrics: DTE Energy Corporate
20			Services LLC
21	A-21	K5	2023 Long-Term Incentive Plan Performance Shares
22			Metrics
23	A-21	K6	2023 Incentive Plans Cost/Benefit Analysis

24

25 **Q9. Were these exhibits prepared by you or under your direction?**

Line
No.

1 A9. Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by
2 Witnesses Hooper and Uzenski.

3

4 **EMPLOYEE PENSION COSTS**

5 **Q10. What are pension costs?**

6 A10. Pension costs are those costs related to retirement benefits for the employees of
7 DTE Electric that are eligible to participate in the Company's defined benefit
8 pension plans. The Company's defined benefit pension costs are recognized under
9 Financial Accounting Standard Board's Accounting Standard Codification (ASC)
10 Section 715-30 (ASC 715-30). Costs for the Company's Savings Plan and other
11 defined contribution benefits are recognized separately.

12

13 **Q11. What are the components of pension costs?**

14 A11. Pension costs are measured at the beginning of each fiscal year, under ASC 715-
15 30, and include the following four pension cost components:

16

17 Service Costs: Service Costs represent the pension benefits earned by active
18 employees, on a present value basis, during the current period. Service Costs are
19 measured based on the expected benefits to be paid based on actuarial assumptions
20 including current and projected salaries, expected employee turnover, and life
21 expectancy.

22

23 Interest Costs: Interest Costs are the increase in the Projected Benefit Obligation
24 (PBO) due to the passage of time during the current period. The PBO is the
25 actuarial present value of benefits attributable to the pension benefit formula and

Line
No.

1 service accrued to date discounted back to current dollars at a discount rate selected
2 at the prior year-end. A discount rate of 5.19% was used in determining the PBO
3 as of December 31, 2022. Measuring the PBO as a present value at the beginning
4 of each fiscal year requires the accrual of an interest cost for the current period at a
5 rate equal to the prior year's discount rate. The discount rate used in measuring
6 Interest Costs, as well as Service Costs for the 2022 historical test period, was
7 2.91%, based on the interest rate environment at the end of 2021, and projected
8 benefit payments from the pension plan matched against a yield curve of corporate
9 bond rates, rated AA or higher, provided by Aon, the Company's independent
10 actuarial firm. This was then reviewed by PriceWaterhouseCoopers (PwC), the
11 Company's independent accounting firm in connection with its audit of the
12 Company's financial statements as filed with the Securities and Exchange
13 Commission (SEC). The 5.19% discount rate used for determining Interest Costs
14 and Service Costs for the projected test year is based on the discount rate as of
15 December 31, 2022, which reflects the traditional assumption that high-quality
16 corporate bond yields at the end of 2022 will remain unchanged from the rates
17 prevailing at the end of the historical test year.

18

19 Expected Return on Assets: The Expected Return on Assets (ERoA), which is an
20 offset to pension costs, is an estimate of the expected investment return during the
21 current period, on the Market Related Value of the assets invested in the pension
22 trust at the beginning of the year adjusted for any expected funding activity and
23 projected benefit payments for the year. While actual year-to-year investment
24 returns can vary significantly, the ERoA is determined based on forward-looking
25 long-term financial market expectations to avoid large swings in pension costs

Line
No.

1 based on short-term investment performance. DTE Electric's expected annual
2 return was 6.80% during the 2022 historical test year, as developed by NEPC LLC,
3 the Company's independent investment consulting firm, and reviewed by PwC in
4 connection with its audit of the Company's financial statements as filed with the
5 SEC. The ERoA is 7.60%, 7.90% and 7.80% in 2023, 2024 and 2025, respectively.
6 The increase in the ERoA is due primarily to an increase in the forward-looking
7 long-term capital market assumptions that reflects the impact of the negative market
8 performance in 2022. These ERoAs are based on market conditions and pension
9 funding status as of late 2022.

10

11 Amortizations: In addition to current period costs described above, pension costs
12 also include the effect of the delayed recognition of prior period costs. This
13 includes Unrecognized Gains and Losses and Prior Service Costs. Unrecognized
14 Gains and Losses are changes in the amount of either the PBO or the plan's assets
15 resulting from experience different from that assumed in actuarial assumptions.
16 Most notably, since discount rates and return on assets assumptions are based on
17 either point in time measurements or long-term estimates of expected returns,
18 differences arise whenever a change is made in the discount rates or when the actual
19 asset returns differ from long-term expectations. These gains and losses are
20 deferred and the amount of the unrecognized balance in excess of a corridor equal
21 to 10% of the greater of the PBO or the Market Related Value of assets is amortized
22 based on a period equal to the average remaining service life of employees covered
23 by the plans. Prior Service Costs arise from pension plan amendments that affect
24 future benefits. When a plan provision is changed that will affect future benefit
25 payments for existing employees or retirees, the resulting change in the PBO

Line
No.

1 liability is amortized over the average remaining years of service life of the active
2 employees.

3

4 **Q12. What is the level of pension funding reflected in the projected pension costs?**

5 A12. Based on the pension funding status on December 31, 2022, the Company is not
6 expected to fund pension plans in 2023, 2024 or 2025. While there is no planned
7 funding of DTE Electric's pension trust, \$50 million of pension assets related to the
8 DTE Gas Non-Union pension trust were transferred to DTE Electric's pension trust
9 assets in November 2023 in exchange for cash consideration. The reasons for these
10 transfers are explained by Witness Uzenski.

11

12 **Q13. How are pension costs expected to change between the historical test year and**
13 **the projected year?**

14 A13. As summarized on Exhibit A-13, Schedule C5.12.1, the Company's pension costs
15 are projected to decrease from \$90.987 million during the historical test year, which
16 includes the one-time cost of \$64.798 million related to settlement charges
17 recognized in 2022, to \$53.993 million for the projected test year. After adjustments
18 for the portion of pension costs capitalized and transferred, the Company's projected
19 pension expense is \$32.273 million, as reflected on Exhibit A-13, Schedule C5.12.1,
20 line 19.

21

22 **Q14. Is the pension expense included in the Company's proposed revenue**
23 **requirement?**

24 A14. No. Witness Uzenski sponsors the Company's proposal to continue to defer the
25 projected pension expense to the accumulated regulatory liability as initially

Line
No.

1 authorized by the Commission in its Order in Case No. U-20836. Thus, the
2 projected pension expense is not reflected in the Company's proposed revenue
3 requirement and the pension expense is eliminated on line 20 of Exhibit A-13,
4 Schedule C5.12.1.

5

6 **EMPLOYEE SAVINGS PLAN COSTS**

7 **Q15. What is included in Employee Savings Plan expense reflected on Exhibit A-13,**
8 **Schedule C5.11, line 5?**

9 A15. The Company's Employee Savings Plan is an employee benefit plan that allows
10 eligible employees the opportunity to contribute a certain percentage of their annual
11 earnings that the Company matches, generally up to 6% of annual salaries and
12 wages for non-represented employees and for most represented groups. In addition,
13 employees hired after the Company's defined benefit pension plans were closed to
14 new hires receive an additional Company contribution of 4.0% of their pay,
15 although certain represented employees receive a Company contribution of 8.0%
16 of their pay.

17

18 **Q16. What adjustments are you proposing to the Company's Employee Savings**
19 **Plan expense?**

20 A16. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 5, I am proposing two
21 adjustments to Employee Savings Plan expense. The first, which is reflected on
22 column (c), represents a normalization of the Company's recorded 2022 Employee
23 Savings Plan expense and the second, which is reflected in column (h), represents
24 the projection of this expense through the end of the projected test year.

Line
No.

1 **Q17. Why is a normalization adjustment required for the Company's recorded 2022**
2 **Employee Savings Plan expense as reflected on Exhibit A-13, Schedule C5.11,**
3 **page 2, line 5, column (c)?**

4 A17. The Company experienced an abnormally high level of employee resignations in
5 2021, which were likely driven by the transition out of the COVID-19 pandemic,
6 that resulted in an abnormally high level of forfeitures recognized in 2022.
7 Specifically, the Company recognized a reduction in its Employee Savings Plan
8 expense arising from forfeitures, predominately due to the departure of non-vested
9 employees in 2021 of \$0.837 million, whereas the five-year average of forfeitures
10 prior to 2022 was \$0.459 million, resulting in excess forfeitures of \$0.378 million.
11 Because the elevated level of forfeitures in 2021 was the result of a once in a
12 century pandemic, it is proper to normalize 2022 for the impact of forfeitures in
13 excess of a normal level. The elimination of excess forfeitures results in a
14 normalized 2022 Employee Savings Plan expense of \$30.077 million as shown on
15 page 2 of Exhibit A-13, Schedule C5.11, page 2, line 5, column (d).

16

17 **Q18. How was the projected Employee Savings Plan expense developed?**

18 A18. The projected Employee Savings Plan expense was developed based on the
19 normalized 2022 expense escalated by the four-year average of the annual increase
20 in the Company's Employee Savings Plan costs for the years 2017 through 2020 of
21 7.50%. This results in Employee Savings Plan expense for the projected test year
22 of \$37.406 million.

23

Line
No.

1 **Q19. Why have you not included the annual percentage increase in the Company's**
2 **Employee Savings Plan costs for 2021 and 2022 in the historical average**
3 **annual increase?**

4 A19. In 2021, the Company's Employee Savings Plan costs were impacted by the low
5 level of new employees during the COVID-19 pandemic. Plus, in 2022 the
6 Company recognized an abnormally high level of forfeitures arising from
7 employee resignations in 2021, as the economy transitioned out of the pandemic.
8 Accordingly, the Company's experience in both 2021 and 2022 were impacted by
9 the same non-recurring item, to-wit, the once in a century worldwide pandemic.
10 Since both years were impacted, both the 2021 and 2022 annual increase should
11 be excluded from the historical annual rate of change in the Employee Savings
12 Plan costs. This is consistent with the methodology adopted by the Commission
13 in its Order in the Company's most recent rate case which adopted the
14 recommendation of the Administrative Law Judge (Case No. U-21297, Order
15 December 1, 2023, p. 191).

16

17 **Q20. Why did you escalate the adjusted historical test year Employee Savings Plan**
18 **expense by the average annual increase in the Company's Savings Plan costs**
19 **rather than the annual increase in the Company's Savings Plan expense?**

20 A20. Since the Company's Employee Savings Plan expense is impacted by the
21 proportion of the costs that are capitalized, the annual changes in the Company's
22 Employee Savings Plan expense reflects both the effect of the changes in costs and
23 changes in the proportion of the costs capitalized. For example, the five-year
24 average of the annual increase in Employee Savings Plan expense was 6.20% for
25 the years 2018 through 2022, but this reflects an increase in the proportion of costs

Line
No.

1 capitalized from 31.3% in 2017 to 39.6% in 2022. This increase in the proportion
2 of costs capitalized reflects the significant increase in the Company's capital
3 expenditures over this time frame, which is assumed to remain constant through the
4 projected test year. Therefore, under the assumption that the proportion of costs
5 capitalized will not increase in the future, the historical average annual increase in
6 the Company's Employee Savings Plan costs of 7.50% for the years 2017 through
7 2020, as described in Q18 is a more accurate measurement of the projected increase
8 in the Company's Employee Savings Plan expense.

9

10 **OTHER EMPLOYEE BENEFITS COSTS**

11 **Q21. What are Other Benefits Costs?**

12 A21. The costs of the Company's Other Employee Benefits are also reflected on Exhibit
13 A-13, Schedule C5.11 (lines 13 through 25). These costs include a variety of other
14 benefits including, Executive and Supplemental Retirement Plans, Supplemental
15 Severance Plan, Supplemental Savings Plan (SSP), Deferred Compensation and
16 Retirement Administration Fees. The remaining Other Benefits Costs are described
17 by Witness Hooper.

18

19 **Q22. What is the basis for the Supplemental Severance Plan cost projections?**

20 A22. The Supplemental Severance Plan, which was implemented on July 1, 2016, is
21 designed to address the differences in full benefit eligibility retirement ages
22 between the DTE Traditional Pension Plan and the MCN Energy Group, Inc
23 (MCN) Traditional Pension Plan. As a severance plan, in accordance with the
24 regulations of the U.S. Department of Labor, it is not subject to participation,
25 vesting and funding requirements of ERISA. Eligible employees will receive a

Line
No.

1 lump sum payment equal to the present value of the difference between the DTE
2 Pension Plan and the MCN Pension at the termination of employment. Aon
3 developed the projected cost of this plan, which is estimated to decrease from
4 \$0.734 million in 2022 to \$0.110 million for the projected test year, as reflected
5 on Exhibit A-13, Schedule C5.11, line 14.

6

7 **Q23. What is the Supplemental Savings Plan?**

8 A23. The SSP is a non-qualified benefit plan that does not meet the requirements under
9 the Internal Revenue Code to be eligible for certain tax advantages, such as the
10 deductibility by the Company of any contributions. Each year, the Internal
11 Revenue Service (IRS) establishes limitations on employee annual eligible
12 compensation and annual contributions to tax advantaged plans. To the extent an
13 employee's annual eligible compensation or annual contributions, including the
14 Company's match, to the Company's qualified plan exceeds the IRS limitations,
15 employees that are Director level and above are eligible to participate in the SSP.
16 By participating in the SSP, employees accrue benefits that are identical to the
17 benefits available under the qualified savings plan. As such, the SSP is a "make-
18 whole" benefit plan that merely puts the participating employees in the same place
19 they would be in the absence of the IRS limitations.

20

21 **Q24. What adjustments are you proposing to the SSP expense?**

22 A24. I am proposing two adjustments to SSP expense. The first relates to a
23 normalization of the actual 2022 SSP expense and the second relates to a
24 projection of the SSP expense through the end of the projected test year.

25

Line
No.

1 **Q25. What is the normalization adjustment for 2022 SSP expense?**

2 A25. Since the Company does not separately fund the Company's matches to the
3 employees' contributions, the earnings and losses from the employees' directed
4 investments is a cost incurred by the Company. The SSP normalization adjustment
5 reflects an annual return on the investments of 6.80% in 2022, which is based on
6 the ERoA used in the determination of the Company's pension costs in the
7 historical test year. This results in a normalized SSP expense of \$2.456 million
8 compared to a negative expense of \$3.599 million recorded in 2022, which
9 represents an increase in SSP expense of \$6.055 million, as reflected on page 2 of
10 Exhibit A-13, Schedule C5.11, line 15, column (c). The increase in SSP expense
11 reflects the difference between the negative return on the investments in the SSP
12 and the ERoA of 6.80%.

13

14 **Q26. What is the basis for projected the SSP expense for the projected test year?**

15 A26. The increase in the normalized 2022 SSP expense of \$2.456 million to \$3.207
16 million for the projected test year, as shown on Exhibit A-13, Schedule C5.11, line
17 15, reflects an increase in the Company's matching contributions based on
18 projected salary escalations and an increase in the expected earnings on designated
19 investments. The SSP projection reflects an annual return on the investments of
20 7.60% in 2023, 7.90% in 2024 and 7.80% in 2025, consistent with the ERoA used
21 in the determination of the Company's pension costs in the projected test year.

22

23 **Q27. What adjustments are you proposing to Deferred Compensation Plan**
24 **expense?**

Line
No.

1 A27. I am proposing two adjustments to Deferred Compensation expense. The first
2 relates to a normalization of the actual 2022 Deferred Compensation expense and
3 the second relates to a projection of the Deferred Compensation expense through
4 the end of the projected test year.

5

6 **Q28. What is the normalization adjustment for 2022 Deferred Compensation**
7 **expense?**

8 A28. Similar to the SSP, the Company's recorded costs are based on the return on the
9 investment directives of the participating employees since the deferrals are not
10 funded by the Company. The Deferred Compensation normalization adjustment
11 reflects an annual return on the investments of 6.80% in 2022, which is based on
12 the EROA used in the determination of the Company's pension costs in the
13 historical test year. This results in a normalized Deferred Compensation expense
14 of \$88,000 compared to a negative expense of \$85,00 recorded in 2022, which
15 represents an increase in Deferred Compensation expense of \$173,000, as
16 reflected on page 2 of Exhibit A-13, Schedule C5.11, line 16, column (c). The
17 increase in Deferred Compensation expense reflects the difference between the
18 actual negative return on the investments in the Deferred Compensation balances
19 in 2022 and the Pension EROA of 6.80%.

20

21 **Q29. What is the basis for the projected Deferred Compensation Plan expense?**

22 A29. The increase in the normalized 2022 Deferred Compensation Plan expense of
23 \$88,000 to \$95,000 for the projected test year, as shown on Exhibit A-13, Schedule
24 C5.11, page 2, line 16, column (j), reflects an increase in the expected earnings on
25 designated investments. The Deferred Compensation Plan projection reflects an

Line
No.

1 annual return on the investments of 7.60% in 2023, 7.90% in 2024 and 7.80% in
2 2025, consistent with the ERoA used in the determination of the Company's
3 pension costs in the projected test year.

4

5 **Q30. How did you develop the projections for Retirement Administration Fees**
6 **included in Other Benefits on Exhibit A-13, Schedule C5.11?**

7 A30. Retirement Administration Fees (line 23) in 2022 of \$325,000 are projected to
8 increase to \$354,000, based on the projected overall inflation rate assumptions.

9

10 **LABOR COST ESCALATION**

11 **Q31. What annual labor cost escalation assumptions are appropriate for the**
12 **projected test period?**

13 A31. Annual labor cost escalation assumptions are required for both the Company's
14 represented and non-represented employees. Based on existing Collective
15 Bargaining Agreements, the Company is obligated to increase pay rates by at least
16 3% annually through the term of the contracts. In addition to scheduled pay rate
17 increases, the agreements also provide for progression increases for those
18 employees that have not yet achieved the maximum pay rate for their positions.

19

20 Non-represented employee compensation is generally adjusted annually based on a
21 review of pay practices of other employers, changes in the external competitive
22 market and internal pay equity. Consistent with this practice, all non-represented
23 non-management employees received an overall pay increase of 3% in 2023. This
24 3% pay adjustment was comparable to the annual pay adjustments in every year

Line
No.

1 since 2010. In addition to the annual pay adjustment program, employees generally
2 receive pay increases based on promotions.

3 Based on the above, I have determined that annual escalations of 3.0% for 2023,
4 2024, and 2025 are a conservative estimate of the Company's expected increase in
5 its labor rates.

6

7 **EMPLOYEE COMPENSATION**

8 **Q32. What is the Company's compensation philosophy and framework for non-**
9 **represented employees other than Executives?**

10 A32. Non-represented employees are those employees not covered by any Collective
11 Bargaining Agreements with the Company's union organizations. Compensation
12 for employees covered by Collective Bargaining Agreements is established
13 pursuant to negotiations. Non-executive employees are generally defined as those
14 with titles below Vice President level. DTE Electric's compensation philosophy
15 is to provide pay programs that: 1) attract, retain, and motivate employees; 2)
16 ensure that pay is externally competitive (i.e., paid near market median); and 3)
17 differentiate total rewards based on both organizational unit results and individual
18 contributions.

19

20 At DTE Electric, total annual compensation for all non-represented employees has
21 two primary components: base pay and variable pay, as delivered through the
22 Company's incentive compensation programs. Employee base pay is reviewed
23 annually and adjusted (if appropriate) based on the position relative to what the
24 external market pays for similar positions and individual performance. Variable
25 pay is based on the achievement of Company, as well as departmental and

Line
No.

1 individual results. Variable pay is made up of both short-term incentive and long-
2 term incentive plans.

3 **Q33. How does the Company's philosophy regarding incentive compensation**
4 **compare with that of its peers?**

5 A33. Incentive compensation programs are a component of total compensation practices
6 for the vast majority of energy companies for their non-represented employee
7 populations, as described below. Base pay is set lower than it otherwise would be
8 because of the variable pay component. When considered holistically, the
9 Company's base and variable pay plans provide a framework of market-based total
10 annual compensation pay opportunities for non-represented employees. It is the
11 total annual cash compensation, as represented by these two components, that
12 prospective and current employees use to gauge whether DTE Electric's
13 compensation is competitive with other potential employers.

14

15 **Q34. How does the Company's non-represented compensation philosophy and**
16 **framework benefit customers?**

17 A34. DTE Electric's compensation philosophy and framework provides a benefit to
18 customers by attracting and retaining employees with the requisite skills and
19 experience to ensure safe, reliable, and high-quality customer service delivery, and
20 by recognizing and rewarding effective and efficient performance. A competitive
21 compensation policy also serves to effectively retain employees, minimizing the
22 risks and costs of high employee attrition. This philosophy directly benefits all
23 customers by providing a high level of service at a competitive cost and provides
24 incentives to focus future job performance on those activities that provide the most
25 benefit to customers.

Line
No.

1

2 **Q35. What is the external comparative market used by the Company to determine**
3 **the external market for compensation?**

4 A35. The external comparative market for positions varies based on the specific job.
5 Some jobs are compared to those in utilities of similar size (e.g., revenue, number
6 of employees, etc.), other jobs are compared to general industry located in
7 Southeastern Michigan, and yet other jobs to general industry located within the
8 United States. The relevant market will depend upon the requisite skills and
9 abilities required of the job and the nature of the recruitment source. For example,
10 the comparative market for an administrative assistant is the general industry
11 within Southeastern Michigan while the comparative market for a manager of
12 nuclear operations is utilities within the Midwestern United States (primarily), or
13 within the entire United States (secondarily).

14

15 **Q36. How is benchmark data obtained from the external comparative market?**

16 A36. The Company participates in and/or purchases published salary surveys from
17 several different organizations. The surveys typically report median base salary,
18 target incentives, and median total cash compensation by job classification.

19

20 **Q37. How are base salaries determined?**

21 A37. Base salaries are targeted around the median base salary levels of the competitive
22 market as adjusted for differences in company size and scope where appropriate.
23 All non-executive positions are placed in a salary zone based on external
24 benchmarking. The mid-point of the salary zone is based on the market median
25 for comparable work in comparable companies. A range is provided above and

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1 below the midpoint to allow for differentiation based on applicable skills and
2 experience, as well as demonstrated performance. The ranges are reviewed
3 periodically to help ensure they remain competitive in the external market.

4

5 **Q38. Does the Company benchmark the variable component of compensation?**

6 A38. Yes. The Company reviews several surveys that provide information on a number
7 of variable pay indices. In addition, the surveys report data for employee groupings
8 such as exempt employees, non-exempt employees, managers, and executives.

9

10 **Q39. Could an alternate compensation system be structured, eliminating variable**
11 **components?**

12 A39. Yes. The Company could raise employees' base pay to the market levels for total
13 compensation in lieu of providing variable pay opportunities to maintain a
14 competitive total compensation level. However, this would have several
15 undesirable effects. For example, raising employees' base pay to the total
16 compensation market levels would result in a higher level of fixed costs tied to base
17 salaries, such as certain defined contribution benefit plans, life insurance, disability
18 insurance, and other salary-based employee benefits. Moreover, given the well-
19 recognized motivational value of variable pay compensation programs, as
20 described below, delivering employee compensation solely in fixed salary would
21 diminish the performance incentive for employees to provide superior service to
22 customers. Annual incentives ensure that individuals have an element of "at risk"
23 compensation that allows the Company to differentiate pay based on performance
24 and allocate compensation to those employees that are most deserving.

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1 **EXECUTIVE COMPENSATION**

2 **Q40. How does the compensation program for executives differ from that for non-**
3 **executives?**

4 A40. The compensation program for executives differs in three respects. First, the
5 comparative market for compensation benchmarking is defined as a specific group
6 of peer companies from which data are obtained through a custom study generally
7 performed every two years. Second, a higher proportion of executives'
8 compensation is delivered in the form of variable pay. The third way in which the
9 executive compensation program differs is with respect to governance. The
10 compensation programs for Company executives must be approved by the
11 Organization and Compensation Committee of the DTE Energy Board of
12 Directors.

13

14 **Q41. What is the comparative market for executive compensation?**

15 A41. The comparative market used by DTE Energy for determining the alignment of its
16 executive compensation programs with similar companies consists primarily of
17 utilities (including utility holding companies) and broad-based energy companies
18 selected on the basis of revenues, financial performance, geographic location, and
19 availability of compensation information.

20

21 **Q42. What are the key components of the Executive Compensation Program?**

22 A42. The key elements of the Executive Compensation Program are base salary and
23 variable pay (annual incentive plan and long-term incentive awards).

24

25 **Q43. How are base salaries determined?**

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1 A43. Base salaries are targeted around the median of the comparative market.
2 Appropriate methods of measurement are used to consider differences in company
3 size and scope. In addition, midpoints are established for those executives whose
4 jobs cannot be easily matched in the comparative market. These midpoints are
5 designed to allow adequate differentiation for 1) individual potential, 2)
6 contributions made, and 3) the length of time the executive has been in his or her
7 position.
8

9 **COMPETITIVE COMPENSATION ANALYSIS**

10 **Q44. Has the Company prepared an analysis of its compensation practices relative**
11 **to the market medians?**

12 A44. Yes. DTE Electric has performed an analysis of virtually all incumbent salaries as
13 of December 31, 2022, showing that DTE's compensation practices are competitive
14 with market medians. Exhibit A-21, Schedule K1 reflects a summary of the market
15 median for all DTE Electric positions for which corresponding positions have been
16 identified, other than those employees covered by collective bargaining
17 agreements. In addition, Exhibit A-21, Schedule K1 reflects those positions at DTE
18 LLC that primarily support DTE Electric. Exhibit A-21, Schedule K1 reflects
19 employee compensation information organized based on Career Family
20 classifications used by DTE Electric. A Career Family is a grouping of jobs based
21 on similar skill requirements and job content in a specialized discipline (i.e.,
22 Finance, Engineering, Information Technology, etc.) that may or may not fit into a
23 business unit organizational structure. For example, Engineering or Finance Career
24 Families could exist in several organizational units.
25

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1 **Q45. How is an analysis of a competitive pay structure performed?**

2 A45. An analysis of market-based pay structure is performed by identifying comparable
3 positions and determining the compensation ranges paid by similar employers in
4 relevant locations. A more expansive description of the means of assessing a
5 competitive pay structure is provided in an article published by Salary.com,
6 entitled The Basics of Market Pricing a Job (January 26, 2017).

7

8 **Q46. Is the Company's use of a market pricing approach to employee compensation**
9 **consistent with others?**

10 A46. Yes. According to a recent survey performed by WorlDatWork and Deloitte
11 Consulting, entitled 2019 Survey of Salary Structure Policies and Practices, more
12 than half of the companies surveyed use a market pricing model for setting
13 compensation levels.

14

15 **Q47. Why are employees covered by collective bargaining agreements excluded**
16 **from this analysis?**

17 A47. Compensation levels for unionized employees are determined through a negotiated
18 process, which involves a variety of work rules and benefit related issues, rather
19 than determined strictly through market analysis. Moreover, the specialized skills
20 and experience required by many of the positions are not readily comparable to
21 other positions in the local market. Thus, a comparison of pay levels for those
22 employees covered by collective bargaining agreements is not useful in this
23 context.

24

25 **Q48. What conclusions can be drawn from Exhibit A-21, Schedule K1?**

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1 A48. In summary, Exhibit A-21, Schedule K1 demonstrates that the weighted average
2 of the annual base compensation for all positions with incumbents as of December
3 31, 2022, with available position matches was a mere 0.1% higher than the average
4 of median market base compensation. Plus, this analysis further demonstrates that
5 total cash compensation for all positions with incumbents as of December 31,
6 2022, with available position matches was 0.4% less than the average of median
7 market for total cash compensation. This analysis concludes that the Company's
8 total compensation is insignificantly different from the market medians and
9 confirms that the Company's compensation practices are consistent with the
10 Company's compensation policy to pay employees near the market median for
11 comparable positions on a total cash compensation basis. Moreover, a comparison
12 of the Company's base salaries, which excludes short-term incentive
13 compensation, to the market medians for total cash compensation, which is
14 inclusive of short-term incentive compensation, shows that in the absence of the
15 Company's short-term incentive compensation programs, the Company's pay
16 would be 10.7% less than the market medians.

17

18 **Q49. What is included in the total cash compensation amounts?**

19 A49. Total cash compensation reflects base pay as of December 31, 2022, and the Target
20 payout levels for those employees eligible to participate in the Company's short-
21 term incentive compensation programs. Although the analysis on Exhibit A-21,
22 Schedule K1 does not reflect the value of the Company's Long-Term Incentive
23 Plan, as it is primarily for executive level positions, a separate analysis of
24 executive compensation prepared by Aon, which is inclusive of long-term plans,

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1 shows that total compensation is about 9% less than the median of the Company's
2 peer group, as discussed in more detail below.

3

4 **Q50. How was the market median for the positions determined?**

5 A50. As described above, the Company subscribes to several compensation survey
6 providers that create comprehensive databases of job descriptions that enables the
7 Company to match the job requirements, including education, expertise and
8 experience of existing positions with market surveys. After matching job positions
9 are identified, actual base and total compensation ranges are developed from the
10 salary survey database. The information on Exhibit A-21, Schedule K1 was
11 derived from the Company's compilation of the compensation for positions with
12 an incumbent as of December 31, 2022.

13

14 **Q51. What proportion of DTE Electric's total employee population as of December**
15 **31, 2022, is reflected in this analysis?**

16 A51. As of December 31, 2022, practically all (99.5%) of the employee population at
17 DTE Electric, as well as DTE LLC employees that provide supporting services to
18 DTE Electric. This is exclusive of those employees represented by collective
19 bargaining agreements.

20

21 **INCENTIVE COMPENSATION**

22

23 **Q52. What are you proposing regarding the level of incentive compensation expense**
24 **to be included in the Company's revenue requirement?**

25 A52. I am proposing that the projected incentive compensation expense of \$59.504
26 million related to the Company's short-term and long-term incentive compensation

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1 plans be included in the revenue requirement adopted by the Commission in this
2 proceeding, as described in more detail below. The components of the projected
3 \$59.504 million of incentive compensation expense are detailed in Table 3 reflected
4 in response to Q79.

5

6 **Q53. Is the Company requesting recovery in rates for all incentive compensation**
7 **expenses?**

8 A53. No. While the Company's compensation expenses are reasonable, \$10.157 million
9 of incentive compensation expense related to DTE Energy's Top Five Executive
10 Officers has been excluded. This exclusion is reflected on Exhibit A-3, Schedule
11 C19 as supported by Witness Uzenski and has been excluded from Table 3 reflected
12 in the response to Q79.

13

14 **Q54. What is the basis for your proposed inclusion of \$59.504 million of incentive**
15 **compensation expense in the Company's revenue requirement?**

16 A54. In summary, my proposal to include all the Company's projected incentive
17 compensation expense, exclusive of the portion related to the Top Five Executive
18 Officers, is based on the prevalence of incentive compensation programs and the
19 resultant need for the Company to have total compensation programs that enable
20 it to be competitive with other employers. As described above, the Company's
21 existing total cash compensation is in line with the market, as is the total
22 compensation for its executives. Moreover, in the absence of the incentive
23 compensation programs, total cash compensation for the Company's employees
24 would be unreasonable as it would total 10.7% less than the market medians, as
25 reflected on Exhibit A-21, Schedule K1, and total compensation for its executives

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1 would be 70% less than market, as reflected in Table 2 below in Q59. The
2 remainder of my testimony will demonstrate that the Company's incentive
3 compensation programs are both reasonable and prudent and, therefore, a
4 necessary cost of the Company doing business that should be reflected in the
5 Company's revenue requirements.

6

7 **Q55. Are there any employee motivational advantages to including an incentive-**
8 **based compensation component in a company's overall compensation design?**

9 A55. Yes. The underlying principle of incentive compensation plans is to motivate
10 improved organizational performance. An effective incentive compensation plan
11 provides a "pay-for-performance" environment intended to motivate individual
12 and team achievement of measurable goals.

13

14 **Q56. Is there any evidence that incentive-based compensation is effective in**
15 **motivating improved organizational performance?**

16 A56. Yes. A comprehensive analysis of the impact of incentive compensation plans on
17 organizational performance concluded that programs that provide tangible
18 incentives for achievement of certain goals lead to a 27% increase in
19 organizational performance (Incentives, Motivation and Workplace Performance:
20 Research & Best Practices, The International Society for Performance
21 Improvement, Spring, 2002). This study observes that the source for such
22 organizational performance improvements is that employees 1) value their work
23 tasks more, 2) have more self-confidence and esteem for their employers, 3) are
24 more persistent at work tasks, and 4) strive for high levels of accomplishments.
25 Moreover, this study notes that long-term incentive plans provide even greater

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1 performance improvements. In addition, an Aon study of Variable Compensation
2 Measurement Survey issued in 2018 reported that 86% of participants in the
3 survey indicated that their variable compensation plans resulted in improved
4 business results.

5

6 **Q57. Are incentive compensation programs a typical element in compensation at**
7 **other companies?**

8 A57. Yes. According to a 2021 study issued by WorldatWork and Compensation
9 Advisory Partners, most companies had short-term and long-term incentive
10 programs. This indicates that incentive compensation programs are a prevalent
11 practice among most companies. (Incentive Pay Practices, Publicly Traded
12 Companies, WorldatWork and Compensation Advisory Partners). Moreover, a
13 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas
14 Service providers utilized broad-based incentive compensation programs.

15

16 **Q58. Do the Company's incentive compensation plans result in unreasonable**
17 **compensation?**

18 A58. No. As explained above, the Company benchmarks its total compensation for non-
19 represented employees against relevant peers, inclusive of incentive compensation,
20 and establishes a mid-point salary range based on the median market level.
21 Moreover, based on a recent survey by Aon, the total compensation of DTE
22 Energy's Executives is about 9% less than the median of its peers based on Target
23 level performance, inclusive of the long-term incentive compensation. The
24 Company's incentive compensation programs are merely a component of the total
25 compensation policies required for the Company to be competitive with its peers,

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1 rather than a supplement. Indeed, in the absence of the incentive compensation
2 programs, total compensation for the Company's non-represented population
3 would be more than 10% below market, as reflected on Exhibit A-21, Schedule K1.
4 Additionally, as indicated in Table 2 in the response to Q59 below, DTE Energy's
5 Executives would be substantially less than its peers, since about 70% of total
6 compensation is delivered through short and long-term incentive compensation
7 programs, by both DTE and its peers.

8

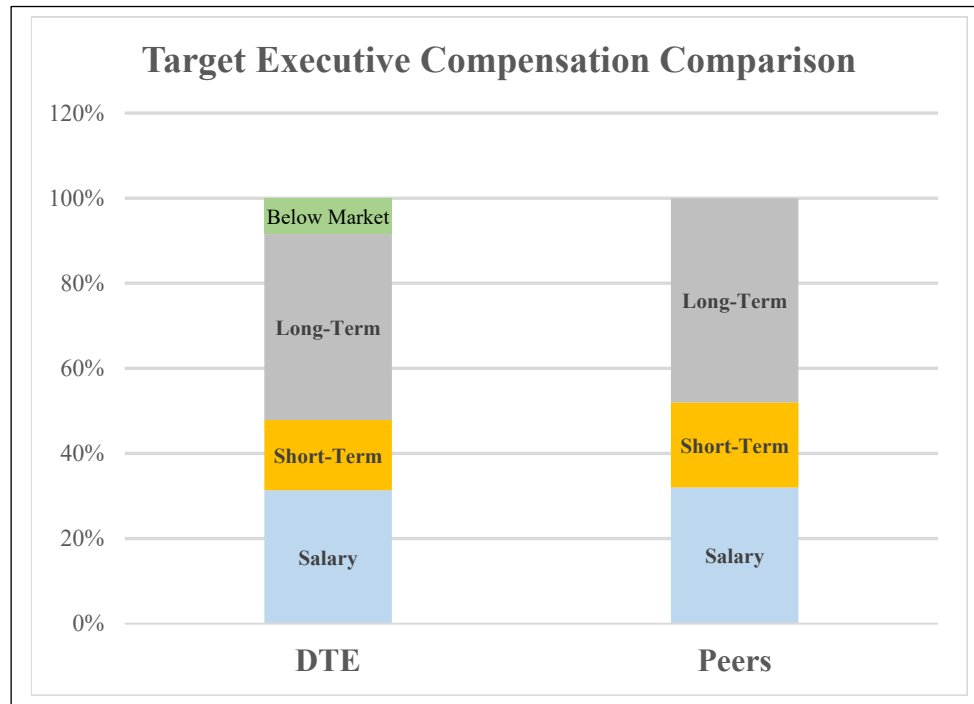
9 **Q59. How do the components of the Company's total Executive compensation**
10 **practices compare to the Company's peers?**

11 A59. Based on the Aon survey referenced above, a comparison of the relative magnitude
12 of the Company's salary, short-term and long-term pay components for Executives
13 to the 50th percentile of its peers is reflected in Table 2.

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1

Table 2



2

3 **Q60. What are the specific components of the Company's incentive compensation**
 4 **programs?**

5 A60. The Company has in place incentive compensation plans for both its Executive
 6 and all other non-represented employees. Short-term incentive plans are provided
 7 through the Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP).
 8 Additionally, a multiple year incentive plan, which is available to all managers and
 9 above and up to 10% of other eligible non-represented employees, is delivered
 10 through Performance Shares granted pursuant to the Long-Term Incentive Plan
 11 (LTIP).

12

13 **Q61. What is the AIP?**

14 A61. The AIP is a short-term variable pay program available to senior management
 15 level employees to motivate performance. The 2023 AIP measures and relative

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1 weights for DTE Electric (other than Nuclear Generation), Nuclear Generation,
2 and DTE Energy Corporate Services LLC are reflected on Exhibit A-21,
3 Schedules K2, K3 and K4, respectively. For each measure, a Target is established
4 for which a 100% payout will be earned. Performance less than Target, but above
5 a minimum Threshold, results in a payout between 25% of Target and 100%,
6 performance at Target results in a payout of 100%, and performance between
7 Target and the Maximum level results in a payout of up to 175% of Target for non-
8 executive participants of the AIP and up to 200% of Target for Executive
9 participants of the AIP.

10

11 **Q62. Which employee classifications are eligible to participate in the AIP?**

12 A62. All Executive level employees, generally those with titles of Vice President and
13 above, and Directors participate in the AIP. All other non-represented employees
14 are eligible to participate in the REP.

15

16 **Q63. What are the components of the REP?**

17 A63. The REP is identical to the AIP except that Threshold performance is at 50% of
18 Target and the Maximum performance payout is 150% of Target. The 2023 REP
19 measures and weightings are reflected on Exhibit A-21, Schedules K2 through K4.
20 The REP measures are identical to the AIP measures other than the REP excludes
21 the Gallup survey of employee engagement measure in recognition that the
22 Company's leadership is responsible for providing an environment of high
23 employee engagement.

24

25 **Q64. What are the categories of measures included in the AIP and REP?**

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1 A64. There are four categories of measures in both the AIP and REP. Specifically,
2 Financial Performance, Customer Satisfaction, Safety and Engagement, and
3 Operating Excellence.

4

5 **Q65. What are the financial measures included in the AIP?**

6 A65. There are three financial measures for DTE Electric employees that are designed
7 to create a clear line of sight for all employees to focus on operating excellence by
8 rewarding employees when the Company is successful.

9 1) DTE Electric Operating Earnings objective is based on the Company
10 realizing the Commission authorized return on equity.

11 2) DTE Electric's Cash from Operations is similarly based on the authorized
12 return on equity but is adjusted for non-cash items. The inclusion of a cash
13 flow measure recognizes the importance of DTE Electric maintaining a high
14 credit rating to allow continued access to the capital markets at reasonable
15 costs and terms to ensure sufficient capital investment to continue to serve
16 our customers.

17 3) DTE Energy's Earnings per Share measure is based on the midpoint of 2023
18 earnings guidance.

19 Nuclear Generation Financial Performance measures consist of DTE Electric
20 Operating Earnings and Nuclear Generation Operation and Maintenance Expense.

21 The Financial Performance measures for DTE LLC reflect DTE Energy's
22 Operating Earnings per Share and Cash from Operations.

23

24 **Q66. What are the Customer Satisfaction measures?**

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- 1 A66. There are two customer satisfaction measures that are intended to focus employees
2 on improving the experience that our customers have in their interactions with the
3 Company. The measures are:
- 4 1) The Net Promoter Score is a measure of the extent to which customers are likely
5 to recommend the Company to their friends and colleagues. The Target in 2023
6 is 39, which is the same as the actual NPS in 2022. However, macroeconomic
7 factors in 2022 and 2023, including 40-year high inflation and historically low
8 consumer confidence, as noted by the University of Michigan Consumer
9 Confidence Surveys results, among other factors, have resulted in reduced NPS
10 scores nationwide by virtually all industries. Therefore, considering these
11 conditions, maintaining a NPS score of 39 in 2023 is estimated to represent an
12 effective 4 point increase.
- 13
- 14 2) The MPSC Customer Complaints measure represents the number of formal
15 complaints made to the MPSC regarding both DTE Gas and DTE Electric as
16 reported to the Company by the MPSC. The MPSC Customer Complaints
17 Target for 2023 is 1,912.
- 18
- 19 **Q67. What are the measures related to Safety and Engagement?**
- 20 A67. There are three measures related to safety and engagement. One measure pertains
21 to employee engagement as measured by the Gallup survey, as well as two
22 employee safety related measures, as described below.
- 23
- 24 **Q68. What is the measure related to Employee Engagement?**

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1 A68. The Gallup measure of Employee Engagement is reflective of the direct correlation
2 between the level of active employee engagement and the performance of an
3 organization. The 2023 Target of 4.26 is based on a grand mean of the results of
4 the Gallup surveys of employees and represents top decile performance relative to
5 Gallup's overall database. Employee Engagement is a statistically significant
6 measure of the level of commitment employees have to an organization's success
7 and is not merely a measure of employee satisfaction.

8

9 **Q69. What are the Safety related measures?**

10 A69. DTE Electric has two safety-related measures.

11 1) The first is the OSHA Recordable Incident Rate (RIR), which measures the
12 recordable injuries per 100 employees divided by the actual number of hours
13 worked, as defined by the Occupational Safety and Health Administration
14 (OSHA). This is a standard measure of safety performance used nationwide.
15 The measure is intended to create a heightened focus on the importance of
16 safety in the workplace. The RIR Target for 2023 is .57, which is near the very
17 top performance in the industry.

18 2) The second is High Energy Serious Injury or Fatality (HSIF), which is a
19 measure adopted by the Edison Electric Institute that recognizes the degree of
20 seriousness of an injury in the context of a dangerous event. The 2023 Target
21 of two is based on an improvement from the five-year average of 4.

22

23 **Q70. What are the Operating Excellence measures for 2023?**

24 A70. DTE Electric has four Operating Excellence measures that reflect specific operating
25 priorities for 2023 to motivate the achievement of certain operating objectives

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1 important to the Company, its customers, and the Commission. Two of these
2 measures relate to Distribution System Reliability and the other two relate to
3 Generation Reliability.

4

5 The two Electric Distribution Reliability Measures are:

6 1) The System Average Interruption Duration Index (SAIDI) exclusive of
7 Major Event Days (MEDs). The 2023 Target is 150 minutes.

8 2) The percentage of customers that experience four interruptions or more
9 (CEMI4) in a calendar year. The Target in 2023 is 7.55%.

10

11 The two Generation Reliability Measures are:

12 1) The percentage of hours that DTE Electric's coal, gas, and renewable plants
13 are mechanically available to produce power. The 2023 Target is 81.8%.

14 2) Nuclear On-Line Reliability Loss Factor (ORLF), which is energy
15 generation losses corrected for refueling outage losses and exempt
16 activities. The 2023 ORLF Target is 1.03%.

17

18 **Q71. What are the operating measures applicable to the Nuclear Generation**
19 **business unit?**

20 A71. Nuclear Generation has four Safety and Engagement related measures and four
21 Operating Excellence measures, discussed below in further detail.

22

23 **Q72. What are Nuclear Generation's Safety and Engagement related measures?**

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1 A72. In addition to Employee Engagement, as measured by Gallup surveys, and the
2 OSHA Recordable Incident Rate, as described above, Nuclear Generation also has
3 two additional safety measures.

4 1) The first is the annual Total Industrial Safety Accident Events (TISA
5 Events), which is a nuclear industry measure that is aligned with the
6 Institute of Nuclear Power Operations (INPO). The Target is zero incidents
7 in any calendar year quarter.

8 2) The second relates to On-Line Radiation Exposure, which is designed to
9 maintain a focus on the safety of personnel. The 2023 Target is 50.6 Rem,
10 which is a standard unit of measure of exposure to radiation.

11

12 **Q73. What are the Operating Excellence measures related to Nuclear Generation?**

13 A73. Nuclear Generation has four Operating Excellence measures.

14 1) The first relates to On-Line Reliability Loss Factor, as described above.

15 2) The second measure regarding Operational focus pertains to a group of 11
16 measures that relate to Fermi 2 plant performance. The 2023 Target is 93.4.

17 3) The third measure is an index of Annualized Work Management, which
18 consists of 10 individual indicators. The 2023 Target is 99.8.

19 4) The final Nuclear Generation measure relates to the Nuclear Refuel Outage
20 Milestone, which is a measure of the effective planning and preparation for
21 refueling planned in 2024. The Target for 2023 is that 30 milestones are
22 achieved at 98% performance and four are achieved with performance
23 between 96% and 98%.

24

25 **Q74. Are there other AIPs and REPs that impact DTE Electric's expenses?**

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1 A74. Yes. In addition to the DTE Electric and Nuclear Generation measures described
2 above, there are also AIPs and REPs in place for corporate staff employees at DTE
3 LLC that provide services to all DTE Energy business units, including DTE
4 Electric. The DTE LLC measures reflect certain DTE Electric and Nuclear
5 Generation measures, as well as measures related to DTE Gas. The specific DTE
6 LLC measures and weightings related to DTE Electric and Nuclear Generation are
7 reflected on Exhibit A-21, Schedule K-4.

8

9 **Q75. What is the Company's Long-Term Incentive Plan?**

10 A75. The LTIP provides the opportunity for certain individuals to receive retention-
11 oriented or performance-based rewards delivered via shares of DTE Energy
12 common stock, either Performance Shares, which are based on the achievement of
13 multi-year performance objectives, or through Restricted Stock. Currently, 70%
14 of the value of awards for executives and directors is through grants of
15 Performance Shares and 30% of the value of awards is through Restricted Stock,
16 while 100% of the awards to other eligible employees are through Performance
17 Shares. The objective in granting shares through this program is to both motivate
18 superior results as well as provide a means to retain key employees and is
19 consistent with the practices of most companies, as reflected in the WorlDatWork
20 and Compensation Advisory Partners survey, referenced in Q57 above.

21

22 **Q76. What are the performance share measures used in the 2023 LTIP?**

23 A76. The measures are shown on Exhibit A-21, Schedule K5.

24

25 **Q77. What is the rationale for the use of these measures?**

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1 A77. These measures generally reflect the long-term financial performance of DTE
2 Energy and are intended to motivate employees of the individual operating
3 companies, such as DTE Electric, to keep in mind the role of their own
4 contributions to the overall long-term success of DTE. Accordingly, the
5 predominate measure for DTE Electric and DTE LLC (80% for both) is the total
6 return to DTE Energy shareholders (i.e., capital appreciation and dividends)
7 relative to a group of peer companies over the next three years. The second
8 financial measure included in the LTIP, which contributes 20% to the total
9 weighting, is DTE Energy's three-year cumulative Operating Earnings per Share.
10 The three-year focus of the performance-based measures is designed to motivate
11 decisions and actions that produce sustainable benefits rather than short-term
12 actions that may entail long-term risks.

13

14 **Q78. What is the basis for the costs of the LTIP?**

15 A78. The LTIP costs incurred in 2022 pertain to the grants of Performance Shares and
16 Restricted Stock. The expense related to the Restricted Stock is not conditioned
17 on any Company performance measures but rather is exclusively based on the
18 number of shares granted at the date of grant. In contrast, Performance Shares
19 expense is based on the achievement of the predetermined performance objectives.
20 The recognized cost of Performance Shares is based on the number of shares
21 granted at the market price of DTE Energy's common stock at the date of grant
22 but with adjustment in the number of shares based on actual performance. The
23 Performance Shares expense included in Table 3 is based on Target performance.

24

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1 **Q79. What is the incentive compensation expense if the Company achieves all of its**
2 **Financial and Operating Targets?**

3 A79. The net expense to DTE Electric in the projected test period of the Company
4 achieving all its Targets for the incentive compensation plans, exclusive of the
5 expense related to the Top Five Executive Officers, is \$59.504 million. The table
6 below summarizes the expense for the projected test period by the nature of the
7 plans, the classification of the employees eligible and the basis of the metrics used.

Table 3

	<u>LTIP</u>	<u>AIP</u>	<u>REP</u>	<u>Total</u>
	(000's Omitted)			
Financial				
DTE Electric	\$5,858	\$615	\$7,029	\$13,502
Nuclear Gen	1,395	92	839	2,326
DTE LLC	13,154	3,509	6,741	23,404
	20,408	4,215	14,609	39,232
Operating				
DTE Electric	0	504	5,758	6,262
Nuclear Gen	0	200	2,527	2,727
DTE LLC	0	3,862	7,420	11,281
	0	4,566	15,705	20,271
Total				
DTE Electric	5,858	1,119	12,787	19,764
Nuclear Gen	1,395	292	3,367	5,054
DTE LLC	13,154	7,370	14,161	34,686
	\$20,408	\$8,781	\$30,315	\$59,504

10

11 **Q80. Why are the expenses for DTE LLC most of the incentive compensation**
12 **expenses?**

13 A80. DTE LLC provides a variety of administrative and other services that are common
14 to both DTE Electric and DTE Gas for which the costs are billed to the operating

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1 companies, as explained by Witness Uzenski. In addition, DTE LLC employs all
2 the Executives of DTE Energy, including the Officers of DTE Electric.

3

4 **Q81. How have you reflected the Operating Excellence measures related to DTE**
5 **Gas in the AIP and REP for DTE LLC?**

6 A81. While the AIP and REP expenses allocated to DTE Electric in the historic period
7 from DTE LLC include some measures related to DTE Gas, the AIP and REP
8 weightings for DTE LLC have been adjusted to exclude the measures specifically
9 related to DTE Gas.

10

11 **Q82. Are all incentive compensation costs dependent on the Company's financial or**
12 **operating performance?**

13 A82. No. As described earlier, a portion of the DTE Energy shares granted under the
14 LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the
15 expense of Restricted Stock is not variable based on either the Company's
16 financial or operating performance. The only contingency is that the employee
17 forfeits the Restricted Stock if they leave the Company, other than through
18 retirement or the event of the employee's death or disability.

19

20 **Q83. How does the lack of variability in the LTIP expense affect its treatment in**
21 **your analysis of incentive compensation?**

22 A83. Although Restricted Stock grants are made under the LTIP, the ultimate payouts
23 are not dependent on future Company or employee performance, and therefore,
24 Restricted Stock is not regarded as an element of the Company's incentive

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1 compensation expense. Accordingly, the projected test year Restricted Stock
2 expense of \$8.960 million has been excluded from Table 3 above.

3

4 **Q84. Has the Commission provided any criteria for the inclusion of incentive**
5 **compensation expense in the Company's revenue requirements?**

6 A84. Yes. The Commission has indicated in all its recent Orders addressing incentive
7 compensation programs that inclusion of incentive compensation expense in a
8 company's revenue requirement was dependent on a showing that the incentive
9 compensation programs provided benefits to customers in excess of the expense.

10

11 **Q85. Has the Company performed an analysis of the customer benefits of the**
12 **Company's incentive compensation plans?**

13 A85. Yes. The Company has performed a comprehensive analysis of the customer
14 benefits that would be derived from the achievement of the financial and operating
15 metrics included in the Company's short and long-term incentive plans relative to
16 their expense. This analysis, as reflected on Exhibit A-21, Schedule K6,
17 demonstrates that the calculated aggregate benefit of \$104.478 million exceeds the
18 total incentive compensation expense of \$59.504 million by \$44.974 million.

19

20 **Q86. How did you calculate the benefits of the Financial measures?**

21 A86. While the Company has not quantified the benefits to customers of each of the
22 financial measures, one measure that had specifically quantifiable benefits is the
23 Cash Flow from Operations measure within the AIP and REP, as reflected on line
24 8 of Exhibit A-21, Schedule K6. This measure is focused on the Company
25 maintaining its "A" debt rating from Standard & Poor's and comparable ratings by

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1 the other major debt rating firms. The yield spread between utility bonds for bonds
2 with an “A” rating compared to “BBB” rated bonds is 23 basis points. Based on
3 the long-term debt balances included in the capital structure sponsored by Company
4 Witness Vangilder, a downgrade in the Company’s credit rating would increase the
5 Company’s annual interest costs by \$19.9 million.

6

7 **Q87. How are the benefits of the Company achieving Target performance for the**
8 **Operating measures reflected on Exhibit A-21, Schedule K6 determined?**

9 A87. The benefits of the Operating measures are computed based either on the avoided
10 costs to the Company, which results in lower future revenue requirements, or
11 based on the value to customers of improved performance. The reference points
12 to determine improvement are, in most instances, based on the Company’s actual
13 performance in the 2022 historical test year, but when 2022 results are not
14 representative, either an historical average or a comparison to external peer groups
15 is used. In those instances, in which the Company’s Targets are based on superior
16 performance relative to peers, then measures of peer performance are used. The
17 benefits of achieving Target performance are allocated between the AIP and REP
18 components based on the relative incentive compensation expense for each
19 measure.

20

21 **Q88. How did you quantify the benefit of achieving Target performance levels in**
22 **the Customer Satisfaction measures?**

23 A88. The benefits of achieving the 2023 Target of 39 Net Promoter Score (NPS) are
24 based on the expectation that improvements in the NPS score will result in fewer

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1 customer calls. The 2023 Target of 39 is expected to produce \$2.2 million of
2 customer benefits based on avoided Company costs and customer costs.

3

4 The customer benefits of attaining Target performance for MPSC Customer
5 Complaints measure is based on the avoided costs to both the Company and its
6 customers due to the reduced time spent by employees and customers resolving
7 complaints for a total savings of \$29,000.

8

9 While the total quantified benefits related to the Customer Satisfaction measures
10 are less than the related expense, there can be little doubt that an emphasis among
11 the Company's employees on improving the experiences customers have with the
12 Company results in additional significant non-quantifiable benefits to both
13 customers and the Commission.

14

15 **Q89. How did you determine the benefits of the Employee Engagement measure?**

16 A89. The quantifiable benefits of a highly engaged workforce are based on three critical
17 dimensions identified by Gallup: absenteeism, productivity, and safety incidents.
18 According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1%
19 reduction in absenteeism, a 1.8% increase in productivity, and a 3.8% reduction in
20 safety incidents. Compared to the 80th percentile of Gallup survey results for all
21 companies included in Gallup's database, the achievement of the 2023 Target
22 Gallup Target will generate O&M savings of \$11.9 million, which is attributed
23 exclusively to the AIP because the Employee Engagement measure is not included
24 in the REP.

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1 **Q90. What are the expected benefits of the Company achieving Target level**
2 **performance regarding the OSHA Recordable Incident Rate (RIR)?**

3 A90. The benefits of achieving the OSHA Recordable Incident Rate (RIR), and the
4 Nuclear Total Industrial Safety Accident Rate goal, are based on the estimated
5 direct costs of non-fatal incidents of \$50,000, as developed by OSHA, as adjusted
6 for inflation through 2022, and a study by Liberty Mutual that estimates the
7 indirect cost of an OSHA recordable incident is about 3.0 times the direct costs,
8 resulting in an estimated total cost of \$201,000 per incident, in current dollars.
9 Based on Target level performance, relative to the Company's five-year average
10 results in an estimated benefit of \$2.6 million net of the savings capitalized. The
11 benefits of achieving the OSHA RIR Target are allocated to all the other safety
12 measures in proportion to the costs of each measure, as reflected on lines 29
13 through 35 of Exhibit A-21, Schedule K6.

14

15 While the quantified savings of the safety related metrics are less than the related
16 costs, much like the customer service-related measures, the benefits of maintaining
17 an organizational focus on the safe operation of the Company's system for the
18 benefit of its employees, customers, and the communities where the Company
19 operates are undoubtedly substantial.

20

21 **Q91. How did you quantify the savings related to improvements in distribution**
22 **system reliability?**

23 A91. The benefit of achieving the SAIDI excluding MEDs Target is based on comparing
24 the 2023 Target of 150 minutes to the five year average of SAIDI excluding MEDs
25 of 161 minutes, which represents a reduction of 11 minutes. The derivation of the

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1 benefits to customers is based on the Interruptions Cost Estimation Calculator as
2 developed by Nexant, Inc. and the Lawrence Berkeley National Lab. A reduction
3 of eleven minutes in the SAIDI excluding MEDs produces an annual customer
4 benefit of \$43.1 million. The benefits of achieving Target performance in the
5 SAIDI excluding MEDs measure have been allocated equally between the SAIDI
6 exclusive of MEDs measures and CEMI4 Percent of Customers measure due to
7 the close relationship of each of these measures to distribution system reliability,
8 as reflected on lines 40 and 42 of Exhibit A-21, Schedule K6.

9

10 **Q92. Have you quantified the benefits of the Generation Availability measure?**

11 A92. The 2023 Generation Availability Target of 81.8% reflects a modest increase from
12 the four-year average of actual Generation availability of 81.7%. Accordingly, I
13 have not quantified the customer benefits of the increase in Generation Availability.

14

15 **Q93. What are the benefits of an increase in the Nuclear On-Line Reliability Loss**
16 **Factor?**

17 A93. The benefits of an increase in the Nuclear Power Plant Reliability reflect an increase
18 from the On-Line Reliability Loss Factor at Fermi 2 from the five-year average of
19 4.39% to the 2023 Target of 1.03%. The savings computed are based on the
20 differential between Fermi 2's marginal fuel costs and the average market price of
21 avoided energy purchases combined with value of increased capacity for a total
22 annual savings of \$24.7 million. These savings are allocated to the Nuclear related
23 operating measures included in the AIP and REP in proportion to the costs of each
24 measure. Specifically, \$19.0 million is assigned to Nuclear On-Line Reliability

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1 Loss Factor measure and \$1.9 million is assigned to each of the three other Nuclear
2 related measures, as reflected on lines 46 through 52 of Exhibit A-21, Schedule K6.

3

4 **Q94. Have you quantified any additional savings related to the other Nuclear**
5 **Generation measures included in the AIP and REP?**

6 A94. No. The Nuclear On-Line Reliability Loss Factor measure represents the only
7 quantifiable benefits of the Company meeting its Target performance levels for
8 Fermi 2. While there is indisputable value in the various specific measures within
9 the other Nuclear measures, the benefits of Fermi 2 achieving its On-Line
10 Reliability Loss Factor Target has been attributed to the other AIP and REP
11 Nuclear Operating Excellence measures.

12

13 **Q95. What is your conclusion regarding the cost effectiveness of the Company's**
14 **incentive compensation plans?**

15 A95. As reflected on Exhibit A-21, Schedule K6, it is clear the quantified customer
16 benefits of the Company achieving Target performance levels are substantially
17 greater than the related expense.

18

19 Because the Company's overall employee compensation approximates the market,
20 inclusive of incentive compensation and the quantified benefits exceed the
21 projected incentive compensation expense, the Company's total incentive
22 compensation expense should be included in the revenue requirement adopted by
23 the Commission in this proceeding as a reasonable and prudently incurred expense.

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- 1 **Q96. Does this complete your direct testimony?**
- 2 A96. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

MATTHEW A. FIX

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MATTHEW A. FIX

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

3 A1. My name is Matthew A. Fix (he/him/his). My business address is DTE Energy
4 Company, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE
5 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
6 Company (DTE Energy).

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. My testimony will rebut the testimony of several witnesses, including:

- 15 • Attorney General (AG) Witness Coppola's proposal to exclude incentive
16 compensation expense related to 53% of the operating measures and
17 Association of Businesses Advocating Tariff Equity (ABATE) Witness
18 York's proposal to exclude incentive compensation expense related to
19 certain operating measures,
- 20 • Staff Witness Rueckert's proposed adjustment to the Company's projected
21 Employee Savings Plan expense,
- 22 • AG Witness Coppola's proposal to exclude the expense related to the
23 Supplemental Savings Plan, and
- 24 • AG Witness Coppola's proposal to include \$10.1 million of the potential
25 savings arising from the Company's 2024 Voluntary Separation Incentive

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1 Program (VSIP) as a reduction to the Company's total projected Operation
2 and Maintenance (O&M) expense. Also, I will rebut the Citizen Utility
3 Board of Michigan, Michigan Environmental Council and Natural Resource
4 Defense Council, collectively referred to as CUB, Witness Denzler's
5 proposal to include \$34.2 million of estimated gross savings from the VSIP
6 as a reduction to the Company's O&M expense.

7 The absence of a discussion of other matters in my testimony should not be
8 regarded as an indication that I agree with all other aspects of the Staff's and
9 intervenor's testimony. The narrow focus of my testimony is instead a consequence
10 of a focus on priority issues in recognition of the available resources.

11

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

13 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-35	Z1	AIP/REP 2018-2023 Performance Weighted Results
16	A-35	Z2	Employee Savings Plan Expense: Updated Staff
17	A-36	AA5	Benefits Adjustments: Summary

18

19 **Q5. Were these exhibits prepared by you or under your direction?**

20 A5. Yes, they were.

21

22 **Incentive Compensation**

23 **Q6. What is AG Witness Coppola's proposal regarding the Company's incentive**
24 **compensation expense?**

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1 A6. Witness Coppola proposes the exclusion of 52.6% of the Company's projected
2 Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP) expense
3 related to operating measures of \$20.271 million, which results in a disallowance
4 of \$10.663 million (Coppola Direct, page 123, lines 4-9).

5
6 **Q7. What is the basis for Witness Coppola's proposal to exclude 52.6% of the**
7 **incentive compensation expense related to Operating measures?**

8 A7. Witness Coppola relies on his analysis of the operating performance levels achieved
9 for the years 2019 through 2023 to conclude that 47.4% of these measures achieved
10 performance levels of Target or higher for both AIP and REP for all employee
11 groups, as reflected on Exhibit AG-21.

12
13 **Q8. Do you agree with Witness Coppola's analysis of historical operating**
14 **performance measures?**

15 A8. No. Witness Coppola's analysis of the proportion of measures that were at Target
16 or above is flawed because it fails to recognize how AIP and REP are designed.
17 While certain measures may produce results that are less than Target, other
18 measures can produce results that are greater than Target. Moreover, even those
19 measures where actual performance was less than Target can still generate payouts
20 if the actual performance was higher than the Threshold level. Under the AIP,
21 payouts range from 25% for Threshold performance to 175% for Maximum
22 performance for non-executives, and up to 200% for executives, with 100% payouts
23 for Target performance. Payouts under the REP range from 50% for Threshold
24 performance to 150% for Maximum performance, with 100% payouts for Target
25 performance. Thus, if the actual performance is less than Target but higher than

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1 Threshold, payouts under the AIP would range between 25% and 100% and the
2 REP payouts would range between 50% and 100%.

3

4 These ranges in potential payouts result in Witness Coppola's singular focus on
5 whether actual performance was at Target or above or below Target being an
6 inaccurate representation of the impact of performance on actual payouts. For
7 example, in 2019 the Customer Satisfaction Improvement Program that measures
8 the Defects Per Million Opportunities (DPMO) had a Target of 65,645 with actual
9 results of 65,794, which produced a 96.9% AIP payout and a 97.9% REP payout.
10 Had the DPMO actual results in 2019 been only 149 lower the Company would
11 have achieved Target level performance, which represents a variance from Target
12 of only 0.2%. In contrast, Witness Coppola's approach would deem DPMO results
13 of only 0.2% less than Target to result in a zero payout. This is an unreasonable
14 inference and is inconsistent with the design of the plans. Similarly, Witness
15 Coppola's method ignores the impact of performance above Target, which could
16 result in payouts of up to 150% for the REP and up to 200% for the AIP when
17 Maximum performance levels are achieved. Witness Coppola's exclusive reliance
18 on the achievement of performance relative to Target levels fails to recognize the
19 gradients of performance between Threshold and Maximum performance levels
20 that are the basis for actual payouts.

21

22 **Q9. Have you computed the actual operating performance levels for the same**
23 **period that recognizes the gradients of performance between Threshold and**
24 **Maximum levels?**

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1 A9. Yes. Exhibit A-35, Schedule Z1, shows that actual weighted performance for the
2 last five years was 79.3% for the AIP, 81.5% for the AIP Executives, and 69.2%
3 for the REP for a combined average of 76.7%.

4

5 **Q10. Is the use of average annual performance, as reflected on Exhibit A-35,**
6 **Schedule Z1, a more accurate depiction of the Company's historical**
7 **performance than the method used by Witness Coppola on Exhibit AG-49?**

8 A10. Yes. The average annual performance method reflected on Exhibit A-35, Schedule
9 Z1 is a more accurate method of measuring historic performance than the approach
10 used by Witness Coppola. Witness Coppola's approach is based on a simplistic
11 binary model, wherein either Target performance was or was not met. Whereas the
12 methodology reflected on Exhibit A-35, Schedule Z1, recognizes that actual
13 payouts can fall within a wide spectrum of performance levels, consistent with the
14 design of the program.

15

16 **Q11. Is it reasonable to assume that only 47.4% of the operating performance**
17 **measures will be achieved in the projected test year?**

18 A11. No. The establishment of costs to be reflected in the Company's revenue
19 requirement is subject to various uncertainties, but the goal is to establish expenses
20 at the levels that are most likely to be incurred. In this instance, it is reasonable to
21 assume that the Company will, on an overall basis, achieve Target performance
22 levels for both the AIP and REP and include all incentive compensation expense
23 related to the operating measures.

24

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1 **Q12. What is ABATE Witness York’s proposal regarding incentive compensation**
2 **expense related to the Operating measures?**

3 A12. ABATE Witness York proposes that the incentive compensation expense related to
4 the Operating measures that don’t have a measurable net customer benefit, to wit:
5 the Customer Satisfaction and Safety measures, be excluded. Additionally,
6 Witness York proposes the expense related to SAIDI excluding MEDs and CEMI4
7 be excluded due to the “Company’s recent failure to meet its reliability goals, as
8 well as its track record of historic revenue sufficiency amounts”. (York Direct,
9 page 16, lines 8-22 and page 17, lines 1-13).

10

11 **Q13. Do you agree with ABATE Witness York’s proposal regarding the exclusion**
12 **of incentive compensation expense related to the Customer Satisfaction and**
13 **Safety measures?**

14 A13. No. ABATE Witness York’s proposal is flawed for two reasons. First, ABATE
15 Witness York’s proposal seems to rely on the flawed premise that all of the benefits
16 of the individual measures are capable of precise quantification. Second, ABATE
17 Witness York’s proposal represents an unreasonable interpretation and application
18 of the Commission’s standard that incentive compensation expense is only
19 recoverable if the benefits of the incentive compensation plans exceed the related
20 costs. Company Witness Foley addresses why the second rationale is improper.

21

22 **Q14. What is the flaw in ABATE Witness York’s apparent assumption that all the**
23 **individual incentive compensation measures are capable of precise**
24 **quantification?**

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1 A14. The Cost/Benefit analysis reflected on Exhibit A-21 Schedule K6 represents only
2 the reasonably quantified financial benefits of the Company achieving Target
3 performance for each of the measures included in the incentive compensation plans.
4 However, some of the measures provide benefits beyond those able to be precisely
5 quantified. For example, while the quantifiable benefits of the MPSC Customer
6 Complaints measure only amount to \$29,000, which represents the savings from a
7 reduction in time spent by customers and Company employees by the Company
8 achieving Target performance, this doesn't capture the unquantifiable benefits to
9 customers such as the time and frustration leading up to the complaint with the
10 MPSC. Moreover, the benefits also exclude any quantification of the savings
11 realized by the Commission from a reduction in customer complaints. It is clear
12 that the total benefits, both quantified and unquantified, of the Company achieving
13 Target performance in a key customer satisfaction measure would exceed the \$2.3
14 million of expense.

15 Similarly, the benefits of the Company achieving its Net Promoter Score only
16 reflects the benefits of reductions in customer calls and assigns no measurable value
17 to the benefits to customers that may otherwise be inconvenienced by the
18 Company's service levels.

19 In addition, while the quantified benefits of the Company achieving its Target
20 performance for the Safety measures is \$2.585 million, this reflects only the
21 measurable benefits to the Company of improved safety performance and excludes
22 any impact on the communities the Company serves. Further, because it would be
23 callous to assign any value to fatalities, the measure of the benefits specifically
24 excludes the immeasurable benefits of avoided fatalities.

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1 In summary, ABATE Witness York argues that only measurable benefits should be
2 the basis of determining the net customer benefits of the Company achieving its
3 Operating Targets, which is improper because it presumes that all the benefits of
4 the measures are precisely quantifiable, which they are not. The absence of
5 quantification does not imply the benefits are non-existent.

6

7 **Q15. Why is ABATE Witness York's interpretation and application of the**
8 **Commission's incentive compensation Cost/Benefit test requirement**
9 **unreasonable?**

10 A15. The origins of the Commission's policies regarding the recoverability of incentive
11 compensation can be traced back to its Order in Case No. U-10150, wherein the
12 Commission concluded:

13

14 "It further finds that the utility should be placed on notice that
15 future approval of an incentive bonus like this requires a
16 showing that it will not result in excessive costs and the benefits
17 to the utility's ratepayers will be commensurate with those
18 costs." (Order, Case No. U-10150, pages 57-58)

19

20 The Commission has consistently applied the standard articulated in the Order in
21 Case No. U-10150 and assessed the net customer benefits on an aggregate basis
22 without regard to the net benefits for each measure. ABATE Witness York's
23 proposal to only allow recoverability based on each component is unreasonable
24 because it relies only on measurable benefits and is inconsistent with the
25 Commission's traditional practice without any explanation as why a change in
26 practice is either necessary or desirable.

27

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1 **Q16. Is ABATE Witness York's proposal to exclude the incentive compensation**
2 **expense related to SAIDI excluding MEDs and CEMI4 based on recent**
3 **performance appropriate?**

4 A16. No. ABATE Witness York's proposal appears to assume that if the Company does
5 not achieve Target performance levels there will not be any payout under the
6 incentive compensation plans, which is incorrect. As described regarding AG
7 Witness Coppola's proposal, any payouts are based on a range of actual
8 performance between Threshold and Maximum levels. So, while ABATE Witness
9 York observes that the Company's actual 2023 SAIDI excluding MEDs was 157
10 minutes compared to the 2023 Target of 150 minutes, the Company still had
11 payouts under its plans. That is, because the Threshold performance level for
12 SAIDI excluding MEDs was 180 minutes, for AIP the Company paid out 82.5% of
13 Target and for REP the Company paid out 88.3% of Target. ABATE Witness
14 York's singular focus on 2023 results is also misplaced. While the Company's
15 CEMI4 performance level was less than Target in 2023, the Company's 2022
16 CEMI4 performance was above Target. It is unreasonable to rely on one year's
17 performance to assess the probability of the Company achieving its Targets in the
18 projected test year.

19

20 **Employee Savings Plan**

21 **Q17. What adjustment did Staff Witness Rueckert propose to the Company's projected**
22 **Employee Savings Plan expense?**

23 A17. Staff Witness Rueckert used the Company's 2023 Employee Savings Plan (ESP)
24 expense of \$27.286 million and escalated by 4.06% annually based on a five-year
25 average of the annual change in the Company's ESP costs for the years 2018

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1 through 2023 resulting in a projected ESP expense of \$29.547 million (Rueckert
2 Revised Direct, page 7, lines 11-15).

3

4 **Q18. Do you agree with Staff Witness Rueckert's proposed adjustment to the**
5 **Company's projected ESP expense?**

6 A18. No. Staff Witness Rueckert's use of the Company's 2023 ESP expense as a starting
7 point is improper because the Company capitalized an abnormally high proportion
8 of ESP costs in 2023, as explained by Company Witness Uzenski in response to
9 Question 31 of her Rebuttal Testimony.

10

11 **Q19. Have you prepared an alternative analysis of the Company's Employee**
12 **Savings Plan expense?**

13 A19. Yes. Exhibit A-35, Schedule Z2 reflects an update of Staff Exhibit S-15.4 that
14 includes a calculation of the impact of the change in the proportion of the total
15 Employee Savings costs capitalized in 2023. Use of the 2022 percentage of ESP
16 expensed of 60.4% rather than the 2023 percentage of ESP expensed of 54.6%
17 increases the Company's 2023 ESP expense by \$2.901 million (60.4%-54.6% X
18 \$50.018 million).

19

20 **Q20. Did Staff Witness Rueckert use the 2023 percentage of benefits costs expensed**
21 **for all of his projected benefits expense?**

22 A20. No. Staff Witness Rueckert appropriately used the 2022 percentage of Active
23 Healthcare costs expensed of 60.4% in the development of projected Active
24 Healthcare expense, as reflected on Exhibit S-14.3, column (f), line 5.

25

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1 **Q21. What is your adjustment to Staff Witness Rueckert's projected Employee**
2 **Savings Plan expense?**

3 A21. Exhibit A-36, Schedule AA5 reflects the calculation of my adjustment to Staff
4 Witness Rueckert's proposed ESP Plan expense. The adjusted 2023 ESP expense
5 is escalated by the five-year average percentage increase in the Company's ESP
6 costs of 4.06% to develop the ESP expense for 2025 of \$32.688 million, which
7 represents a \$3.141 million increase to Staff Witness Rueckert's ESP projection of
8 \$29.547 million.

9

10 **Supplemental Savings Plan**

11 **Q22. What adjustment did AG Witness Coppola make to the Company's projected**
12 **Supplemental Savings Plan expense?**

13 A22. Witness Coppola proposes the elimination of the expense related to the
14 Supplemental Savings Plan (SSP).

15

16 **Q23. What was the basis for Witness Coppola's elimination of the SSP expenses?**

17 A23. Witness Coppola characterized the costs as being "for a limited number of highly
18 paid employees" and referenced the Commission's elimination of the costs of the
19 Company's Supplemental Employee Retirement Plan (SERP)" (Coppola Direct,
20 page 114, lines 6-9).

21

22 **Q24. What is the SSP?**

23 A24. As I describe in my Direct testimony (page 13, lines 7-19), the SSP is a "make-
24 whole" plan that allows employees whose annual earnings or contributions exceed
25 the limits prescribed by the Internal Revenue Service (IRS) to continue to accrue

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1 benefits that are identical to the benefits they would have accrued in the qualified
2 Employee Savings Plan.

3

4 **Q25. Does the Company offer any non-qualified pension plans?**

5 A25. Yes. The Company offers two non-qualified pension plans. Specifically, the
6 Company provides the Executive Supplemental Retirement Plan (ESRP) and the
7 Supplemental Retirement Plan (SRP). The Commission has consistently excluded
8 the cost of these non-qualified pension plans from the Company's revenue
9 requirements. I presume that AG Witness Coppola's reference to a "SERP" is a
10 reference to these non-qualified pension plans.

11

12 **Q26. Do you agree with Witness Coppola's recommendation?**

13 A26. No. Witness Coppola's proposed exclusion of the SSP expenses is apparently
14 based on his conclusion that it represents a benefit only available to a limited
15 number of highly compensated employees overlooks the fact that the benefits
16 provided through the SSP are exactly the same as those provided within the
17 Company's Qualified Savings Plan.

18

19 **Q27. Has the Commission addressed the issue of the SSP in prior cases?**

20 A27. Yes. The Commission has rejected proposals to disallow the SSP expense in its
21 Orders in Case Nos. U-15244 and U-18255. Specifically, in its Order in Case No.
22 U-18255 the Commission rejected a Staff proposal to disallow the SSP costs based
23 on the Commission's disallowance of non-qualified pension costs in its Order in
24 Case No. U-18014. Instead, the Commission concluded that the precedent of the
25 Order in Case No. U-18255, which allowed recovery of the SSP costs, was more

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1 pertinent than Staff's reliance on the disallowance of non-qualified pensions costs.
2 The circumstances that allowed for a different treatment between the SSP and the
3 non-qualified pension plans in that case have not changed.

4

5 **Q28. What is your recommendation regarding AG Witness Coppola's exclusion of**
6 **the SSP expense?**

7 A28. I recommend the Commission reject AG Witness Coppola's exclusion of \$3.207
8 million of SSP expense because it is a reasonable expense consistent with the
9 Company's qualified ESP and its inclusion in the Company's revenue requirement
10 is consistent with Commission practice.

11

12 **Voluntary Incentive Separation Program (VSIP)**

13 **Q29. What adjustment does AG Witness Coppola propose regarding the Company's**
14 **2024 VSIP?**

15 A29. AG Witness Coppola proposes to reduce the Company's total O&M expense by
16 \$10.1 million, which purports to represent half of the Company's projection of \$20.3
17 million of estimated savings in 2025 (Coppola Direct, page 105, lines 1-9).

18

19 **Q30. Do you agree with AG Witness Coppola's proposal?**

20 A30. No. It is premature to include any savings from the VSIP in the Company's revenue
21 requirement. The purpose of the VSIP was to realign the workforce to support the
22 changing nature of the Company's work and how the work is done, including an
23 increased focus on infrastructure investments, cybersecurity, and the clean energy
24 transition. Therefore, the Company continues to assess the need to fill key positions
25 which will impact any actual savings that may potentially be realized in 2025. While
26 the Company has made certain assumptions about the number of open positions as

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1 a result of the VSIP that will be filled in its estimated savings, these estimated
2 savings will continue to evolve as decisions regarding the actual number of positions
3 filled are made throughout the remainder of 2024. Rather than relying on an estimate
4 of potential savings that may be created by the VSIP, it is more prudent to wait until
5 any savings are actually realized which can then be reflected in the Company's
6 future revenue requirements.

7

8 **Q31. Does AG Witness Coppola's recommendation to include the estimated VSIP**
9 **savings as a reduction to the Company's revenue requirement reflect the costs**
10 **incurred by the Company in 2024 related to the VSIP?**

11 A31. No. Because the Company has not sought to recover the \$30.6 million in costs
12 related to the separation payments accrued in 2024, it would be unreasonable to
13 include a reduction to the Company's total O&M expense of the estimated savings
14 without any recognition of the costs incurred by the Company.

15

16 **Q32. What is CUB Witness Denzler's proposal regarding the VSIP?**

17 A32. CUB Witness Denzler proposes that all of the estimated gross savings related to the
18 VSIP of \$34.2 million be reflected as a reduction to the Company's O&M for the
19 projected test year (Denzler Direct, page. 14, lines 2-4). That is, CUB Witness
20 Denzler proposes that the labor and related savings of the employees that departed
21 under the VSIP be reflected, but not the estimated costs of the employees that will
22 be required to fill key positions.

23

24 **Q33. Is CUB Witness Denzler's proposal to include \$34.2 million of the estimated**
25 **VSIP savings as reduction to the Company's revenue requirement in this case**
26 **reasonable?**

Line
No.

1 A33. No. As I explained relative to AG Witness Coppola's proposal to reflect the
2 estimated VSIP savings, it is simply premature to reflect any savings from the VSIP
3 because of the preliminary nature of the estimate. While AG Witness Coppola
4 correctly reflected the cost of new hires in his estimate of new savings, CUB
5 Witness Denzler proposes to include all of the estimated gross savings and excluded
6 any estimated costs for newly hired employees.

7
8 **Q34. What is the basis for CUB Witness Denzler's proposal to exclude the costs of**
9 **newly hired employees for those that departed under the VSIP?**

10 A34. CUB Witness Denzler claims that it is unreasonable for the Company's "rate payers
11 to bear the risk for the volatility of its staffing levels" (Denzler Direct, page 13,
12 lines 14-15).

13
14 **Q35. Do you agree with CUB Witness Denzler's proposal?**

15 A35. No. First, CUB Witness Denzler has seemingly assumed that the impetus of the
16 Company offering the VSIP was solely to reduce costs, as opposed to supporting
17 the Company's realignment of its workforce to meet changing needs, as I explained
18 relative to AG Witness Coppola's proposal. Second, while the precise number and
19 cost of employees required to meet the Company's changing workforce needs
20 continues to develop, it is patently unreasonable to assume the level of employees
21 hired between June 2024 and 2025 will be zero.

22
23 **Q36. Why is it unreasonable to assume that the Company will not fill any of the**
24 **positions vacated as a result of the VSIP?**

Line
No.

1 A36. As reflected on Confidential Exhibit CUB-14C, 389 employees left the Company
2 in connection with the VSIP in the departments affected by the VSIP. In April
3 2024, it was expected that the Company would need to hire 184 new employees to
4 fill positions consistent with the realignment of the Company's workforce, as
5 described in my discussion of AG Witness Coppola's proposal. Plus, new
6 employees will continue to be added within the Company to meet changing
7 requirements, such as related to the execution of new major projects, which were
8 not reflected in the costs of the Company's new hires on Confidential Exhibit CUB-
9 14C. As the Company's workforce needs evolve during the remainder of 2024 and
10 2025, the Company will continue to add new employees to meet its requirements.
11 CUB Witness Denzler's dismissal of the Company's estimated costs of the new
12 hires based on the fact that the precise amount is uncertain ignores the dynamics of
13 on-going changes in the Company's workforce. While the hiring projections
14 included in Confidential Exhibit CUB-14C are preliminary and continue to evolve,
15 they represent the best estimate currently available.

16

17 **Q37. Are the Company's customers incurring any additional costs as a result of the**
18 **VSIP?**

19 A37. No. As explained in relation to my discussion of AG Witness Coppola's VSIP
20 proposal, the Company incurred \$30.6 million of costs in 2024 to implement the
21 VSIP but has not sought to recover that cost in its rates. Therefore, CUB Witness
22 Denzler's proposal to reflect the gross estimated savings from the VSIP while
23 ignoring both the costs to achieve incurred by the Company in 2024 and the
24 estimated costs to hire new employees would result in customers realizing all of the
25 savings of VSIP and none of the related expenses. This is clearly unreasonable.

Line
No.

- 1 **Q38. Does this conclude your rebuttal testimony?**
- 2 A38. Yes, it does.

1 JUDGE WALLACE: Please continue.

2 MS. REITZEL: Thank you, your Honor. DTE
3 now moves to bind into the record the Direct Testimony of
4 Jerome K. Hooper, which consists of a cover sheet and 26
5 pages of questions and answers, and for the admission of
6 five direct exhibits and schedules that Mr. Hooper either
7 sponsored or cosponsored, designated as Exhibit A-13
8 Schedule C5.11, Revised Exhibit A-13 Schedule C5.11.1,
9 Revised Exhibit A-13 Schedule C5.11.2, Exhibit A-13
10 Schedule C5.11.3, and Exhibit A-13 Schedule C5.12.2.
11 Mr. Hooper also had rebuttal testimony, consisting of a
12 cover sheet and 15 pages of questions and answers, as
13 well as five rebuttal exhibits and schedules designated
14 as Exhibit A-36 Schedule AA-1, Exhibit A-36 Schedule AA2,
15 Exhibit A-36 Schedule AA3, Exhibit A-36 Schedule AA4, and
16 Exhibit A-36 Schedule AA5.

17 JUDGE WALLACE: Thank you. Is there any
18 objection to binding in the direct and rebuttal testimony
19 of Mr. Hooper?

20 Hearing none, the testimony is bound in.

21 Is there any objection to the exhibits
22 and associated schedules sponsored by Mr. Hooper? (No
23 response.)

24 (Testimony Bound In.)

25 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
JEROME K. HOOPER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JEROME K. HOOPER

Line
No.

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

2 A1. My name is Jerome K. Hooper (he/him/his). My business address is DTE Energy
3 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
5 Company (DTE Energy).

6

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

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

9

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

11 A3. I received a Bachelor of Science Degree in Health Care Administration from
12 California Coast University in 2013. I have also completed graduate-level
13 coursework in Management at Colorado Technical University

14

15 **Q4. What is your current position and work experience?**

16 A4. My current position is Manager, Health & Welfare Benefits and Occupational
17 Health. I joined the DTE Electric full time in 2000 and have held positions with
18 increasing responsibility within Human Resources. These were Medical Assistant,
19 Disability Management Professional, and Sr. Labor Relations Specialist.. In 2017,
20 I became Supervisor, Health & Welfare Benefits, and assumed my current position
21 in 2021. Prior to joining DTE, I was employed by the Ingham County Health
22 Department as a Health Screening Technician. I was previously employed at
23 Sparrow Health System (now known as University of Michigan Health- Sparrow)
24 in various medical laboratory and patient care roles.

Line
No.

1 **Q5. What are your current responsibilities as Manager of Health and Welfare**
2 **Benefits and Occupational Health?**

3 A5. As Manager of Health and Welfare Benefits and Occupational Health, I have
4 responsibility for benefit design, strategy, and administration of DTE Energy's
5 employee benefits. I also am responsible for DTE's drug and alcohol program,
6 occupational health, and employee assistance program (EAP).

7
8 **Q6. Have you participated in DTE Electric or DTE Gas proceedings before the**
9 **Michigan Public Service Commission (MPSC or Commission)?**

10 A6. Yes. I provided support to the compensation and benefits witness in the 2024 DTE
11 Gas General Rate Case (Case No. U-21291).

12

13 **Purpose of Testimony**

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

15 A7. My testimony will present an overview of benefit expense for DTE Electric for the
16 2022 historical test period and the 12 months ended December 31, 2025, projected
17 test period. Specifically, I will:

18 1. Provide support for the Company's, other post-employment benefits costs
19 (OPEB), active employee health care costs and the costs of other employee
20 benefits;

21 In summary, my testimony will support the reasonableness and validity of the
22 projected employee benefits expense to be incurred by DTE Electric for the
23 projected test period.

24

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

Line
No.

1 A8. Yes. I am sponsoring in whole, or in part, the following exhibits:

2	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
3	A-13	C5.11	Projected Operation and Maintenance Expenses -
4			Employee Pension and Benefits
5	A-13	C5.11.1	Willis Towers Watson Healthcare Trend Projection
6	A-13	C5.11.2	PwC 2024 Medical Cost Trend
7	A-13	C5.11.3	Constant Dollar Active Healthcare Adjustment
8	A-13	C5.12.2	Projected Operation and Maintenance Expenses -
9			Other Post-Employment Benefits (OPEB)

10

11 **Q9. Were these exhibits prepared by you or under your direction?**

12 A9. Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by
13 Witnesses Fix and Uzenski.

14

15 **OTHER POST-EMPLOYMENT BENEFITS (OPEB) COSTS**

16 **Q10. What are OPEB Costs?**

17 A10. OPEB costs relate to the provision of retiree medical, dental, prescription drug and
18 life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting
19 Standard Codification (ASC) section 715-60. Similar to ASC 715-30, as explained
20 by Witnessss Fix, OPEB costs are determined under ASC 715-60 at the beginning
21 of each fiscal year.

22

23 **Q11. What are the cost components of OPEB?**

24 A11. OPEB has the same basic cost components as pension costs, as described by
25 Witness Fix. They are:

Line
No.

1 Service Costs: Service Costs are the portion of the expected post-retirement benefit
2 obligation, on a present value basis, attributable to employee participation service
3 during the current period. Service Costs reflect actuarial assumptions of employee
4 turnover, age at retirement, and expected longevity. Service Costs also depends on
5 the estimated costs of providing these benefits after the employee's retirement and,
6 therefore, is impacted by both current medical cost levels and expected medical
7 cost inflation.

8

9 Interest Costs: Interest Costs are the costs arising from the current period interest
10 on the discounted Accumulated Post-Retirement Benefit Obligation (APBO). The
11 APBO was discounted to today's dollars based on a discount rate of 2.91% as of
12 December 31, 2021, which was also used to determine Interest Costs in 2022. The
13 discount rate used to measure the APBO as of December 31, 2022, was 5.19%,
14 which was also used to determine the Interest Costs on the APBO during the
15 projected test year. The discount rate of 5.19% was determined based on the
16 interest rate environment at the end of 2022, as determined in a similar manner to
17 the measurement of the Company's pension costs, as described by Witness Fix.

18

19 Expected Return on Assets: The Expected Return on Assets (ERoA), which is an
20 offset to OPEB costs, based on the forward-looking long-term financial market
21 expectations to avoid large swings in OPEB costs based on short-term investment
22 performance. The ERoA was 6.40% during the historical test year and is 7.20%,
23 7.30% and 7.30% in 2023, 2024 and 2025, respectively. The increase in the ERoA
24 is primarily due to an increase in the forward-looking long-term capital market
25 assumptions that reflects the impact of negative capital market performance in

Line
No.

1 2022. These assumptions are based on market conditions and funded status at the
2 end of 2022.

3

4 Amortizations: This cost component includes the amortizations related to deferred
5 Gains and Losses as well as Prior Service Costs. Accumulated gains and losses,
6 outside the 10% corridor, as described for pension costs by Witness Fix, are
7 amortized over the current estimated remaining service life of active participants.
8 Prior Service Costs are amortized over the estimated remaining service life of active
9 participants, at the time of the last plan change, to the age at which these employees
10 are fully eligible for the benefits.

11

12 **Q12. How are these OPEB costs expected to change between the historical test year**
13 **and the projected test year?**

14 A12. As reflected on Exhibit A-13, Schedule C5.12.2, the Company's OPEB costs are
15 projected to increase from negative \$36.661 million in the historical test year to
16 negative \$14.459 million during the projected test year. After adjustments for the
17 portion of OPEB costs transferred and capitalized, the net OPEB expense is
18 projected to be negative \$8.395 million, as shown on Exhibit A-13, Schedule
19 C5.12.2, line 17.

20

21 **Q13. Is the negative OPEB expense included in the Company's proposed revenue**
22 **requirement?**

23 A13. No. Witness Uzenski sponsors the Company's proposal to continue to defer to the
24 projected negative OPEB expense to the accumulated regulatory liability. Thus,
25 the projected OPEB expense is not reflected in the Company's proposed revenue

Line
No.

1 requirement and the negative OPEB expense is eliminated on line 18 of Exhibit A-
2 13, Schedule C5.12.2.

3

4 **Q14. Did the Commission address the OPEB regulatory liability in its Order in Case**
5 **No. U-21297?**

6 A14. Yes. In its Order in Case No. U-21297, the Company's most recent rate case, the
7 Commission adopted a seven-year amortization of the Company's OPEB
8 regulatory liability as of December 31, 2022, which resulted in an annual
9 amortization of \$18.300 million that reduced the Company's revenue requirement
10 (Case No. U-21297, Order, pp 223-224). This annual amortization of \$18.300
11 million is reflected on Exhibit A-13, Schedule C5.12.2, line 19, as a reduction to
12 OPEB expense and is also reflected on Exhibit A-13, Schedule C5.11, line 3.

13

14 **Q15. Has DTE Electric previously externally funded its OPEB costs?**

15 A15. Yes. DTE Electric has generally funded the OPEB costs included in the Company's
16 revenue requirement adopted by the Commission in previous orders through a
17 Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal
18 Revenue Code Section 401(h) trust.

19

20 **Q16. Will the Company externally fund its OPEB liability in the future?**

21 A16. No. Since the Commission approved the Company's proposal in Case No. U-20836
22 to continue the deferral of the projected negative OPEB expense, initially approved
23 by the Commission in Case No. U-17767, the Company's current and projected
24 revenue requirements do not include any OPEB expense and thus there is no
25 obligation for the Company to externally fund its OPEB liability.

Line
No.

1 **NEW HIRE VEBA COSTS**

2 **Q17. What is the New Hire VEBA?**

3 A17. The New Hire VEBA expense on Exhibit A-13, Schedule C5.11, line 4 reflect the
4 costs of the plans that are offered in lieu of the traditional retiree healthcare plan
5 for eligible employees, as adjusted for the portion of those costs that are capitalized.
6 Because the New Hire VEBA is generally offered in lieu of the Company's
7 traditional retiree healthcare plan, which is closed to most new participants, this
8 increase in costs is offset by avoided OPEB costs.

9
10 **Q18. What are the components of the Company's New Hire VEBA costs?**

11 A18. The Company's New Hire VEBA costs consist of contributions generally made for
12 newly hired employees after 2012. Specifically, the Company contributes \$4,000
13 on behalf of non-represented and certain Local 17 employees in their year of hire,
14 as prorated for month of hire, and \$4,000 every year thereafter. For employees
15 represented by Local 223, the Company makes a payment of \$1,650 on their first
16 service anniversary and contributes \$40 per week thereafter. In 2022 the average
17 Company contribution for Local 223 employees was \$2,177.

18
19 In addition, the Company recognizes a true-up of the estimate of the Company's
20 liability for contributions for non-represented and Local 17 employees that reflects
21 final determinations of plan eligibility and any forfeitures by employees that leave
22 the Company before the end of the 10-year vesting period. No such true up is
23 required for Local 223 employees because payments are made through the bi-
24 weekly payroll process and the Company doesn't receive any benefit from
25 employee departures.

Line
No.

1 **Q19. What adjustments are you proposing to the Company's New Hire VEBA**
2 **expense?**

3 A19. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 4, I am proposing two
4 adjustments to New Hire VEBA expense. The first, which is reflected on column
5 (c) represents a normalization of the Company's recorded 2022 New Hire VEBA
6 expense and the second, which is reflected in column (h) represents the projection
7 of this expense through the end of the projected test year.

8

9 **Q20. Why is a normalization adjustment required for the Company's recorded 2022**
10 **New Hire VEBA expense reflected on Exhibit A-13, Schedule C5.11, page 2,**
11 **line 4, column (c)?**

12 A20. In 2022, the Company recognized an unusually high true-up adjustment related to
13 the New Hire VEBA costs recognized in 2021 compared to the actual funding
14 requirement for 2021. Specifically, the 2021 true-up reflected as a reduction to the
15 Company's New Hire VEBA expense, which after reduction for the portion
16 capitalized, was \$1.336 million, whereas the average of the five prior years true-up
17 adjustments on a similar basis was only \$0.310 million. There were two primary
18 drivers of the large increase in the true-up recognized in 2022 related to 2021. First,
19 due to historically low levels of employee turnover during the COVID-19 pandemic
20 in 2020 there was a reduction in the number of new hires eligible to participate in
21 the plan in 2021. Second, as the economy transitioned out of the pandemic in 2021
22 and employee turnover increased, there was a substantial increase in the forfeitures
23 of accumulated balances by employees that left the Company before they were
24 vested in the plan. These two factors resulted in an unusually large true-up in 2022
25 that is non-recurring. Accordingly, the Company's 2022 recorded New Hire VEBA

Line
No.

1 expense should be increased by \$1.027 million, which represents the excess of the
2 2021 true-up over the average of true-ups recognized in the prior five-years.

3

4 **Q21. What is the basis for the projected increase in the New Hire VEBA expense?**

5 A21. The New Hire VEBA expense is projected to increase from the normalized 2022
6 expense of \$7.707 million to \$9.847 million in the projected test year. This increase
7 reflects the growth in the number of plan participants due to new hires.

8

9 **Q22. How was the projected New Hire VEBA expense developed?**

10 A22. The projected New Hire VEBA expense was developed based on the number of
11 active participants in the plans as of December 31, 2022, which was increased by
12 the number of expected new participants based on the most recent five-year average
13 of actual new plan participants prorated for the assumption that the new participants
14 would be added evenly throughout the year (i.e., divided by two). The average plan
15 participants for each year were costed-out based on the Company's required
16 contributions for each plan, as described above, to determine the projected gross
17 cost for each plan. The amount for the non-represented employees and employees
18 represented by Local 17 was then reduced by the five-year average of employee
19 forfeitures for those plan participants that left the Company before they were vested
20 in the plan. Total costs for the projected test year are projected to be \$15.320
21 million, which is reduced by 35.7% to recognize the portion of costs to be
22 capitalized, resulting in net New Hire VEBA expense of \$9.847 million. This
23 represents an average annual increase of 13.8%.

24

Line
No.

1 **ACTIVE HEALTHCARE EXPENSE**

2 **Q23. What are the healthcare benefit programs offered to active employees?**

3 A23. The Company offers a competitive active healthcare benefits package for the
4 attraction and retention of a skilled workforce. The components of these benefits
5 are summarized on Exhibit A-13, Schedule C5.11 (lines 8 through 10) and consists
6 of medical, dental, and vision benefits for active employees that are projected to
7 increase from \$50.126 million in the historic test year to \$56.083 million. This
8 increase includes the normalization of the historical Active Healthcare costs to
9 reflect a historical average of constant dollar costs, as developed on Exhibit A-13,
10 Schedule C5.11.3, and annual escalations for the adjusted medical plan trend of
11 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025, as more fully described below in
12 Q47 through Q54.

13

14 **Q24. What is the Normalization Adjustment to 2022 Active Healthcare costs as**
15 **reflected on Exhibit A-13, Schedule C5.11?**

16 A24. The year-to-year volatility of actual Active Healthcare costs makes the use of any
17 one historical period's cost a potentially unreliable starting point in the
18 determination of projected Active Healthcare costs. Accordingly, the adjustment
19 of negative \$1.260 million reflected on Exhibit A-13, Schedule C5.11, page 2 on
20 line 11 of column (c), represents a normalization of the Company's actual 2022
21 Active Healthcare costs that is designed to eliminate the volatility of the Company's
22 Active Healthcare costs through the quantification of the Company's historical
23 Active Healthcare costs per employee, as adjusted for national historical healthcare
24 cost trends. This results in an average of the Company's actual Active Healthcare
25 costs per employee that eliminates the impact of historical healthcare cost inflation

Line
No.

1 and, therefore, reflects the cost volatility due to changes in the usage of healthcare
2 services.

3

4 **Q25. What is the basis for your conclusion that year-to-year Active Healthcare costs**
5 **are volatile?**

6 A25. The primary reason the Company's Active Healthcare costs reflect substantial
7 volatility among years is that the Company is self-insured for about 70% of its
8 total Active Healthcare costs. Self-insurance results in the level of Active
9 Healthcare costs incurred by the Company being highly impacted by the mix and
10 severity of medical treatments administered to employees and their eligible
11 dependents in any given year. For example, in 2020 DTE Electric's medical claims
12 related to outpatient specialty drugs decreased by almost \$0.6 million, or over
13 25%, compared to 2019 while in 2021 claims for the same category increased by
14 over \$1.4 million or almost 90%. In addition, in 2021, inpatient care related to the
15 treatment of COVID-19 infections increased by over \$1.0 million and then
16 declined by almost \$1.2 million in 2022. Also in 2022, the Company reinstituted
17 its healthy living requirements for employee contributions for healthcare services
18 that were suspended during the pandemic. As a result, total employee contributions
19 increased in 2022 by \$2.3 million, which is an offset to the Company's Active
20 Healthcare costs. This single non-recurring increase in employee contributions
21 reduced the Company's Active Healthcare costs in 2022 by over 2.5%.

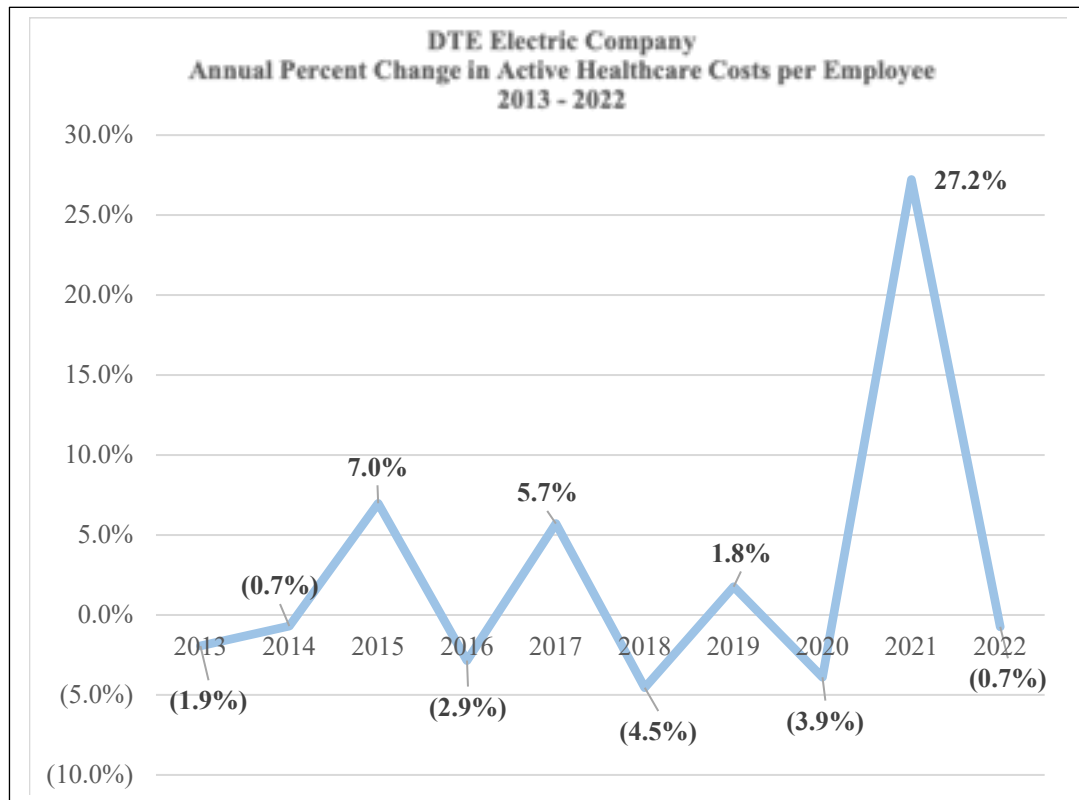
22

23 **Q26. Have you quantified the degree of volatility in the Company's Active**
24 **Healthcare Costs?**

Line
No.

1 A26. Yes. The actual annual percentage change in the Company's Active Healthcare
2 costs on a per employee basis, as adjusted for a one-time credit in 2018, is reflected
3 in Table 1 below.

4 **Table 1**



5 This chart shows that the Company's actual Active Healthcare costs have changed
6 relative to the prior year by as much as 27.2% in 2021 to a decrease of 4.5% in
7 2018, demonstrating that Active Healthcare costs can vary significantly from year-
8 to-year. While the average percent change in the Company's Active Healthcare
9 costs for the years 2013 through 2022 was 2.7%, the standard deviation of this
10 average is 9.4%.

11
12 **Q27. What is the significance of this high degree of variability in the percentage**
13 **change in the Company's actual Active Healthcare costs?**

Line
No.

1 A27. Since the Company's actual Active Healthcare costs can be impacted by variations
2 in usage, the effect of benefit plan design, and changes in pricing, any given year's
3 Active Healthcare costs will likely be an unreliable basis to establish a starting point
4 for future Active Healthcare costs. Moreover, the small sample size of the
5 experience of the Company makes it a poor predictor of future experience. In 2022,
6 the Company had about 3,400 employees enrolled in its self-insured medical plans,
7 which inclusive of dependents, represented about 9,800 total participants. The total
8 number of participants represents too small of a sample to infer that the experience
9 over a few years will reflect the long-term trends in the Company's Active
10 Healthcare costs. This small sample size is a key contributor to the year-to-year
11 variability as reflected in the high Standard Deviation relative to the average.

12

13 **Q28. Is there a method of normalizing the Company's historical Active Healthcare**
14 **costs to determine a more reliable starting point in determining Active**
15 **Healthcare costs for the projected test year?**

16 A28. Yes. The variability in the Company's actual Active Healthcare costs can be
17 normalized using constant dollar Active Healthcare costs on a per employee basis.
18 This allows for the normalization of the inherent volatility in historical Active
19 Healthcare costs through the elimination of both the impact of healthcare price level
20 changes and changes in the level of employees.

21

22 **Q29. How did you determine a constant dollar average of the Company's Active**
23 **Healthcare costs on a per employee basis?**

24 A29. Exhibit A-13, Schedule C5.11.3 reflects the Company's actual Medical, Dental, and
25 Vision components of the actual Active Healthcare costs for the years 2018 through

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1 2022, before the impact of the costs capitalized and transferred. These costs are
2 divided by the simple average of employees at the beginning and end of each year
3 to develop the Active Healthcare costs per employee. The Active Healthcare costs
4 per employee for each year is then adjusted for the actual percent increase in medical
5 trends, as reported by PwC on page 2 of Exhibit A-13, Schedule C5.11.2. Adjusting
6 the Company's actual Active Healthcare costs for the overall increases in medical
7 costs experienced by a broad universe of employers and insurance providers, as
8 reflected in the PwC study, enables the separation of the Company's year-to-year
9 variability that is driven by changes in utilization by the Company's employees and
10 their dependents from changes to overall healthcare cost trends.

11

12 The adjustment of each year's Active Healthcare costs per employee produces a
13 five-year average cost per employee on a constant dollar basis of \$12,081. By
14 multiplying this amount by the 2022 average number of employees of 6,697, a total
15 constant dollar Active Healthcare cost of \$80.911 million is generated. This
16 represents a \$2.087 million decrease relative to the Company's incurred Active
17 Healthcare costs in 2022. This amount is adjusted for the portion of Active
18 Healthcare costs charged to expense and results in a constant dollar normalization
19 adjustment of negative \$1.260 million, as reflected on Exhibit A-13, Schedule
20 C5.11.3, column (m), line 16.

21

22 **Q30. How has the Commission traditionally addressed cost elements that are**
23 **subject to volatility?**

24 A30. The Commission has routinely adopted prior year's average of the ratio of
25 uncollectibles to revenues to project the Company's future uncollectibles expense,

Line
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1 and for DTE Gas, has used an average of historical Lost and Unaccounted for Gas
2 volumes to project future Lost and Unaccounted for Gas expense. The difference
3 is that in those instances the pricing is separated from the level of activity because
4 the ratios of uncollectibles and the volumes of Lost and Unaccounted for Gas were
5 determined first, and then those ratios are priced by applying the percentage of
6 historical uncollectibles for projected revenue or the average Lost and Unaccounted
7 for Gas volumes are multiplied by the projected cost of gas rate.

8

9 In contrast, for Active Healthcare costs there is no available segregation of the
10 impact of changes in activity, as reflected in usage of health services, and the
11 pricing of those services. Because the price of healthcare services increases each
12 year, it would be unreasonable to predict future Active Healthcare costs based on
13 an average of the historical Active Healthcare costs. As a result, the only means of
14 producing a starting point for Active Healthcare costs that is normalized for
15 changes in utilization is to develop an historical average of costs that neutralizes
16 the impact of changes in price levels. This is what the constant dollar normalization
17 adjustment achieves.

18

19 **Q31. Are there any useful analogies to the Company's constant dollar Active**
20 **Healthcare adjustment?**

21 A31. Yes. From a broad perspective, the constant dollar Active Healthcare adjustment
22 should be regarded as means to neutralize the inherent volatility in the Company's
23 actual Active Healthcare costs by restating the historical costs in current dollars,
24 much as "nominal" price levels are routinely adjusted for the effects of inflation to

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1 develop inflation adjusted “real” prices. This allows for a meaningful comparison
2 of costs among years without the distortion of changes in price levels.

3

4 More specifically, DTE Electric has traditionally adjusted its actual annual
5 historical emergent replacement expenditures for inflation to develop a base
6 spending level used in developing projected costs. This approach was explicitly
7 adopted in a DTE Electric rate case where the Commission concluded “Adding
8 inflation to the historic five-year historical actual spend is appropriate for
9 calculating the starting point for normalized expenditures.” (Case No. U-20561,
10 Order issued May 8, 2020, p. 86). The continued use of a five-year inflation
11 adjusted average of Emergent Replacement Expenditures was adopted by the
12 Commission in other recent Company rate cases (Case No. U-20836, Order issued
13 November 18, 2022, p. 63, Case No. U-21297 Order issued December 1, 2023, p.
14 76).

15

16 **Q32. Has the normalization of emergent replacement expenditures for historical**
17 **inflation been contested in the Company’s recent rate cases?**

18 A32. Yes. The Attorney General has consistently opposed the normalization of historical
19 emergent replacement expenditures. In the Company’s most recent rate case the
20 Attorney General claimed that the normalization of historical expenditures for
21 inflation compounds inflationary increases and amounts to inflating forecasted
22 capital expenditures by increasing the base used in the projections (Case No. U-
23 21297, Order, p. 74). Based on this claim, the Attorney General proposed the
24 elimination of the historical inflation normalization of emergent replacement
25 expenditures. However, the Commission properly rejected the Attorney General’s

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1 proposal and adopted the Company's historical inflation normalization of emergent
2 replacement expenditures.

3

4 **Q33. Did the Commission also address the issue of the constant dollar normalization**
5 **of Active Healthcare costs in its Order in Case No. U-21297?**

6 A33. Yes. In that case the Attorney General opposed the Company's constant dollar
7 Active Healthcare cost adjustment. Like the Attorney General's arguments in
8 opposition to the historical inflation normalization of emergent replacement
9 expenditures, the Attorney General claimed the adjustment for historical healthcare
10 increases compounded inflationary increases (Case No. U-21297, Order, p. 229).
11 The Commission declined to adopt the constant dollar normalization in this matter,
12 stating that the Company did not sufficiently demonstrate that the "proposed
13 constant dollar normalization will not result in compounded inflationary pressures"
14 (Case No. U-21297 Order, p. 232).

15

16 **Q34. Does the constant dollar adjustment result in compound inflationary**
17 **pressures?**

18 A34. No. Just like the normalization of historical emergent replacement expenditures,
19 the constant dollar Active Healthcare costs adjustment merely recasts the
20 Company's historical Active Healthcare costs for the impact of historical medical
21 cost escalations. This adjustment enables the development of a five-year average
22 Active Healthcare costs per employee on basis that excludes the impact of changes
23 in prices. The only difference between the two normalization adjustments is that
24 emergent replacement expenditures are adjusted for overall inflation as measured
25 by the Consumer Price Index whereas the Active Healthcare normalization

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1 adjustment is based on actual historical national medical cost trends as measured
2 by the PwC actual medical cost increases. This difference in historical bases for
3 escalation recognizes that overall inflation is an inappropriate measure of historical
4 medical cost escalations. The escalation of the Company's historical Active
5 Healthcare costs per employee for actual national medical cost increases allows the
6 establishment of a normalized Active Healthcare costs per employee for the years
7 2018 through 2022, which is used to create a five-year average as a starting point
8 to be used to project the Company's future Active Healthcare costs. Accordingly,
9 it is inaccurate to conclude that the normalization of the Company's Active
10 Healthcare costs per employee results in the compounding of inflationary pressures.

11

12 **Q35. How is this constant dollar normalization adjustment reflected on Exhibit A-**
13 **13, Schedule C5.11?**

14 A35. The total constant dollar normalization adjustment of negative \$1.260 million is
15 allocated to the Active Healthcare cost components of Medical Expense, Dental
16 Expense, and Vision Expense based on the proportion of the expenses for each of
17 these categories in 2022 on Exhibit A-13, Schedule C5.11, page 2 of 2, column (c),
18 lines 8 through 10, to determine the Adjusted Historical Test Period expenses in
19 column (d), which is then adjusted for the projected active healthcare trend factors
20 through the end of the projected test period.

21

22 **Q36. What is the basis for your future trend factor in active healthcare costs used**
23 **for the projected periods in this proceeding?**

24 A36. The annual unadjusted medical plan trend factors of 7.10% for 2023, 7.50% for
25 2024, and 7.00% for 2025, are based on projections for healthcare trends provided

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1 by the healthcare experts at Willis Towers Watson (WTW), as reflected in Exhibit
2 A-13, Schedule C5.11.1. These unadjusted trend factors are reduced by 2.00% in
3 2023, 2.50% in 2024, and 3.00% in 2025 to reflect the expected savings to be
4 realized by the Company's Wellness program. Accordingly, the active healthcare
5 expense projections are based on the Company's 2022 normalized expense as
6 escalated by the adjusted trend factors of 5.10% in 2023, 5.00% in 2024, and
7 4.00% in 2025.

8

9 **Q37. How were these trend factors determined?**

10 A37. WTW's first step is to develop the Allowed Trend, which is based on its internal
11 guidance and represents its consensus expectation for medical and prescription drug
12 costs. WTW developed the Allowed Trend based on its internal book of business
13 and national survey as well as data from United States government offices and
14 agencies, and various third-party sources, as described on page four of Exhibit A-
15 13, Schedule C5.11.1. The Allowed Trend is adjusted for the Company's average
16 fixed plan design leveraging to develop the future Medical Plan Trend, which is the
17 basis of the Company's projected active healthcare costs.

18

19 **Q38. What assumptions are reflected in WTW's overall trend factors?**

20 A38. WTW's key assumptions for 2023 are described on page five of Exhibit A-13,
21 Schedule C5.11.1. Specifically, WTW assumes that overall inflation will be
22 between 2.50% and 4.00%. Added to the overall inflation is the incremental
23 healthcare inflation of between 1.00% and 2.15%, which is premised on the
24 assumption that healthcare inflation will likely revert to the historical pattern of
25 healthcare inflation exceeding overall inflation. This assumption reflects the

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1 expectation that labor shortages in the healthcare industry will become more acute
2 as well as the likelihood of increased pricing for long-term contracts between
3 insurance carriers and healthcare providers. Finally, WTW expects the impact of
4 higher utilization will add between 1.75% and 3.25% to the expected trend factors,
5 which recognizes traditional experience in the low end assumption and the high
6 end assumption reflects the risk that COVID-19 related disruptions in the delivery
7 of healthcare services will lead to future increases in utilization. In sum, WTW
8 expects the overall medical trend in 2023 will increase between 5.25% and 9.40%.

9

10 **Q39. How was the 2023 trend of 7.10% developed by WTW for the escalations used**
11 **by Company in its projections?**

12 A39. As also reflected on page five of Exhibit A-13, Schedule C5.11.1, in the column
13 labeled DTE Energy, the assumptions used in the development of the 6.60%
14 unleveraged medical trend are detailed. Specifically, WTW assumes general
15 inflation of 3.20%, which is based on the actual increase in the CPI through July
16 2023. Added to the general inflation assumption is 1.50% for the assumed
17 incremental medical cost related inflation, which is slightly less than the midpoint
18 of the range of 1.00% to 2.15% identified for the overall medical trend. Finally,
19 1.90% is added to reflect the expected change in the Company's utilization and
20 service mix. This 1.90% addition for the impact of expected increase related to
21 utilization and service mix at the Company is based on relative risk scores
22 developed by Merative, a firm specializing in healthcare analytics, that projects that
23 the Company's relative risk will increase by 5.30% over the next three years or
24 about 1.70% annually. An additional 0.2% is added to the 1.70% to reflect the
25 expected impact of the Company's increased utilization of higher cost specialty

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1 prescription drugs, resulting in a total increase due to utilization and service mix of
2 1.90%. A description of Merative and the support for the relative risk scores is
3 reflected on page six of Exhibit A-13, Schedule C5.11.1.

4

5 Based on these assumptions WTW's 2023 medical trend is 6.60% before the impact
6 of the Company's fixed plan design leveraging or 7.10% inclusive of the
7 Company's fixed plan design leveraging.

8

9 **Q40. Can you describe fixed plan design leveraging?**

10 A40. Yes. Fixed plan design leveraging is the impact on the Company's costs of fixed
11 cost-sharing plan design items, such as deductibles, coinsurance, copays and out of
12 pocket maximum.

13

14 **Q41. Are you aware of any corroborating sources that support the reasonableness**
15 **of WTW's projections?**

16 A41. Yes. A study released in 2023 by PwC's Health Research Institute, as reflected in
17 Exhibit A-13, Schedule C5.11.2, projects that medical costs will increase by 6.0%
18 in 2023 and 7.0% in 2024.

19 These studies support the reasonableness of the healthcare trend projections
20 provided by WTW.

21

22 **Q42. Have the projections of future medical trends relied upon by the Company in**
23 **recent years been accurate?**

24 A42. Yes. In recent years the Company's average projected medical trend rates were
25 5.5%, 6.1%, 5.9% and 6.7% for the years 2019, 2020, 2021 and 2022, respectively,

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1 or a four-year average of 6.1%. The actual increase in national medical costs
2 compiled by PwC, as reflected on Exhibit A-13, Schedule C5.11.2, page 2, were
3 5.7%, 6.0%, 7.0% and 5.5% for the years 2019, 2020, 2021 and 2022, respectively,
4 or a four-year average of 6.1%. In summary, the Company's projected trend rates,
5 which were developed consistent with the method used by WTW in the trend rates
6 reflected on Exhibit A-13, Schedule C5.11.1, have matched the actual national
7 medical trend rates. This demonstrates that the Company's projected trend rates
8 have been accurate predictors of actual medical trend rates.

9

10 **Q43. Is the Company's recent experience a reliable basis for predicting future**
11 **increases?**

12 A43. No. The high variability of the annual percent change in the Company's actual
13 Active Healthcare costs per employee, as reflected in Table 1 discussed in response
14 to Q37, highlights the inherent flaw in using historical annual changes in the
15 Company's Active Healthcare costs as basis for projecting future increases. As I
16 previously discussed, the average annual percentage increase in the Company's
17 actual Active Healthcare costs for the year 2013 through 2022 was 2.7%, the
18 Standard Deviation of that average is 9.4%. This means that for about 68% of the
19 years, the Company's annual change in Active Healthcare costs could range from
20 negative 6.7% to a positive 9.1%. This extreme level of volatility renders historical
21 changes in Active Healthcare costs to be virtually worthless in determining future
22 Active Healthcare costs.

23 Given the unreliability of the Company's actual annual change in Active Healthcare
24 costs, it is prudent to project future increases in Active Healthcare costs based on

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1 the adjusted WTW medical trend rates, which have a proven record of accuracy,
2 rather than the Company's historical experience.

3

4 **OTHER EMPLOYEE BENEFITS COSTS**

5 **Q44. What are Other Benefits Costs?**

6 A44. The costs of the Company's Other Employee Benefits are also reflected on Exhibit
7 A-13, Schedule C5.11 (lines 13 through 25). These costs include a variety of other
8 benefits including Accrued Vacation, Wellness Program, Life Insurance, Long-
9 Term Disability, associated with the Affordable Care Act (ACA), General Benefits,
10 and Benefit Plan Administration Fees. The remaining Other Benefits Costs are
11 described by Witness Fix. In total, these expenses are projected to increase from
12 \$5.318 million in the historic test year to \$18.554 million in the projected test year,
13 as shown on line 26 of Exhibit A-13, Schedule C5.11. As described in detail below,
14 as well as by Witness Fix, and as reflected on page 2 of Exhibit A-13, Schedule
15 C5.11, column (c), \$11.170 million of this increase relates adjustments to normalize
16 the Other Benefits expense reported in 2022 and \$2.067 million relates to projected
17 increases, as reflected on column (i).

18

19 **Q45. What adjustments are you proposing to Accrued Vacation expense?**

20 A45. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 13, I am proposing
21 two adjustments to Accrued Vacation expense. The first, which is reflected on
22 column (c), represents a normalization of the Company's recorded 2022 accrued
23 Vacation expense and the second, which is reflected in column (i), represents the
24 projection of this expense through the end of the projected test year.

25

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1 **Q46. What is the Normalization of the Company's Accrued Vacation expense?**

2 A46. Accrued Vacation expense can vary from year to year based on the timing of the
3 vacation earned and usage of vacation time by employees, as well as forfeitures.
4 This volatility in annual accrued vacation expense has been traditionally addressed
5 using a five-year average of the annual expense. Accordingly, the adjustment to
6 Vacation Accrual expense reflected on page 2 of Exhibit A-13, Schedule C5.11,
7 line 13, column (c), is based on the average of the recorded expense for the years
8 2018 through 2022 of negative \$0.497 million. This results in an increase to
9 Accrued Vacation expense of \$4.942 million.

10

11 **Q47. What is the basis for your projection of the Company's Accrued Vacation**
12 **expense?**

13 A47. The adjusted five-year average is escalated by the projected 3.0% labor annual
14 cost increases through the end of the projected test year.

15

16 **Q48. How did you project the increase in the Company's Wellness Program**
17 **expense?**

18 A48. As referenced in my discussion of Active Healthcare expense, the Company has a
19 Wellness Program designed to produce significant reductions in future active
20 healthcare expense. Wellness Program expense is projected to increase from
21 \$4.995 million in the historical test year to \$5.560 million in the projected test year
22 based on the adjusted healthcare trend annual escalations of 5.10% in 2023, 5.00%
23 in 2024, and 4.00% in 2025 (Exhibit A-13, Schedule C5.11, line 17).

24

25 **Q49. How did you project the Company's Life Insurance Expense?**

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1 A49. The Company's Life Insurance expense relates to life insurance provided to
2 employees that provides coverage that is generally equal to the employees base
3 annual salary. Because the coverage is based on employee salaries, I have adjusted
4 the 2022 expense of \$252,000 by the annual wage escalation of 3.0%, which
5 produces a Life Insurance expense in the projected test year of \$276,000, as
6 reflected on line 18 of Exhibit A-13, Schedule C5.11.

7

8 **Q50. How have you projected the Company's Long-Term Disability Expense?**

9 A50. Actual 2022 Long-Term Disability Expense is projected to increase from \$1.354
10 million to \$1.480 million during the projected test year based on the assumption
11 that disability claims costs are primarily driven by labor costs escalations, which
12 are assumed to be 3.0% per year between 2022 and the end of the projected test
13 year, as reflected on line 19.

14

15 **Q51. How did you develop the projections for the other items included in Other**
16 **Benefits on Exhibit A-13, Schedule C5.11?**

17 A51. On lines 20 through 25 of Exhibit A-13, Schedule C5.11 are the components of the
18 other items included in the Company's Other Benefits. The 2022 ACA expense of
19 \$19,000 on line 20 reflects the actual expense recognized for the Comparative
20 Effectiveness Research Fee, which is escalated at the annual Active Healthcare
21 inflation rates, resulting in \$22,000 of ACA expense for the projected test year.
22 General Benefits Expense is reflected on line 21 and is projected based on the actual
23 amounts recorded in 2022 of \$2.198 million and escalated at the overall rate of
24 inflation as measured by the Consumer Price Index through the end of the projected
25 test year, which results in projected General Benefits Expense of \$2.395 million.

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1 Benefit Plan Administration Fees (line 22) are projected to increase to \$7.296
2 million based on the projected overall inflation rate assumptions. Also included in
3 Other Benefits, Exhibit A-13 Schedule C5.11 are Medical Refund Amortization
4 (line 24) and O&M Project reimbursements (line 25), which are both sponsored by
5 Witness Uzenski.

6

7 **Q52. What are the Company's total projected employee pensions and benefits**
8 **expenses for the projected test year?**

9 A52. The total projected employee pensions and benefits expenses of \$103.590 million
10 is reflected on Exhibit A-13, Schedule C5.11, line 27. After adjustments for the
11 impact of the portion of these costs to be capitalized and transferred, as well as the
12 elimination of costs allocated to the Company's separate surcharge programs, as
13 sponsored by Witness Uzenski, employee pensions and benefits expenses for the
14 projected test year are reduced to \$84.259 million, as reflected on Exhibit A-13,
15 Schedule C5.11, line 31.

16

17 **Q53. Does this complete your direct testimony?**

18 A53. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

JEROME K. HOOPER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JEROME K. HOOPER

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

3 A1. My name is Jerome K. Hooper (he/him/his). My business address is DTE Energy
 4 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
 5 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
 6 Company (DTE Energy).

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. My testimony will rebut the testimony of Staff Witness Rueckert and Attorney
 15 General (AG) witness Coppola. Specifically, I will rebut:

- 16 • Staff Witness Rueckert's and AG Witness Coppola's proposed adjustments
- 17 to the Company's projected Active Healthcare expense,
- 18 • Staff Witness Rueckert's proposed adjustment to General Benefits expense,
- 19 and,
- 20 • Staff Witness Rueckert's proposed adjustment to Benefit Administration
- 21 Fees.

22 The absence of a discussion of other matters in my testimony should not be
 23 regarded as an indication that I agree with all other aspects of the Staff's and
 24 intervenor's testimony. The narrow focus of my testimony is instead a consequence
 25 of a focus on priority issues in recognition of the available resources.

Line
No.

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

2 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

Exhibit	Schedule	Description
A-36	AA1	Active Healthcare Expense: Updated Staff
A-36	AA2	Active Healthcare Costs: 2017-2023
A-36	AA3	General Benefits Expense: Updated Staff
A-36	AA4	Benefit Administration Fees: Updated Staff
A-36	AA5	Benefits Adjustments: Summary

9

10 **Q5. Were these exhibits prepared by you or under your direction?**

11 A5. Yes, they were.

12

13 **Active Healthcare Expense**

14 **Q6. What adjustment did Staff Witness Rueckert propose to the Company's**
15 **Active Healthcare Expense?**

16 A6. Staff Witness Rueckert develops the Company's projected Active Healthcare
17 expense based on the Company's actual 2023 Active Healthcare costs of \$80.975
18 million, escalated by the five-year average increase in the Company's Active
19 Healthcare costs for the years 2018 through 2023 of 4.83%, which results in Active
20 Healthcare costs for the projected test year of \$88.989 million. Staff Witness
21 Rueckert adjusts this cost for the portion of Active Healthcare costs expensed in
22 2022 of 60.4% to develop Active Healthcare expense for the projected test year of
23 \$53.749 million (Rueckert Revised Direct, page 8, lines 13-19).

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1 **Q7. Do you agree with Staff Witness Rueckert's adjustment for Active Healthcare**
2 **expense?**

3 A7. No. Staff Witness Rueckert's approach, based on 2023 Active Healthcare costs as
4 escalated by 4.83% annually, is flawed because it relies on a single year of the
5 Company's Active Healthcare costs as a starting point, rather than my proposed
6 Constant Dollar normalized starting point, and uses an historical average of the
7 Company's actual percent changes in the Company's Active Healthcare costs,
8 rather than my use of projected medical trend rates. However, I will not repeat my
9 arguments in support of both the Constant Dollar normalization and projected
10 medical trend rates from my Direct testimony (Hooper Direct, page 14, line 13
11 through page 18, line 10). Instead, my rebuttal will offer a correction to Staff
12 Witness Rueckert's projection.

13

14 **Q8. What is your proposed correction to Staff Witness Rueckert's projected Active**
15 **Healthcare expense?**

16 A8. In 2023, the Company received a one-time credit from its Pharmacy Benefit
17 Manager (PBM) that reduced its Active Healthcare costs by \$1.134 million. Staff
18 Witness Rueckert's use of the Company's Active Healthcare costs in 2023 includes
19 that one-time credit. Because this is clearly a non-recurring item, it should be
20 excluded from the 2023 Active Healthcare costs used in determining both the
21 starting point and the historical average annual escalation rate.

22

23 **Q9. Have you computed the impact of the one-time credit on Staff Witness**
24 **Rueckert's historical analysis of the Company's Active Healthcare costs?**

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1 A9. Yes. Exhibit A-36, Schedule AA1 reflects a recalculation of the Staff Witness
2 Rueckert's Active Healthcare cost analysis included on Exhibit S-14-4 that includes
3 an adjustment for the one-time credit. Specifically, the credit of \$1.134 million is
4 reflected in Exhibit A-36, Schedule AA1 on line 25, column (g). Exclusion of the
5 credit increases the Company's Active Healthcare costs in 2023 to \$82.109 million,
6 or a cost per employee of \$12,541, which increases the five-year average annual
7 change in Active Healthcare costs to 5.11% compared to Staff Witness Rueckert's
8 five-year average of 4.83%.

9

10 **Q10. Have you developed an update of Staff Witness Rueckert's Active Healthcare**
11 **expense projection that reflects the adjustment for the one-time credit?**

12 A10. Yes. Exhibit A-36, Schedule AA5, which is a summary of the Company's rebuttal
13 adjustments to its Benefits expense, reflects the adjusted 2023 Active Healthcare
14 expense of \$49.589 million in line 1, column (c) and applies the updated annual
15 escalation rate of 5.11% for 2024 and 2025 to develop an updated 2025 Active
16 Healthcare expense of \$54.784 million. This represents an increase to Staff
17 Witness Rueckert's projection of \$865,000.

18

19 **Q11. What did AG Witness Coppola propose regarding the Company's projected**
20 **Active Healthcare expense?**

21 A11. AG Witness Coppola projected Active Healthcare expense based on the Company's
22 actual 2023 Active Healthcare expense of \$43.241 million, as adjusted for the impact
23 of the 2022 proportion capitalized (an increase of \$5.663 million) and the one-time
24 PBM credit (an increase of \$685,000), which resulted in an adjusted 2023 Active
25 Healthcare expense of \$49.589 million. This amount was escalated by the

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1 compound average annual increase in the Company's Active Healthcare costs for
2 the years 2018 through 2022 computed by AG Witness Coppola of 3.33%. This
3 results in Active Healthcare costs for the projected test year of \$52.947 million
4 (Exhibit AG-43).
5

6 **Q12. Do you agree with AG Witness Coppola's projection of the Company's Active**
7 **Healthcare expense?**

8 A12. No. First, AG Witness Coppola rejects the Company's proposed Constant Dollar
9 normalization adjustment based on the claim that the Constant Dollar adjustment it
10 is "simply a process that increases historical costs in a way that is divorced from
11 reality" (Coppola Direct, page 112, lines 10-14). This description of the Constant
12 Dollar normalization highlights AG Witness Coppola's misunderstanding of the
13 principles underlying the Constant Dollar normalization. However, my Direct
14 testimony fully explains the basis of the Constant Dollar normalization adjustment
15 and therefore that explanation won't be repeated here (Hooper Direct, page 13, line
16 13 through page 18, line 20). Second, AG Witness Coppola's proposes to use the
17 historical increase in the Company's Active Healthcare costs from 2018 through
18 2022, yet incongruously uses the 2023 adjusted Active Healthcare expense for the
19 basis of determining the Active Healthcare expense for the projected test year.
20 While the use of historical increases in the Company's Active Healthcare costs
21 continues to be a poor predictor of the Company's future Active Healthcare costs
22 rather than projected medical trends, as described in my Direct testimony (Hooper,
23 page 22, line 43 through page 44, line 2), I won't repeat the arguments here.
24

25 **Q13. Is AG Witness Coppola's use of the annual increase in the Company's Active**
26 **Healthcare costs for the year 2018 through 2022 reasonable?**

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1 A13. No. While I dispute the appropriateness of using the Company's historical annual
2 percent changes in its Active Healthcare costs as a basis for determining projected
3 Active Healthcare costs, there is no justification for using an historical period in
4 developing the average percent change that excludes the most recent data.
5

6 **Q14. Does AG Witness Coppola's use of the 2018 through 2022 annual percent**
7 **change in the Company's Active Healthcare costs have a material impact on**
8 **the five-year average?**

9 A14. Yes. Exhibit A-36, Schedule AA2 reflects the Company's Active Healthcare costs
10 per employee for each of the years 2017 through 2023, with the 2023 amounts
11 adjusted for the one-time PBM credit discussed above. This schedule shows that
12 the five-year average change in the Company's Active Healthcare costs is 5.11%
13 for the years 2019 through 2023 but is only 3.96% for the years 2018 through 2022,
14 or a difference of 29.0%. While AG Witness Coppola describes the 3.33%
15 historical percentage change he has developed as the "annual rate of increase"
16 (Coppola Direct, page 113, lines 7-8), it is strikingly close to the compound annual
17 growth rate of 3.35% in Active Healthcare costs between the years 2017 and 2022.
18 In contrast, the compound annual growth rate between the years 2018 and 2023 is
19 4.56%, or a difference of 36.3%. The arbitrary inclusion of the Company's Active
20 Healthcare costs for 2017 and the exclusion of 2023, as proposed by AG Witness
21 Coppola, results in a dramatic understatement of both the average of the annual
22 increase for the five years and the compound annual growth rate. There is simply
23 no logical basis for the use of the outdated historical annual average growth rate for
24 the years 2018 through 2022 when more recent data are available.

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1 **Q15. Do you propose any corrections to AG Witness Coppola's projection of Active**
2 **Healthcare expense?**

3 A15. Yes. Because AG Witness Coppola appropriately included the change in the
4 proportion of costs capitalized in 2023 and impact of the one-time credit in 2023,
5 Witness Coppola proposes a 2023 starting point that matches the corrected Staff
6 Active Healthcare expense, as reflected on Exhibit A-36, Schedule AA5 of \$49.589
7 million. Therefore, the only correction that needs to be made to AG Witness Coppola's
8 projection is to reflect the updated five-year average of annual changes in Active
9 Healthcare costs of 5.11%, as developed on Exhibit A-36, Schedule AA5. This
10 results in Active Healthcare expense for the projected test year of \$54.784 million,
11 which represents an increase of \$1.837 million to AG Witness Coppola's proposal.

12

13 **Q16. What adjustment did Staff Witness Rueckert propose to the Company's**
14 **General Benefits expense?**

15 A16. Staff Witness Rueckert proposes a reduction to the Company's General Benefit
16 expense based on actual 2023 General Benefit expense escalated by a five-year
17 average of the annual percent change in General Benefit expense of negative
18 10.24%. Staff Witness Rueckert's approach results in projected General Benefits
19 expense for 2025 of \$1.051 million (Rueckert Revised Direct, page 9, lines 14
20 through 17).

21

22 **Q17. Do you agree with Staff Witness Rueckert's projection of General Benefits**
23 **expense?**

24 A17. No. Staff Witness Rueckert's projection of General Benefits expense has four
25 flaws. First, because it is based on the Company's actual General Benefits expense

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1 in 2023, it ignores two one-time items that reduced the Company's expense in 2023.
2 Second, by using the 2023 actual General Benefits expense in 2023, unadjusted for
3 the two one-time expense reductions, the five-year average of the annual change in
4 General Benefits expense is understated. Third, Staff Witness Rueckert computes
5 the average annual percent change in General Benefits of negative 10.24% based
6 on the annual percent change in the Company's General Benefits expense rather
7 than the General Benefits costs. Last, because Staff Witness Rueckert uses the
8 Company's 2023 actual proportion of General Benefits costs capitalized, which
9 was distorted by the impact of O&M reductions implemented in 2023, the projected
10 General Benefits expense is understated.

11

12 **Q18. What were the two one-time cost reductions in General Benefits in 2023?**

13 A18. As a result of the financial challenges that confronted the Company in 2023 the
14 Company implemented a number of temporary cost reduction initiatives. Specific
15 to General Benefits, the Company suspended its tuition reimbursement program for
16 employees pursuing higher education and eliminated its employee service
17 anniversary award program. This resulted in a reduction in General Benefits costs
18 of \$629,000 related to tuition reimbursement and \$651,000 related to employee
19 service anniversary awards. Both of these two cost reductions in 2023 are
20 temporary and should be excluded from both the starting point in determining
21 projected General Benefits expense and in the determination of the five-year
22 historical average of annual percent changes used to escalate General Benefits
23 expense through the end of the projected test year.

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1 **Q19. Why is it improper to use the five-year average of the percent change in**
2 **General Benefits expense rather than the five-year average of the General**
3 **Benefits costs?**

4 A19. The use of the five-year average of the annual percent change in the Company's
5 General Benefits expense is improper as a basis for determining future escalations
6 because the historical average is distorted by changes in the proportion of General
7 Benefits costs capitalized. For example, in 2018 the proportion General Benefits
8 costs allocated to expense was 68.0%, whereas in 2023 the proportion of General
9 Benefits costs allocated to expense declined to 58.7%. This decline in the
10 proportion of General Benefits costs allocated to expense distorts the average
11 annual change in General Benefits expense because it reflects both the change in
12 costs and the change in the proportion of General Benefits costs charged to expense.
13 A more meaningful measure of the average annual percent change is based on the
14 change in General Benefits costs, undistorted by changes in proportion of costs
15 capitalized.

16

17 **Q20. What proportion of General Benefits costs allocated to expense should be used**
18 **in determining the normalized 2023 General Benefits expense?**

19 A20. The actual 2023 proportion of General Benefits costs allocated to expense was
20 58.7%. However, the proportion of General Benefits costs allocated to expense in
21 2022 was 64.6%. Because the 2023 proportion of General Benefits costs charged
22 to expense was distorted by the temporary O&M reductions implemented by the
23 Company, as described by Company Witness Uzenski, the proportion of General
24 Benefits costs allocated to expense in 2022 is more representative of the proportion
25 that will be allocated to expense in the projected test year. Accordingly, the 2023

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1 General Benefits expense should be adjusted for the change in the proportion
2 allocated to expense.

3

4 **Q21. Have you computed the impact of the one-time reductions in General Benefits**
5 **costs in 2023, the annual percent change in General Benefits costs and the**
6 **change in the proportion General Benefits costs allocated to expense in 2023?**

7 A21. Yes. Exhibit A-36, Schedule AA3 reflects a restatement of Staff Witness
8 Rueckert's Exhibit S-14-4 that includes the impact of the two one-time adjustments
9 and the use of the proportion of General Benefits costs allocated to expense in 2022.
10 The impact of these adjustments is to increase the total General Benefits costs in
11 2023 by \$1.280 million, which increases the five-year average of the historical
12 average annual change in General Benefits costs to negative 0.51% compared to
13 Staff Witness Rueckert's five-year average of the change in General Benefits
14 expense of negative 10.24%. The adjustment for the two one-time cost reductions
15 increases the Company's 2023 General Benefits expense by \$826,000, which
16 results in an adjusted 2023 General Benefits expense of \$2.262 million.

17

18 **Q22. How do these adjustments to the Company's 2023 General Benefits expense**
19 **and the five-year average of the annual percent change in General Benefits**
20 **costs impact the Staff Witness Rueckert's projected General Benefits expense?**

21 A22. The impact of these corrections to Staff Witness Rueckert's projected General
22 Benefits expense is reflected on Exhibit A-36, Schedule AA5, which starts with the
23 adjusted General Benefits expense of \$2.262 million and escalates this amount by
24 the five-year average of the annual change in the Company's General Benefits costs
25 of a negative 0.51% for both 2024 and 2025 to develop an updated General Benefits

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1 expense for the projected test year of \$2.239 million. This projection is \$1.188
2 million higher than the General Benefits expense projected by Staff Witness
3 Rueckert.

4

5 **Q23. What adjustment did Staff Witness Rueckert propose to the Company Benefit**
6 **Administration Fees?**

7 A23. Staff Witness Rueckert proposes a reduction in the Company's projected Benefit
8 Administration Fees based on the 2023 actual Benefits Administration Fees
9 expense in 2023 escalated by a five-year average of annual percent change in the
10 Benefit Administration fees for the years 2019 through 2023. Staff Witness
11 Rueckert's projects Benefit Administration Fees of \$4.708 million, which
12 represents a reduction in the Company's projected Benefit Administration Fees of
13 \$2.855 million (Rueckert Revised Direct, page 10, lines 19 through 22).

14

15 **Q24. Do you agree with Staff Witness Rueckert's proposal?**

16 A24. No. Staff Witness Rueckert's projection of Benefit Administration Fees has two
17 flaws. First, Staff Witness Rueckert's five-year average of the annual change in
18 Benefit Administration Fees is based on the Company's Benefits Administration
19 Fees expense, after reduction for the proportion of the costs capitalized, which like
20 General Benefits, is distorted by changes in the proportion of Benefit
21 Administration Fees capitalized. Second, Staff Witness Rueckert's projected
22 Benefit Administration Fees is based on the proportion of Benefit Administration
23 Fees allocated to expense in 2023, which was distorted by one-time O&M
24 reductions implemented by the Company in 2023, as explained by Company
25 Witness Uzenski.

Line
No.

1 **Q25. Have you computed a revised Benefit Administration Fees expense for the**
2 **projected test year that reflects the impact of using a five-year average of**
3 **annual percent change in the Company's Benefit Administration Fees costs**
4 **and the change in the proportion Benefit Administration Fees costs allocated**
5 **to expense in 2023?**

6 A25. Yes. Exhibit A-36, Schedule AA4 reflects a restatement of Benefit Administration
7 Fees on Staff Witness Rueckert's Exhibit S-14-4, which develops a five-year
8 average of the annual percent change in the Benefit Administration Fees costs,
9 unadjusted for the proportion of costs capitalized, of negative 3.66%, compared to
10 Staff Witness Rueckert's five-year average of the changes in the Benefit
11 Administration Fees of negative 5.57%. This schedule also adjusts the Benefit
12 Administration Fees expense in 2023 of 54.8% to the 2022 proportion Benefit
13 Administration Fees allocated to expense of 60.1%.

14

15 **Q26. How do these updates of Benefit Administration Fees impact Staff Witness**
16 **Rueckert's projections of Benefits Administration Fees?**

17 A26. Exhibit A-36, Schedule AA5 reflects the derivation of an updated projection
18 Benefit Administration Fees based on the adjusted 2023 Benefit Administration
19 Fees expense adjusted to reflect the 2022 proportion of Benefit Administration Fees
20 capitalized of \$5.788 million and escalated in 2024 and 2025 by the five-year
21 average of the annual change in Benefit Administration Fees costs of negative
22 3.66%. The combination of the adjusted 2023 Benefit Administration Fees expense
23 and corrected annual escalations results in projected Benefit Administration Fees
24 for 2025 of \$5.372 million, which is an increase of \$664,000 to Staff Witness
25 Rueckert's projection.

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1 **Q27. Is the use of the historical change in the costs rather than expense and the use**
2 **of the 2022 proportion of costs allocated to expense for General Benefits and**
3 **Benefits Administration Fees consistent with Staff Witness Rueckert's**
4 **proposed Active Healthcare expense?**

5 A27. No. Staff Witness Rueckert properly based the five-year average of the annual
6 percent change used in escalating 2023 Active Healthcare expense based on the
7 annual percent change in Active Healthcare costs rather than the annual percent
8 change in Active Healthcare expense. Similarly, Staff Witness Rueckert properly
9 used the 2022 proportion of Active Healthcare costs allocated to expense in the
10 development of the projected Active Healthcare expense. Accordingly, the
11 adjustments I'm proposing for General Benefits expense and Benefit
12 Administration Fees expense are consistent with Staff Witness Rueckert's
13 development of projected Active Healthcare expense.

14

15 **Q28. Does this conclude your rebuttal testimony?**

16 A28. Yes, it does.

1 JUDGE WALLACE: All right. Please go
2 ahead.

3 MS. REITZEL: Thank you, your Honor. DTE
4 would now move to bind into the record the Direct
5 Testimony of Rachel C. Steudle, which consists of a cover
6 sheet and 38 pages of questions and answers, as well as
7 four direct exhibits and schedules, designated as Exhibit
8 A-12 Schedule B5.4, of which she is a cosponsor; Exhibit
9 A-13 Schedule C5.6.1, Exhibit A-22 Schedule L1, and
10 Exhibit A-31 Schedule V1. Ms. Steudle also had rebuttal
11 testimony, consisting of a cover sheet and 27 pages of
12 questions and answers, as well as five rebuttal exhibits
13 and schedules, designated as Exhibit A-42 Schedule GG1,
14 Exhibit A-42 Schedule GG2, Exhibit A-42 Schedule GG3,
15 Exhibit A-42 Schedule GG4, and Exhibit A-42 Schedule GG5.

16 JUDGE WALLACE: Thank you. Is there any
17 objection to binding in the direct and rebuttal testimony
18 of Ms. Steudle?

19 Hearing none, the testimony is bound in.

20 Is there any objection to the exhibits
21 and associated schedules sponsored by Ms. Steudle? (No
22 response.)

23 (Testimony bound in.)

24 - - -

25

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
RACHEL C. STEUDLE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF RACHEL C. STEUDLE

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No.

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

2 A1. My name is Rachel Steudle, Director of Tree Trimming, One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Electric Company, known simply as
4 DTEE.

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 graduated from Skidmore College with a Bachelor of Art in Economics and
11 Environmental Studies in 2012. I completed a Master of Art in Applied Economics,
12 and a Master of Science in Energy Systems from the University of Michigan in
13 2015.

14

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

16 A4. I began my career with DTEE in 2015 and have been employed there since. I joined
17 DTEE in the Corporate Strategy team and spent four years supporting a broad range
18 of strategic projects, primarily focused on the DTE Electric company. I concluded
19 my time with Corporate Strategy as an Associate, responsible for leading and
20 managing projects with minimal oversight. In 2019, I was promoted to Manager,
21 Tree Trimming where I was responsible for leading the tree trim scheduling
22 process, managing the program's budget, and supporting strategic efforts. In mid-
23 2020, I was promoted to the Strategy Manager role for Tree Trimming. In this
24 position, I continued my previously stated responsibilities while taking
25 responsibility for developing the annual and 5-year maintenance plans, leading all

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1 regulatory activities, negotiating contracts with the trimming vendors and
2 overseeing our planning and auditing field team. In March 2023, I accepted a new
3 role in the Company's project management organization responsible for leading the
4 long-term planning for distribution capital projects. In November 2023, I returned
5 to the Tree Trimming team to assume the Director role.

6

7 **Q5. What are your current job responsibilities?**

8 A5. Currently, I am the Director of Tree Trimming. In this role, I am responsible for the
9 strategy and execution of the Tree Trimming Program. This includes contract
10 negotiations, strategy, planning, auditing, execution, outage restoration trimming,
11 customer satisfaction, workforce development and scheduling.

12

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

15 A6. No, I have not.

Line
No.

1 **Purpose of Testimony**

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

3 A7. As referenced in Witness Kryscynski's description of the distribution witnesses, the
4 purpose of my testimony is to:

- 5 • Discuss the importance of and progress made in DTE Electric's vegetation
6 management ("Tree Trimming") program.
- 7 • Provide details related to the Company's Tree Trimming Surge Program that
8 will deliver on the reliability goals established in the Company's Distribution
9 Grid Plan (DGP).
- 10 • Describe the customer benefits of the Company's Tree Trimming Surge
11 Program to date.
- 12 • Support the Operations and Maintenance (O&M) expenses related to tree
13 trimming efforts for the historical test period ending December 31, 2022, and
14 the projected base O&M expenses and the Tree Trimming Regulatory Asset
15 Surge funding amount for January 1, 2025, to December 31, 2025.
- 16 • Request approval of incremental Surge funding for 2025.
- 17 • Discuss the future of the Tree Trimming program once the Surge is completed.
- 18 • Address the additional requests from Case No. U-21297.

19

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

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

22	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
23	A-12	B5.4	Projected Capital Expenditures – Distribution Plant
24	A-13	C5.6.1	Projected Tree Trimming Expenses
25	A-22	L1	Projected Value of Tree Trimming Surge Program

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No.

1 A-31 V1 2023 Tree Trimming Annual Report

2

3 **Q9. Were these exhibits prepared by you or under your direction?**

4 A9. Yes, they were.

5

6 **Outline of Testimony**

7 **Q10. How is your testimony organized?**

8 A10. My testimony is organized as follows:

- 9 • Overview of the Company's Tree Trimming Program and the Surge
- 10 • Discussion of the final years of the Surge
- 11 • Strategy and Vision for Post-Surge
- 12 • Additional Requests from the Order in Case No. U-21297

13

14 **Part I: Overview of the Company's Tree Trimming Program**

15 **Introduction**

16 **Q11. Can you please describe the Company's Tree Trimming Pillar of investments**
17 **within the Distribution Grid Plan (DGP)?**

18 A11. The Tree Trimming Pillar focuses on keeping vegetation (trees, brush, vines) clear
19 of our overhead electrical equipment, including poles, wires, transformers, etc. The
20 objectives of these investments are to reduce tree-related safety hazards and to
21 reduce the volume of tree-related trouble cases, thereby increasing customer
22 reliability. All vegetation management investments are made through the
23 Company's Tree Trimming Program.

24

25 **Q12. What is the biggest root cause of outages?**

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1 A12. As discussed in the Company's 2023 DGP (Case No. U-20147), tree interference
2 remains one of the leading drivers of customer outages. Historically, tree-caused
3 outages accounted for two-thirds of the time that customers spent without power.
4 The Company's Tree Trimming Program reduces the frequency of tree contact with
5 the distribution system, mitigating impact. The ongoing, successful execution of
6 this program allows DTEE to continuously improve the overall reliability of electric
7 service.

8

9 **Q13. What is the best way to reduce tree-related outages?**

10 A13. A robust Tree Trimming Program improves system reliability, including a
11 reduction of the volume and duration of outages, wire-downs, and other non-outage
12 trouble events. Achieving customers' desired level of reliability requires that the
13 program be funded to maintain a tree-trim cycle that permits the trimming of a
14 circuit to prevent vegetation interference with the Company's wires and become
15 hazards.

16

17 **Q14. What is the Company's Tree Trimming Program?**

18 A14. Beginning in 2016, the Company has executed a robust program to address tree
19 interference by trimming to an enhanced specification known as the Enhanced Tree
20 Trimming Program, or ETTP. The ETTP specification is designed to reclaim right
21 of ways, remove or reduce vegetation hazards from distribution infrastructure, and
22 properly define trim specifications for vegetation encroachment. In addition to
23 introducing this new specification, the Company proposed the Tree Trim Surge (the
24 Surge) in 2018 in Case No. U-20162. The purpose of the Surge was to secure the
25 necessary funding to trim all circuit miles to the ETTP specification by the end of

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1 2025. The Company proposed maintaining a 5-year cycle (3-year cycle for
2 Subtransmission) for all miles, including those trimmed in the early years of the
3 Surge. This means a circuit trimmed to the ETTP specification in 2016 or later
4 would be maintained on a 5-year cycle length while the Company addressed
5 additional off-cycle miles in the later years of the Surge.

6

7 **Q15. How long did the Company forecast the Tree Trim Surge would take?**

8 A15. The Company forecasted the Surge would span seven years, or 2019 through 2025.

9

10 **Q16. How much did the Company project the Surge would cost in Case no. U-**
11 **20162?**

12 A16. In Case No. U-20162, the Company projected that the Surge would cost \$1,131
13 million; \$721 million treated as base O&M and \$410 million booked as a regulatory
14 asset.

15

16 **Q17. Has the Commission supported the Tree Trimming Surge?**

17 A17. Yes, the Commission approved the first three years of regulatory asset treatment in
18 Case No. U-20162. In subsequent rate cases the Commission has continued to
19 support the Tree Trimming Surge, approving incremental years of regulatory asset
20 treatment and the requested base O&M increases.

21

22 **Q18. What is the progress towards completing the Surge as of the end of 2023?**

23 A18. The Company trimmed 5,299 miles in 2023, bringing the system to 83% on-cycle.
24 Our goal is to be 100% on-cycle by the end of 2025.

25

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1 **Q19. What does on-cycle mean?**

2 A19. On-cycle means that the circuit miles have been trimmed to the ETPP specification
3 at least once and are on a maintenance trimming cycle for future years.

4
5 **Q20. What is the Company's maintenance cycle for on-cycle miles?**

6 A20. The Company distinguishes cycle-length based on the voltage of the circuit. For
7 subtransmission circuits (24 and 40kV) the cycle length is three years. For
8 distribution circuits (4.8, 8.3 and 13.2 kV) the target cycle length has been five
9 years. The Company is introducing a variable, risk-based cycle for distribution
10 circuits, which would mean some circuits have a longer or shorter cycle length
11 based on certain criteria. This approach is discussed in detail later in this testimony.

12

13 **Q21. What does reclaim miles mean in this context?**

14 A21. Reclaim miles are circuits that have not been trimmed to the ETPP specification
15 and are considered off-cycle. These circuits have not been trimmed since at least
16 2015.

17

18 **Q22. Have the ETPP specifications been applied consistently throughout the Surge?**

19 A22. Yes. The ETPP tree-trimming specifications are applied consistently throughout
20 the Company's service territory. The Company trims and removes trees to maintain
21 circuit clearance for one five-year cycle worth of growth, which, on average,
22 necessitates ten feet of clearance to the outermost conductor. The required
23 clearance is species-specific. The specification is focused on clearing vegetation
24 within the right-of-way. In addition, while trimming a circuit the Company
25 identifies priority trees outside the right-of-way that could pose a risk and attempts

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1 to mitigate this risk. All circuits are inspected post trimming by either DTE
2 foresters or an independent third-party contractor to ensure the specifications have
3 been met. Any deviation from specification is corrected by the tree contractor who
4 performed the work at no additional cost to the Company. Further discussion of the
5 inspection process is included at the end of my testimony.

6

7 Tree Trimming Surge Effectiveness

8 **Q23. Has the Company measured the effectiveness of the Surge program thus far?**

9 A23. Yes, the Company has developed a methodology to measure the performance of
10 on-cycle circuits trimmed to the ETP specification relative to reclaim circuits.

11

12 **Q24. Can you elaborate on the methodology?**

13 A24. The Company uses the methodology outlined in Case No. U-20561 as well as in
14 the Tree Trimming Annual Reports submitted in the Case No. U-20162 docket. The
15 2023 Tree Trimming Annual Report has been submitted as Exhibit A-31, Schedule
16 V1 for reference. The report, and results mirrored below, include outage and event
17 data through the end of the 2023 calendar year.

18

19 The methodology used to calculate ETP Performance for all distribution circuits
20 uses the average of three years of pre-trim ETP tree-outage events and compares
21 it to each year post trimming. All post-trim year results of the same year were then
22 summed to increase the sample size (as an example, all post-trim year 1 results are
23 summed). The difference between the before trimming performance and the post
24 trimming performance was used to create the “% Change in Outage Event
25 Reduction for ETP circuits”. To create a control group for comparison, the same

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1 methodology was used for the remainder of circuits not trimmed ETTP¹ (Non-
2 ETTP circuits), which is identified as “% Change in Outage Event Reduction for
3 Non-ETTP circuits”. To account for natural weather variation, the performance of
4 the control group is subtracted from the ETTP circuit performance to provide an
5 accurate representation of the true impact of the ETTP.

6

7 **Q25. What has been the improvement in outage events on circuits trimmed to the**
8 **ETTP compared to the non ETTP control group?**

9 A25. The difference in outage events on ETTP circuits compared to the balance of the
10 system not trimmed to ETTP is 54.0% in post-trim year 1, 36.8% in the second
11 year, 43.8% in the third year, and 11.1% in the fourth year. The actual reduction for
12 Years 1-4 post ETTP trim are depicted in Table 1.

¹ This group consists of circuits that have not been trimmed to the ETTP specification and are considered off-cycle

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Table 1 **ETTP Tree-Related Outage Event Difference Compared to Non**

ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non- ETTP circuits	Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-22.0%	32.0%	-54.0%	-57.0%
2 Years Post Trim	1442	-12.8%	49.6%	-36.8%	-57.0%
3 Years Post Trim	974	9.9%	53.7%	-43.8%	-50.0%
4 Years Post Trim	491	58.1%	69.2%	-11.1%	-37.0%

3

4 **Q26. How does this reduction compare to results under the prior trimming**
5 **practice?**

6 A26. As discussed in Case No. U-20162, (3T 202) the past practice of trimming a
7 “clearance circle” around conductors provided only a 13% reduction in tree-related
8 events in the year following trimming as compared to the average number of events
9 in the three years preceding trimming.

10

11 **Q27. Do you see similar differences for customer interruptions and the number of**
12 **customer minutes of interruption on ETTP vs. non-ETTP circuits?**

A27. Yes. Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a

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1 57.9% difference in Year 1, 59.3% difference in Year 2, 48.6% difference in Year
2 3, and 40.7% difference in Year 4. These results are shown in Table 2. Customer
3 minutes of interruption, shown in Table 3, also show significant improvements.
4 Actual minutes of customer interruption on ETPP circuits vs. Non-ETPP circuits
5 show a 32.4% difference in Year 1, 8.1% difference in Year 2, -22.4% difference
6 in Year 3, and -6.4% difference in Year 4.

7

8 **Table 2 Post ETPP Tree-Related Customer Interruption Difference**
9 **Compared to Non ETPP Circuits**

	Number of Dist. Circuits ETPP Trimmed	% Change in Customers Interrupted for ETPP circuits	% Change in Customers Interrupted for Non- ETPP circuits	Difference in % Change in Customers Interrupted ETPP vs. Non-ETPP circuits	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-38.8%	19.1%	-57.9%	-57.0%
2 Years Post Trim	1442	-28.0%	31.2%	-59.3%	-57.0%
3 Years Post Trim	974	-24.1%	24.6%	-48.6%	-50.0%
4 Years Post Trim	491	-14.3%	26.4%	-40.7%	-37.0%

10

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1 **Table 3 Post ETTP Tree-Related Customer Minutes of Interruption**
 2 **Difference Compared to Non ETTP Circuits**

	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non- ETTP circuits	Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-27.0%	5.3%	-32.4%	-57.0%
2 Years Post Trim	1442	16.4%	24.5%	-8.1%	-57.0%
3 Years Post Trim	974	10.5%	-11.9%	22.4%	-50.0%
4 Years Post Trim	491	1.3%	-5.2%	6.4%	-37.0%

3

4

5 **Q28. What has been the reduction in wire-down events post-ETTP trimming?**

6 A28. Wire downs on the circuits that have been trimmed as part of the ETTP are
 7 significantly lower in the years after trimming compared to Non-ETTP circuits. The
 8 Year 1 difference is 55.4%, Year 2 is 56.8%, Year 3 is 39.8% and Year 4 is 15.3%.
 9 Reductions are shown in Table 4.

10

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1 **Table 4 Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits**

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	Difference in % Change in Wire-Down Events ETTP vs. Non- ETTP circuits
1 Year After Trimming	2063	-65.5%	-10.1%	-55.4%
2 Years After Trimming	1442	-64.8%	-8.0%	-56.8%
3 Years After Trimming	974	-58.3%	-18.5%	-39.8%
4 Years After Trimming	491	-52.7%	-37.4%	-15.3%

2

3 **Q29. Does the Company plan to change the way it measures effectiveness of the Tree**
4 **Trimming Program as the Surge finishes?**

5 A29. Yes. The Company recognizes the usefulness of this methodology is beginning to
6 diminish with the majority of circuits now trimmed to the ETTP specification. The
7 remaining non-ETTP population is becoming too small to be an effective
8 comparison to ETTP trimmed circuits. Moving forward the Company is exploring
9 alternative methodologies to measure tree related reliability and plans to propose
10 an alternative methodology to the Commission in a future case.

11

12

Other Components

13 **Q30. What are the other key components of the Tree Trimming Program?**

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1 A30. Other key components of the program include reactive trimming, herbicides, and
2 spot trimming.

3

4 **Q31. What is reactive trimming?**

5 A31. Reactive Trimming includes work outside of normal maintenance, storm, or
6 construction. This trimming is driven by trees that are causing an outage/non-
7 outage event and trees considered a hazard to the Company's equipment or public
8 safety.

9

10 **Q32. What is the herbicide program?**

11 A32. The Company uses EPA-regulated herbicides to replace mechanical removal of
12 vegetation from the right-of-way with a chemical treatment, which will only control
13 the tree species with the potential to grow into electrical wires. The Company has
14 created the program using industry best practices that were collected and developed
15 through benchmarking and by working with an outside consultant. The Company
16 uses herbicides that include foliar herbicide treatment, basal herbicide treatment,
17 and dormant stem treatment.

18

19 **Q33. What are the benefits of the herbicide program?**

20 A33. The herbicide treatment will reduce the future cost of maintenance trimming in the
21 right-of-way by reducing tree density. There are other advantages besides realizing
22 cost savings. As tree density and brush height decreases, the electrical system
23 becomes more reliable, and the right-of-way becomes more accessible. Also,
24 because grasses and shrubs are not affected by the herbicide treatment, the area will

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1 become a habitat for pollinators, birds, and small mammals. The treatment will
2 also target invasive plant species, limiting their spread.

3

4 **Q34. What is spot trimming?**

5 A34. Spot trimming is focused on poor performing circuits, typically not yet trimmed to
6 the ETPP specification, that have a high number of sustained and/or momentary
7 outages. Spot trimming involves targeted trimming at select trouble locations to
8 address ongoing emergent issues. ETPP trimming addresses the entire circuit and
9 the full trim specification.

10

11

Part II – Final Years of the Surge

12 **Q35. Does the Company have a projection for percentage of circuit miles that will**
13 **be on-cycle at the end of 2024?**

14 A35. Yes, at the end of 2024 the Company projects that ~90% of circuit miles will be
15 on-cycle.

16

17 **Q36. When was the Tree Trimming Surge originally proposed to be completed?**

18 A36. In Case No. U-20162 the Company proposed trimming the full system to the ETPP
19 specification and maintaining on-cycle miles to a 5-year cycle (3-year cycle for
20 subtransmission) by the end of 2025. With that goal in mind the Company expects
21 to have 10% of its system to reclaim in 2025.

22

23 **Q37. Does the Company foresee any challenges with completing the Surge based on**
24 **the funding levels and timeframe originally proposed in U-20162?**

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1 A37. As the Company has entered the final years of the Surge, we have identified a
2 funding gap to complete all reclaim miles *and* maintain on-cycle miles at the
3 intended 5-year cycle.

4
5 **Q38. How much did the Company forecast the Surge would cost in Case No. U-**
6 **20162?**

7 A38. Case No. U-20162 stated the Surge would cost \$1,131 million, \$721 million treated
8 as O&M and \$410 million booked as a regulatory asset.

9
10 **Q39. Does the Company have an updated forecast on the total cost of the Surge?**

11 A39. Yes. Based on actuals for 2019-2023, negotiated contracts for 2024, and assumed
12 costs for 2025, the Company estimates the full cost of the Surge will be \$1,383.2
13 million. This is \$251.2 million more than forecasted in Case no. U-20162.

14
15 **Q40. When did the Company understand the magnitude of the change in cost?**

16 A40. While the program has navigated a changing landscape and impacts to the cost since
17 the beginning of COVID, the magnitude of the change in cost emerged at the end
18 of 2023. This was due to the largest driver of the variance being the cost of on-cycle
19 work² being higher than originally projected. The ETP specification was
20 implemented in 2016 and the circuits trimmed in 2016 returned for their first “on-
21 cycle” trim in 2021. Subsequently we also had “on-cycle” miles in 2022 and 2023.
22 The Company has been closely monitoring the cost of these circuits relative to their
23 historical cost each year, but recognized there could be year-to-year variations.

² Referring to distribution miles trimmed to the ETP spec and due for their next trim – sub transmission has been on-cycle and costs related to that work are not the driver for the new cost projection.

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1 With the conclusion of 2023, the Company had three years' worth of on-cycle
2 actuals to project future costs of the program.

3

4 **Q41. Can the Company breakdown the drivers of the \$251.2 million incremental**
5 **cost?**

6 A41. Yes – below is a summary of the drivers.

Drivers	\$ Millions
Higher On-Cycle Costs	\$133.6
Increased Outsource Premium	\$69.7
Programmatic Additions	\$30.5
Inflation	\$17.4
Total	\$251.2

7

8 **Q42. Can you elaborate on the higher on-cycle costs driver?**

9 A42. In Case No. U-20162, the Company prepared a forecast for the seven-year Surge.
10 The Company modeled the cost to reclaim miles and cost to maintain on-cycle
11 miles in the latter years of the Surge. A key assumption of this model was that there
12 would be a 40% savings once circuits were on-cycle. For example, if a circuit cost
13 \$1 million dollars to reclaim to the ETTP specification, the next time we trim it the
14 circuit would cost \$600,000 (not adjusting for inflation). The Surge model used
15 the 40% savings assumption along with historical cost data to forecast the average
16 cost per mile for reclaim and on-cycle miles each year of the Surge.

17

18 Actuals for reclaim miles have totaled \$28 million less than the forecasted cost in
19 the Surge model. However, actuals for the on-cycle miles have totaled \$162 million

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1 more than the forecasted cost in the Surge model. In net, the cost of the miles has
2 been \$134 million more expensive than the Surge model forecast.

3

4 **Q43. Where did the 40% cost savings assumptions come from?**

5 A43. The 40% cost savings assumption was based on a work study completed by ECI, a
6 third-party consultant, between 2015 and 2017. The goals of the work study were
7 to assess use of industry management best practices within the utility, address
8 general opportunities for program enhancements, and assess program performance.
9 The work study included a field review of vegetation conditions and opportunities.
10 Through this review, ECI identified that our average density was 228 trees per mile,
11 48% of the tree work is in the backlot/in-accessible by equipment, and 42% of trees
12 were good removal candidates.

13

14 ECI recommended a maintenance program with a 5-year to 6-year cycle. Based on
15 the characteristics above and the recommended maintenance program, ECI
16 forecasted that once on-cycle the program would be 40% less than relative to the
17 reclamation period.

18

19 **Q44. Why have actual savings been less than the 40%?**

20 A44. The variance in on-cycle savings is driven by differences in ECI's assumptions and
21 the actuals we have observed in the field.

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1 **Table 5 Comparison of ECI Assumptions and Actuals**

Key Assumptions	ECI	Actuals	Commentary
Density (trees per mile)	228	242	Actual density has been ~5% higher than assumed
Backlot Work (%)	48%	80%	- Significant discrepancy in the assumed percentage of backlot work - Backlot work is majority manual climbing, which is more expensive and requires skilled trimmers
Removals Rate	42%	15% ³	ECI assumed 100% of good removal candidates would be removed

2

3 The difference in work location and removal rates means that complexity and
 4 volume of work for on-cycle trimming is higher than originally assumed, resulting
 5 in lower savings.

6

7 **Q45. Why were ECI's assumptions on removal rates and work location notably**
 8 **different from actuals?**

9 A45. ECI sampled the territory to identify total trees, good removal candidates, and work
 10 location. For removal rates, ECI assumed all trees identified as good removals
 11 would be removed during the first trimming to the ETTP specification. Customer
 12 approval is required for all removals on property. This would have meant the
 13 Company had 100% acceptance by customers to remove all these trees. At the time
 14 of study, the ETTP specification was relatively new, and the Company had limited
 15 data to understand the customer approval rate with respect to removals.

³ Removal rate for just trees, the Company's removal rate for all vegetation (trees, vines and brush) is 28%.

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1 For front vs. back lot, ECI identified trees as accessible or inaccessible. This was
2 done by surveyors who determined whether the tree could be addressed by a bucket
3 truck or other mechanized equipment. Accessibility of equipment is dependent on
4 physical ability to maneuver equipment to the tree, but also customer willingness
5 to allow for the equipment on their property, soil condition, weather and other
6 factors.

7

8 **Q46. Does the Company have improved ways to track data on removal rates and**
9 **mix of work location to assist in improved cost projections for the future?**

10 A46. Yes, the Company leverages a robust work management tool during maintenance
11 trimming in which we capture all vegetation touched as part of our annual
12 maintenance plan. For each unit (e.g., tree, brush, vine) that is addressed, we
13 document whether it is in the backlot vs. front-lot, parcel address, species, and
14 whether it's a trim or removal. Effectively, the Company is cataloging the
15 vegetation system as it is trimmed for the Surge. The work management tool was
16 implemented in 2019 and we plan to have our full system catalogued at the
17 conclusion of the Surge.

18

19 **Q47. Can you elaborate on the increased outsource premium cost driver?**

20 A47. To complete the volume of trimming needed in the Surge, the Company recognized
21 the need to pay a premium to attract outsource crews to work in the Company's
22 service territory. This premium was made up of per diems and crew overtime. In
23 Case No. U-20162, the Company forecasted the cost for the outsource premium,
24 however, actuals have exceeded the forecasted cost because we have required

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1 approximately 100 more outsource trimmers annually to supplement the local
2 workforce not growing at the forecasted rate.

3

4 **Q48. Can you elaborate on the programmatic additions?**

5 A48. Yes. There are two additions to the program that were not included in Case No. U-
6 20162's forecasts. As discussed earlier in my testimony, the Company performs
7 spot trimming on poor performing circuits that have a high number of sustained
8 and/or momentary outages. In addition, the Company created the Tree Trim
9 Academy to support growth of our local workforce and create a pipeline within the
10 City of Detroit. Operation of the Tree Trim Academy was interrupted in 2020 due
11 to the COVID-19 Pandemic but resumed in 2022. Cost impact for both programs
12 is shown in Table 6.

13

14 **Table 6 Cost of Programmatic Additions (\$ millions)**

Spot Trimming	\$26.1
Detroit Tree Trim Academy	\$4.3
Total	\$30.4

15

16 **Q49. Can you elaborate on the inflation impact?**

17 A49. The Surge model assumed an annual inflation rate of 3%. Actual costs have been
18 driven by the labor rates negotiated between IBEW Local 17 and tree trim
19 contractors. The annual labor increase for line clearance tree trim contracts ranges
20 from 4%-6% through the life of the Surge. This difference equates to \$13.6 million.
21 In addition, deferring filing a rate case for two years caused the Company to forego

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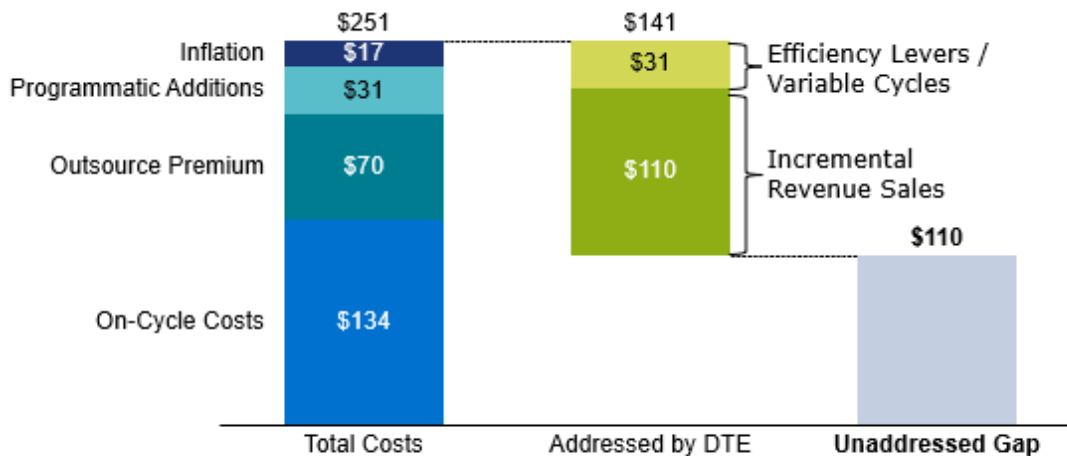
1 \$3.8M in inflation-related increases in our base O&M. The Surge model assumed
 2 the Company would engage in annual rate cases and the base O&M would increase
 3 each year.

4
 5 **Q50. How has the Company addressed the total \$250 million variance?**

6 A50. As shown in Figure 1, the Company has addressed a substantial portion of the
 7 higher costs by utilizing extra revenues collected from customers when sales were
 8 above projections and introducing variable, risk-based cycles. However, we
 9 forecast a remaining \$110 million needed to complete the Surge in totality, which
 10 equates to a 10% variance to the original cost projections for the Surge.

11

12 **Figure 1 Cumulative Cost Impact of the Surge (\$ millions)**



13 **Q51. Can you elaborate on the incremental sales revenue?**

14 A51. A substantial portion (\$90 million) of the \$110 million incremental sales revenue
 15 is associated with non-weather-related electric sales patterns resulting from the
 16 coronavirus (COVID-19) pandemic. Certain directives issued in response to the
 17 COVID-19 pandemic impacted electricity usage patterns of the Company's

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1 customers resulting in a net increase to margin compared to expectations under
2 normal circumstances. The Company proposed refunding this margin to rate payers
3 in the form of additional tree trim surge investments. The intent being to advance
4 the Company's Tree Trimming efforts while avoiding future customer expense for
5 those investments, thus providing an affordability benefit to customers. The
6 Company proposed creating a onetime regulatory liability that would be debited for
7 incremental tree trim expenses that occurred between 2021 and 2023. To the extent
8 the Company did not spend the full \$90 million by the end of 2023, the Company
9 would provide refunds to customers via bill credits. In Case No. U-21128, the
10 Commission approved the Company's proposal.

11

12 **Q52. How was the additional tree trim surge investment utilized?**

13 A52. The additional tree trim surge investment was leveraged as an immediate response
14 to the severe storm events in summer of 2021. In 2022, the Company spent \$85.8
15 million of the incremental \$90 million investment. This additional investment
16 allowed the Company to complete an extra 1,700 off-cycle miles in 2022 and lead
17 the system to be 79% on-cycle at year end. These miles were focused in poor
18 reliability areas and trimming was completed prior to the 2022 storm season. The
19 remaining \$4.2 million was committed to spot trim high-risk areas that were not on
20 the 2023 maintenance plan. In total, the Company invested \$89.4 million of the \$90
21 million, the balance of which will be credited to customer bills as proposed.

22

23 **Q53. How does the Company propose to address the remining funding needed?**

24 A53. The Company proposes to address the \$110 million through a combination of
25 incremental regulatory asset in 2025 (\$87 million) and increasing the base O&M

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1 (\$23 million) in 2026. The regulatory asset would be required to address the
2 remaining reclaim miles needed to complete the Surge. The increase in base O&M
3 is to fund trimming on-cycle miles based on the new projections. Increasing the
4 O&M for the first year post-Surge would set the appropriate baseline budget for a
5 fully on-cycle system into the future. There is further discussion of the strategy for
6 post-Surge and the opportunity to move to a risk-based, variable cycle in Part IV of
7 my testimony. Table 7 summarizes the annual funding for the final years of the
8 Surge and the first year post-Surge.

9
10 **Table 7 Proposed Incremental Funding to Complete the Surge (\$ millions)**

Funding Source	2024	2025	2026 (Post Surge)
Base O&M	\$106	\$109	\$112
<i>Incremental O&M</i>	-	-	<i>\$23</i>
Regulatory Asset	\$53	\$44	
<i>Incremental Regulatory Asset</i>		<i>\$87</i>	
Total Annual Funding	\$159	\$240	\$135
Total Incremental		\$87	\$23

11

12 **Q54. How much cost is the Company expecting to recover outside of base rates?**

13 A54. The Company is proposing to defer Surge costs up to \$183.4 million above base
14 rates from 2024 through 2025.

15

16 **Q55. How has the Company proposed to recover the program costs above base**
17 **rates?**

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1 A55. The Company proposed, and the Commission approved, regulatory asset treatment
2 for the incremental costs through 2024 totaling \$365.8 million, \$156.9 million of
3 which were securitized in March 2022 pursuant to the Commission's June 23, 2021
4 order in Case No. U-21015. Witness Lepczyk discusses how the Company proposes
5 to recover future Surge costs until they can be securitized.

6

7 **Q56. Why is the Company proposing to securitize the costs?**

8 A56. As previously discussed, the Surge investment is intended to lower future reactive
9 costs that would be incurred given the current state of vegetation near or on the
10 distribution system. Securitization funding recognizes the long-term nature of the
11 program. As the costs are incurred up front and the full savings will not be realized
12 until after the program has matured, recovery over a longer period provides a better
13 matching of costs with the anticipated savings, minimizing the cost impact to
14 customers.

15

16 **Q57. What happens if the Commission does not approve the incremental \$87 million**
17 **requested of regulatory asset?**

18 A57. Without the incremental funding, one of two scenarios will likely occur for 2025:

19 1) Scenario 1: Prioritize the reclaim miles with available funding,
20 which will limit the Company's ability to address circuits trimmed
21 to the ETPP specification that are due for their next maintenance
22 trim. The Surge would be completed, however, there is a risk of
23 historically on-cycle miles (trimmed to the ETPP specification)
24 going past their optimum next trim date which could lead to

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1 reliability problems and the cost to retrim those miles will be more
2 expensive in the future.

3 2) Scenario 2: Prioritize maintaining miles due for on-cycle trimming
4 with available funding, which results in a portion of reclaim miles
5 not to be trimmed in 2025 and carryover to 2026. The Company
6 would continue to trim the remaining reclaim miles as funds allowed
7 but would prioritize maintaining on-cycle miles.

8

9 **Q58. Can you provide more details on the impact of either of these options to the**
10 **Tree Trimming Program and electrical reliability.**

11 A58. Yes - we have identified the following adverse impacts:

12 1) Scenario 1 – Approximately 3,200 on-cycle miles that are due for
13 trimming would not be addressed. This would cause trimming
14 expense to increase by 20% the following year. Further, an impact
15 to reliability performance would result for circuits identified as fast
16 growth archetypes.

17 2) Option 2 – Based on the 2024 plan, approximately 2,600 reclaim
18 miles will remain at the beginning of 2025. If the Company
19 prioritizes on-cycle miles with the current funding, we estimate
20 being able to address up to 700 of the remaining 2,600 miles of
21 reclaim. The reliability impact to the 1,900 miles unable to be
22 trimmed would be increased by approximately 20%. The average
23 age since last trim of these miles in 2025 would be 11.5 years. In
24 addition, the Company would need to defer ~500 on-cycle miles that
25 are due in 2025, to 2026.

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1 **Part III – Post-Surge (2026 and beyond)**

2 **Q59. Can you define “post-Surge”?**

3 A59. As DTEE enters 2024, the penultimate year of the Surge, the Company is beginning
4 to plan for what the Tree Trimming Program will look like once it is fully on-cycle,
5 beginning in 2026, defined as the “post-Surge” period. This definition assumes that
6 DTEE completes all the reclaim miles by the end of 2025.

7
8 **Q60. What funding level does the Company forecast the program will need post-
9 Surge?**

10 A60. The Company forecasts the program will require approximately \$135 million
11 annually (not adjusted for inflation) to maintain the Surge’s investment and keep
12 all miles on-cycle.

13
14 **Q61. How does this funding level compare to the forecast from prior cases?**

15 A61. As shown in Table 8, the DTEE forecasts the Tree Trim Program will cost an
16 incremental \$23 million annually relative to the amount that the Company
17 originally forecasted in Case No. U-20162. In Case Nos. U-21297 and U-20836,
18 the Company submitted exhibit A-22 Schedule L1. This exhibit is an output of the
19 Surge model which projects the future O&M needs of the program – the exhibit
20 indicated expected O&M for the program after the Surge was trending higher than
21 the projections from Case No. U-20162. As discussed previously, the full
22 magnitude of the increased costs were not fully understood until last Fall.

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1

Table 8 Forecasted O&M Post-Surge (\$ millions)

Source of Projection	2026	2027	2028
U-20162	\$112	\$116	\$119
U-20836/U-21297	\$126	\$130	\$133
Current Projected Costs	\$135	\$139	\$142

2

3 **Q62. Why will the post-Surge program cost more than originally forecasted?**

4 A62. As discussed previously, the Company has determined that the on-cycle cost of
5 trimming is more than it forecasted in Case No. U-20162.

6

7 **Q63. Beyond requesting incremental O&M, how does the Company plan to address
8 the on-cycle cost pressures?**

9 A63. In Case No. U-21297, the Company introduced its effort to develop a risk-based,
10 variable cycle model. The model was developed to elevate the Company's
11 maintenance trimming cycle to be more targeted than the current 5-year standard.

12

13 **Q64. Why is the Company exploring a risk-based, variable cycle currently?**

14 A64. As the Company enters the final years of the Surge, the Company recognizes that
15 there are opportunities to adjust the target cycle for different parts of the system
16 utilizing technology such as LiDAR. Adjusting cycle lengths based on tree species'
17 growth rates, risk of outages, and cost of trimming will further improve trimming
18 efficiencies and provide reliability benefits to customers. With the acquisition of
19 LiDAR tree density and encroachment data combined with tree species data the
20 Company has acquired over the course of the Surge program, DTE Electric has the
21 necessary information to make data-driven improvements to the program.

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1 Furthermore, the idea of variable cycles was raised by intervenors and the
2 Commission in Case No. U-20836. In Case No. U-20836 (p.487), the Commission
3 ordered the Company to continue to explore efficiency improvements, and benefits
4 from a variable cycle for the Tree Trimming program and the Company is
5 complying with that directive.

6

7 **Q65. What is LiDAR and why is it beneficial to the Tree Trimming program?**

8 A65. LiDAR (Light detection and ranging) is a remote sensing method that measures the
9 distance to Earth of different objects, such as trees and utility equipment. LiDAR
10 enables the development of a 3D image of an area with accurate measurements
11 between objects and the ground. In recent years, LiDAR has emerged as a valuable
12 tool for vegetation management programs to digitalize assets and assess risk to the
13 system.

14

15 **Q66. Does the Company have experience with LiDAR technology?**

16 A66. Yes. The Company has developed a risk-based, variable cycle model that leverages
17 the LiDAR data to help identify optimal trim cycles and emerging hot spots. LiDAR
18 technology provides advanced data on the Company's tree density, growth patterns
19 and emerging cycle-buster trees. This data can also provide significant value to the
20 Tree Trimming program in the form of assisting in scoping and estimating costs for
21 maintenance work.

22

23 **Q67. How is a risk-based cycle different from a 5-year cycle?**

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1 A67. A fixed-year cycle (i.e., 5-year cycle) has been the industry standard until recently.
2 The emergence of remote sensing and advanced data analytics for vegetation
3 programs allows companies to begin considering variable cycles.

4
5 Moving towards a variable, risk-based cycle would be a refinement to the
6 Company's maintenance trimming program. The 5-year cycle is based on the
7 average growth rates and tree densities across the entire system and their expected
8 average spatial relation to the conductor. There are areas across the territory with
9 higher tree densities and faster growing species that grow back into the wires prior
10 to five years, in other words there are variances to the averages discussed.
11 Conversely there are areas with slower growing species that could go longer
12 between maintenance trims before interfering with the conductor. Moving towards
13 a risk-based cycle would move higher risk areas to a shorter-cycle, and lower risk
14 areas to a longer-cycle, instead of uniformly trimming every area on a 5-year cycle.

15

16 **Q68. Do other utilities use a risk-based cycle?**

17 A68. Yes. Based on my understanding of benchmarking and other information, the
18 Company has identified other utilities in the industry exploring or introducing
19 variable, risk-based variable cycles.

20

21 **Q69. What does the Company foresee as the benefit from this shift?**

22 A69. The Company expects that moving towards a risk-based cycle will result in
23 trimming efficiencies and improved reliability for high-risk areas. Based on the
24 nature of variable cycle programs, the Company anticipates the need to trim high-
25 risk areas more frequently, and low-risk areas less frequently, resulting in an overall

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1 more efficient use of resources. In addition, more frequent trimming in high-risk
2 areas should provide reliability benefits to customers, without sacrificing reliability
3 in low-risk areas.

4

5 To best understand the benefits and potential tradeoffs from a variable, risk-based
6 cycle, in 2024 the Company identified approximately 2,000 miles of on-cycle
7 circuits that could go a year past the 5-year cycle based on the results of its risk-
8 based model. This sample of variable cycle circuits will allow the Company to
9 measure the potential benefits of risk-based cycles such as improved trimming
10 efficiencies, lower annual trimming costs and improved reliability. In addition, the
11 Company will be able to identify potential challenges, develop countermeasures,
12 and adjust the model.

13

14 **Q70. How did the Company determine the length of a risk-based cycle?**

15 A70. The Company developed a risk prioritization model that leverages remote sensing
16 data (e.g., LiDAR), advanced analytics, and machine learning to estimate the
17 probability of vegetation-driven failures and determine optimal trim cycles for an
18 area.

19

20 **Q71. What was the investment for the risk prioritization model?**

21 A71. The direct capital investment for this model is approximately \$6.3 million.

22

23 **Q72. Is the Company seeking recovery for this investment?**

24 A72. Yes. The Company is seeking recovery for this investment as shown in Exhibit A-
25 12, Schedule B5.4, Page 17, line 24 (\$6.9 million).

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1 **Q73. Are there other elements of the model?**

2 A73. Yes. Beyond identifying optimum trim cycles for different areas, the model will
3 provide key improvements to the Company's annual planning and execution of the
4 maintenance plan.

5 (1) This model will expand and enhance the cost modeling the Company
6 has already done using LiDAR data and circuit system data. This
7 information together can identify efficiency opportunities through
8 mechanization identification in accordance with trim location⁴.

9 (2) The model identifies where trimming work for overlapping
10 distribution and sub transmission lines can be optimized to drive
11 efficiencies and optimize trim cycles in areas with multiple classes
12 of distribution assets.

13 (3) The model will improve the process for developing the annual plan
14 by automating the balance of work across the territory to ensure
15 capacity of work is within control limits⁵.

16

17 **Q74. Will the use of the risk-based cycle reduce the Company's forecasted funding**
18 **needs post-Surge?**

19 A74. Yes, the Company's forecasted need of \$135 million annually assumes that the
20 Company will be on a risk-based, variable cycle. If the Company does not move to
21 a risk-based cycle, then the cost of maintaining the program at a 5-year cycle will
22 be higher. We assume risk-based cycles will yield a minimum of a 5% savings
23 annually during initial transition to variable cycles.

⁴ In this context *mechanization identification* refers to the practice of employing equipment, such as backyard buckets or Jarraffs, in areas that historically used manual climbing.

⁵ Control Limits is a point of reference for balancing volume of work based on service center, resources, budget, and other operational constraints.

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Part IV: Additional Requests from Order Case No. U-21297

3

Q75. Has the Company been Ordered to consider other changes to the Tree Trimming program?

4

5

A75. Yes, in Case No. U-21297 (December 1, 2023, Order, page 353) the Commission directed the Company to consider a future residential service drop Tree Trimming pilot and to work with the Staff to develop such a pilot to be considered in the Company's next rate case.

6

7

8

9

10 **Q76. What is a service drop?**

11

A76. Generally, a service drop is the term used for an overhead secondary conductor running from a utility pole, across a customer's property, to a meter installed on a home (for a typical residential customer).

12

13

14

15 **Q77. How does a service drop differ from other types of overhead distribution wires?**

16

17

A77. Most overhead distribution wires run from one utility pole to another, whereas service drops run from pole to a customer's structure. Utilities typically have a right of way (ROW) for the areas surrounding their pole-to-pole wires that permits them to trim vegetation near those conductors. The Company does not have the same right of way for service drops.

18

19

20

21

22

23 **Q78. Does the Company have a service line Tree Trimming maintenance program for service drops?**

24

25

A78. No, the Company does not.

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1 **Q79. Is the Company developing a pilot to trim services?**

2 A79. Yes. The Company is working with Staff and at least one intervenor to develop a
3 pilot utilizing the expedited pilot process.

4

5 **Q80. Were there additional tree trim related directives in the December 1 Order in**
6 **Case No. U-21297?**

7 A80. Yes, in Case No. U-21297 (Page 353) the Commission adopted Staff's
8 recommendations regarding tree-trimming audits (inspections) and an analysis of
9 more aggressive trimming in zones 2 and 3.

10

11 **Q81. Does the Tree Trimming Program include auditing (inspections)?**

12 A81. Yes. The Tree Trimming program performs quality inspections on all maintenance
13 work to ensure compliance to specifications outlined by the ETP.

14

15 **Q82. How is the inspection conducted and to what standards?**

16 A82. An inspection is conducted to quality standards determined by ISA and ANSI300A
17 trimming guidance against the trim plan for that specified work completed on a
18 circuit. The inspection is performed by a certified arborists who are either internal
19 to the Company or a 3rd party vendor who is not associated with the Tree Trimming
20 vendors.

21

22 **Q83. When does inspection take place?**

23 A83. Inspections are conducted typically less than 30 days from the time the entirety of
24 the work for all circuits from a substation is completed. Once all the work is
25 reviewed and approved by the arborist the closure of that work is approved.

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1 **Q84. What happens when a non-compliant result is discovered?**

2 A84. Any non-compliance of a tree trim task according to plan against the standard is
3 provided to the trimming vendor to be remediated within 30 days, at no additional
4 cost to the Company. An auditor then inspects the area again to ensure the
5 remediation is performed in a satisfactory manner.

6

7 **Q85. How does the Company track tree work associated with the maintenance**
8 **program and the quality inspections?**

9 A85. The Company has a work management system that is used for the planning,
10 execution, and inspection of all maintenance trimming. This program allows for
11 planners to identify specific tasks (trims or removals by tree / brush) on a property,
12 which the trimmers reference and use for their work plan execution. The inspection
13 team uses the same system to identify the work that was completed and inspect the
14 tasks for potential defects. Inspection results are then accessible to the contractor
15 through the work management system. This process allows for streamlined plans,
16 electronic records of work completed, and a database of tree work for the Company
17 to leverage for future planning and analysis.

18

19 **Q86. What is Zone 2 and Zone 3 and how do they differ from Zone 1 from a**
20 **trimming specification?**

21 A86. The Company divides the overhead electrical system into three zones. In Zone 1,
22 the portion of the circuit from the substation to the first protective device or drop
23 down, the Company removes all branches overhanging the conductors. In Zone 2,
24 the portion of the circuit from the first protective device or drop down⁶ to the fused

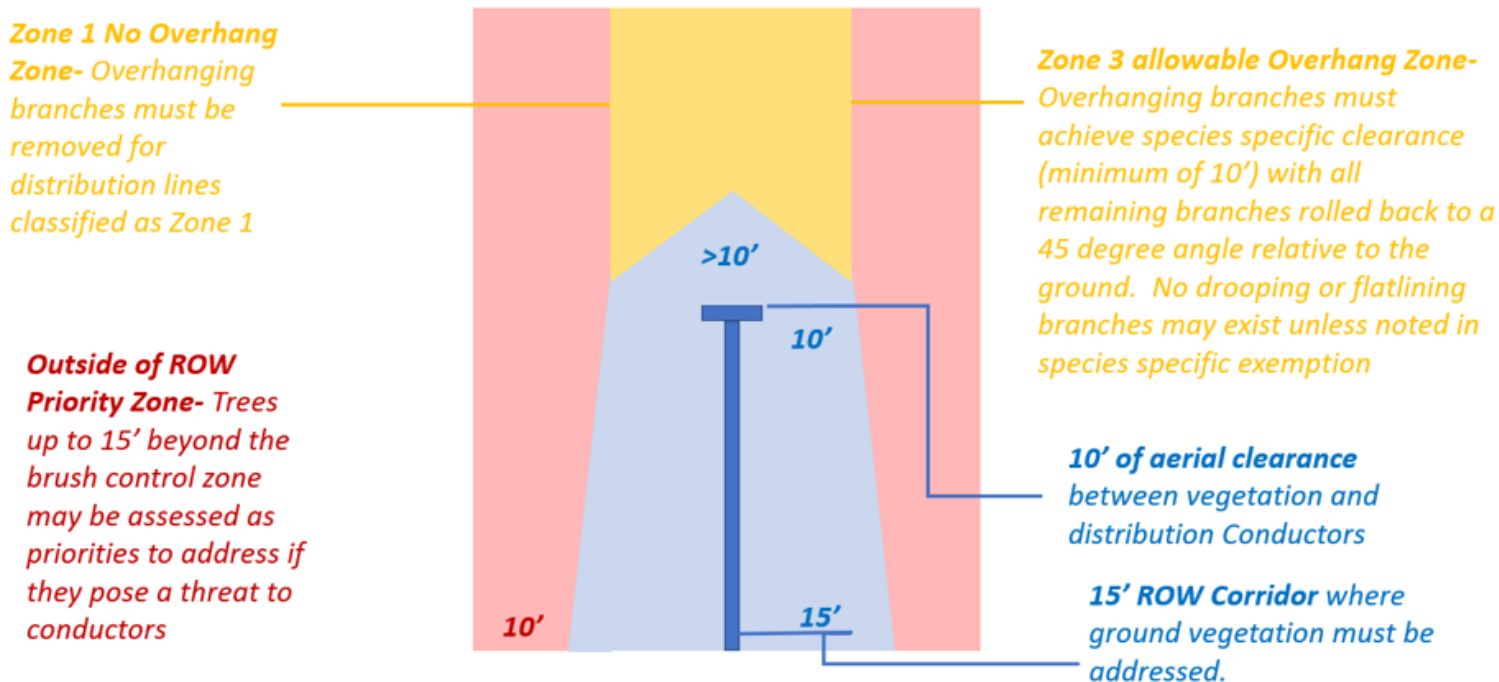
⁶ Drop Down is designated as a location on the circuit where a voltage drop or a multiple direction split in distribution power takes place.

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1 lateral, and in Zone 3, the fused laterals, the Company removes all softwood and
2 hardwood branches overhanging the conductors at less than a forty-five-degree
3 angle. The difference in specification is illustrated in Figure 2.

4

5 **Figure 2 Trimming Specification for Zone 1 compared to Zone 2/3**



6

7 **Q87. What would more aggressive trimming of Zone 2 and Zone 3 look like from a**
8 **specification perspective?**

9 A87. If the Company were to trim these zones more aggressively, it would be trimming
10 all areas to the Zone 1 specification, which requires removing all overhang.

11

12 **Q88. Could the Company pilot the impact of more aggressive trimming in Zone 2**
13 **and Zone 3?**

14 A88. While the Company could perform a pilot, the appropriate timeframe to fully
15 understand the costs and benefits of this type of change would be to track a subset

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1 of circuits for 4-5 years after trimming to fully measure reliability benefit relative
2 to circuits trimmed to our current maintenance specification. If we were to pilot
3 trimming all zones to the same specification on several circuits this year (2024), we
4 would need to compare those circuits' performance through 2029 to fully measure
5 the potential reliability benefit.

6

7 **Q89. Does the Company have an alternative methodology to study the incremental**
8 **benefit and cost of expanding the trimming on Zone 2 and Zone 3?**

9 A89. The Company proposes comparing circuits trimmed on our regular maintenance
10 program (control group) to circuits trimmed for construction projects (test group).
11 The Company has a small subset of circuits that have been trimmed to a more
12 expansive specification, with all overhang removed, in preparation for construction
13 projects. The Company can compare the cost and reliability of these two groups to
14 understand the impact of potentially changing the specification.

15

16 **Q90. Are there other considerations beyond cost and reliability if the Company**
17 **were to change the specification for Zone 2 and Zone 3?**

18 A90. Yes:

19 1) The Company anticipates customer sentiment would be impacted
20 negatively by pulling overhang on Zone 2 / Zone 3. Typically, the portion
21 of the overhead line that runs through a customer's backyard / property is
22 Zone 2 / Zone 3. Comparatively, Zone 1 is often referred to as the backbone
23 and may be along the roadside or in a less residential setting, therefore less
24 direct impact to customers.

Line
No.

2) Pulling additional overhang would require more skilled climbing trimmers and acquisition of specialty trim equipment in areas where large mature trees are present.

3) By trimming overhang, that historically hasn't been removed, undergrowth and brush will be exposed to additional sunlight, expediting existing growth and creating new vegetation growth under the wires. This could lead to further maintenance costs and interfere with anticipated reliability improvement.

10 Conclusion

11 **Q91. Does this complete your direct testimony?**

12 A91. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

RACHEL C. STEUDLE

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF RACHEL C. STEUDLE

Line
No.

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

3 A1. My name is Rachel Steudle, Director of Tree Trimming, One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Electric Company, known simply as DTE.

5

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

8 A2. Yes.

9

10 **Purpose of Testimony**

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

12 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
13 other parties as follows. The absence of a discussion of other matters in my
14 testimony should not be taken as an indication that I agree with all other aspects of
15 intervenor testimony.

16 • Attorney General (AG) Witness Coppola's recommendation to disallow
17 capital, regulatory asset and O&M related to the Tree Trim program,

18 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
19 Resource Defense Council (NRDC), collectively AG-MN Witness
20 Alvarez's and Citizens Utility Board of Michigan, Michigan Environmental
21 Council, and Natural Resources Defense Council, collectively CUB-MN
22 Witness Denzler's recommendations around future data / analysis to be
23 provided by the Company,

24 • Ann Arbor Witness Giacobazzi's commentary on tree trimmers identifying
25 methane leaks while trimming,

Line
No.

- 1 • AG-MN Witness Alvarez's and Ann Arbor Witness Stultz's general
2 mischaracterizations of the Company's tree trimming program,
3

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

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

6	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
7	A-42	Schedule GG1	Emergent Capital Savings Calculation
8	A-42	Schedule GG2	Tree Trim Risk Model NPV
9	A-42	Schedule GG3	AGDE-4.167(S1)
10	A-42	Schedule GG4	AGDE-4.160a
11	A-42	Schedule GG5	DEAG-2

12

13 **Part 1 - Recommended Disallowance by Witness Coppola**

14 Capital Disallowances

15 **Q5. What is the AG Witness Coppola's recommendation with regards to**
16 **accounting for Tree Trim Surge savings?**

17 A5. Beginning on page 33, line 19 and running through page 34, line 2 of his direct
18 testimony, AG witness Coppola recommends the Commission remove \$66.9
19 million in cost savings from the Company's forecasted capital expense in 2024 and
20 \$59.6 million in 2025 due to his calculation of savings arising from the Tree Trim
21 Surge program.

22

23 **Q6. Does the Company agree with the recommended disallowance in Capital?**

24 A6. No.

Line
No.

1 **Q7. Does the Company agree that the Tree Trim Surge will result in emergent**
2 **capital savings?**

3 A7. Yes.

5 **Q8. Did the Company account for these savings with respect to emergent capital?**

6 A8. Yes. In Exhibit 12, Schedule B 5.4, p. 1, line 6, the Company reduces the requested
7 emergent capital for 2024 by \$20.8 million and for 2025 by \$21.4 million, reflecting
8 the expected savings we will see from both tree trim and non-tree trim investments
9 in strategic capital.

10

11 **Q9. How did the Company determine these amounts?**

12 A9. These outputs came from the Company's Reliability Model. Witness Kryscynski
13 discusses the model in detail in his direct testimony beginning on page 69, line 8.
14 The model itself has also been provided as WP AJK U-21534 Reliability Model.

15

16 **Q10. How does the Reliability model calculate expected savings?**

17 A10. The model includes a circuit-by-circuit average event volume based on circuit
18 performance from 2018-2022. The model includes both tree-related and non-tree
19 related event volumes. When tree trim or other reliability investments are
20 performed on a circuit, the model assumes the event volume on that circuit
21 decreases. Circuits with no reliability investments will experience an increase in
22 event volume. Events also have an average cost per event based on historical
23 averages. The model calculates expected savings by taking the difference from the
24 baseline event volume (2018-2022 average) and the modeled event volumes in
25 2024 and 2025.

Line
No.

1 **Q11. How does Witness Coppola determine his recommended disallowance?**

2 A11. Witness Coppola points to the Company's response in discovery in which the
3 Company was asked to compare the relative cost savings expected to be realized
4 by executing the Surge, versus not executing the Surge (page 33, line 13-19).
5 Specifically, this discovery relies on data presented in U-21534 Exhibit A-22.
6

7 **Q12. What is the purpose of U-21534 Exhibit A-22?**

8 A12. U-21534 Exhibit A-22 is an output of the Tree Trim Surge model which was
9 developed as part of Case No. U-20162 to demonstrate the relative benefit for the
10 Tree Trim Surge compared to a status quo scenario of not executing the Surge.
11

12 **Q13. What is the status quo scenario?**

13 A13. The status quo scenario assumes the Company did not receive the Surge funding.
14 In this scenario, the Company is limited in the number of miles it can reclaim
15 annually and is unable to fully maintain on-cycle miles as they return for trimming.
16

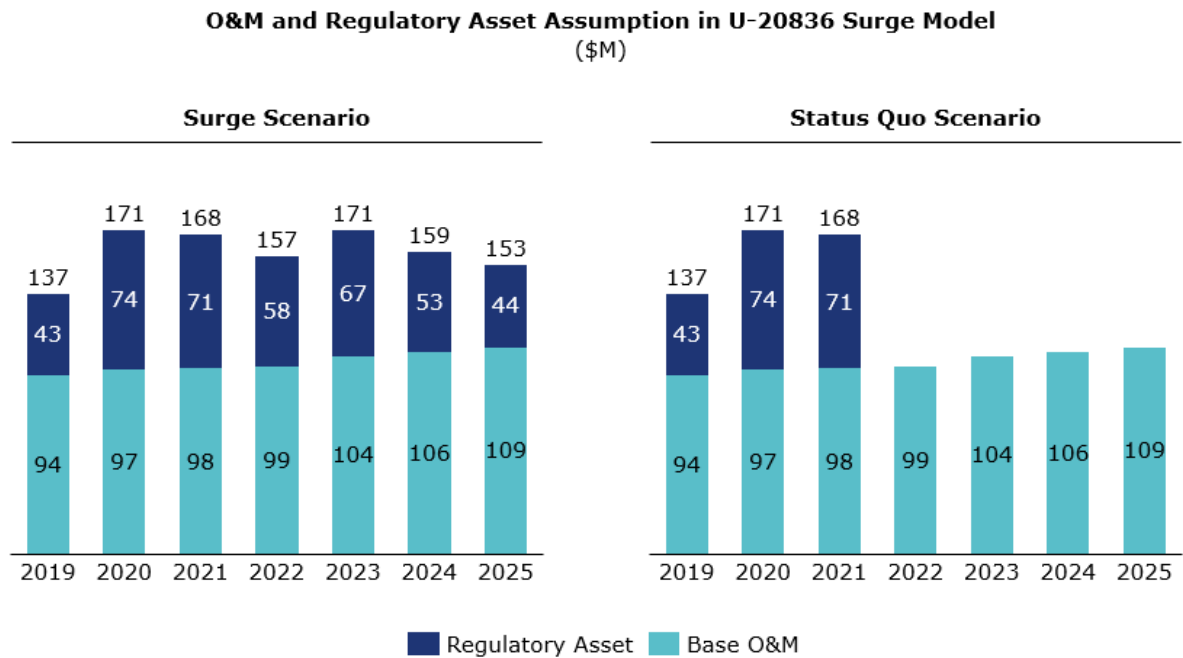
17 **Q14. When was U-21534 Exhibit A-22 last updated?**

18 A14. Exhibit A-22 was updated for Case No. U-20836 to justify the continued support
19 of the Surge program beyond 2021. Since the Company had already received
20 approval for the regulatory asset for 2019-2021, this version of the model compared
21 the relative difference in continuing the Surge for 2022 onward compared to
22 discontinuing the Surge at the end of 2021. Figure 1 shows the annual funding
23 assumptions used in the model and how the divergence takes place in 2022.

Line
No.

1

Figure 1 Base O&M and Regulatory Asset Assumption in U-20836



2

3 **Q15. Can the data provided in Exhibit A-22 be used to calculate the relative savings**
4 **from the Tree Trim Surge model?**

5 A15. Yes – the model projects the expected emergent capital costs for both the Surge and
6 Status Quo scenarios. Using the projected costs under the Surge scenario, the
7 Company could calculate an expected reduction in emergent capital relative to the
8 historic year of 2022.

9

10 **Q16. Using this methodology, what would be the projected emergent capital cost**
11 **savings for 2024 and 2025?**

12 A16. The cost savings would be \$22.8 million in 2024 and \$30.1 million in 2025. Please
13 refer to Exhibit A-42, Schedule GG1 for the detailed walk of this calculation.

Line
No.

1 **Q17. How does this compare to the cost savings the Company used (\$20.8 million**
2 **for 2024 and \$21.4 million in 2025)?**

3 A17. The Tree Trim model shows about \$11 million more in savings. The difference in
4 the projected savings is due to the models using different baselines and the
5 reliability model accounting for the system degradation. The Tree Trim Model
6 Surge used a baseline of 2018-2020. The Reliability Model used a baseline of 2018-
7 2022 to account for more recent actuals.

8

9 **Q18. Do you agree with using the emergent savings as they were provided in Exhibit**
10 **A-12?**

11 A18. Yes – based on the discussion above, Exhibit A-12 appropriately accounts for the
12 emergent capital savings arising from the Tree Trim program using the most
13 accurate and current data available.

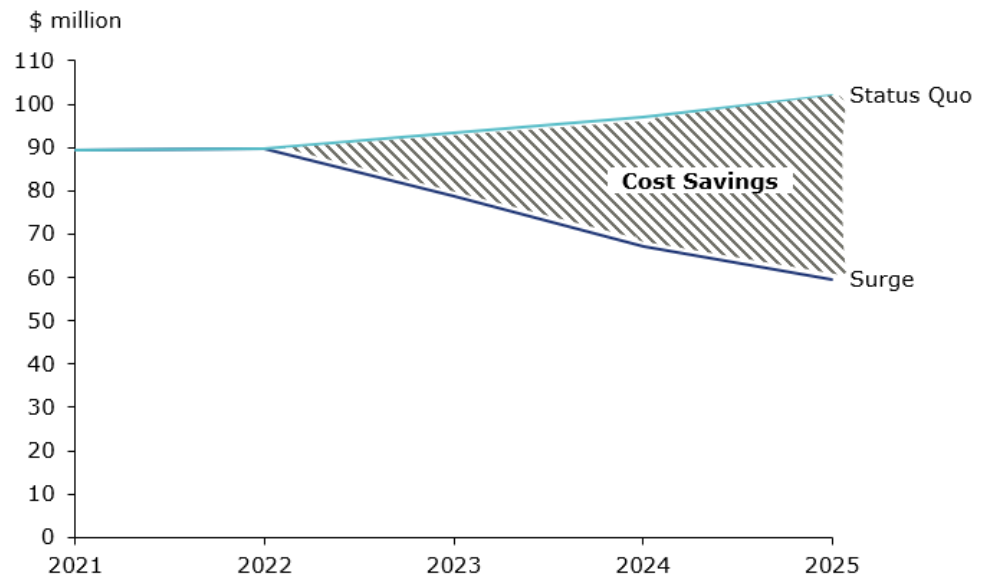
14

15 **Q19. How does Witness Coppola determine the recommended emergent capital**
16 **disallowance?**

17 A19. Witness Coppola uses a discovery response from the Company in which the request
18 is to compare the relative cost savings between the Surge Scenario and Status Quo
19 Scenario in Exhibit A-22. Figure 2 provides a visual representation of these cost
20 savings. In this approach, the cost savings is the relative reduction the Company
21 forecasted by continuing the Surge from 2022 through 2025 compared to a status
22 quo scenario in which the Surge stopped at the end of 2021.

Line
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1 **Figure 2** **Forecasted Emergent Capital Costs of Executing the Surge vs**
2 **Status Quo**



3

4 **Q20. Is this an appropriate method to determine the cost savings the Company will**
5 **realize in 2024 and 2025?**

6 A20. No. As discussed previously, the Surge model and Exhibit A-22 were last updated
7 to compare continuing the Surge in 2022 versus discontinuing it at the end of 2021.
8 Since the Company has *continued to execute the Surge*, the Status Quo line in
9 Figure 2 would align with the Surge line, therefore suggesting no relative savings
10 between the two scenarios.

11

12 Witness Coppola requested this methodology in discovery, the Company
13 inadvertently provided the wrong data in its discovery response named AGDE-
14 4.167, provided in Exhibit A-42, schedule GG3. The question in which the mistake
15 occurred was used by Witness Coppola to make his recommendation on page 33,

Line
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1 line 13 through 19, and due to this error on Company's part, the dollar amounts
2 Witness Coppola provided are wrong. The discovery question from the AG
3 requested an update to a discovery request from multiple prior rate cases. The
4 Company has submitted a supplemental response to AGDE-4.167, with the correct
5 cost savings of continuing the Surge compared a scenario in which the Surge was
6 terminated at the end of 2021.

7

8 **Q21. Does Witness Coppola recommend additional capital disallowances related to**
9 **the Company's Tree Trimming activities?**

10 A21. Yes – Witness Coppola recommends disallowing \$6.9 million of capital investment
11 related to the development of the Tree Trim Risk Prioritization Model.

12

13 **Q22. What is the Tree Trim Risk Prioritization model?**

14 A22. The Company developed a risk prioritization model that leverages remote sensing
15 data (e.g., LiDAR), advanced analytics, and machine learning to estimate the
16 probability of vegetation-driven failures and determine optimal trim cycles for an
17 area. This model would enable the Company to use risk-based cycles for
18 maintenance trimming rather than a fixed-year cycle, thus optimizing tree trimming
19 based on specific vegetation characteristics that differ across areas of the
20 Company's service territory. Further discussion of the benefits of the risk-based
21 cycles can be found in my direct testimony beginning on page 28.

22

23 **Q23. Why does Witness Coppola recommend disallowing this investment?**

24 A23. Witness Coppola stated the following on page 73, line 1-5.

25 *"I recommend that the Commission remove the \$3,078,000 in capital*
26 *expenditures for 2022 and the \$3,824,000 for 2023 pertaining to the*

Line
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1 *Tree Trim Risk Prioritization model because the Company did not*
2 *perform a cost/benefit analysis and did not justify that the model and*
3 *related expenditures are economically beneficial to customers.”*
4

5 **Q24. Did the Company perform a cost/benefit analysis for the model?**

6 A24. Yes, in Case No U-21297 the Company performed this analysis and included it as
7 Exhibit A-22, Schedule L2. I have included that analysis with my rebuttal
8 testimony as Exhibit A-42, Schedule GG2.
9

10 **Q25. What was the result of this analysis?**

11 A25. The discounted cash flow NPV for the risk prioritization model was \$11.2 million.
12

13 **Q26. Did Witness Coppola provide commentary or recommendations on this**
14 **investment in the Company’s 2023 rate case, U-21297?**

15 A26. No.
16

17 **Q27. Do you agree with the recommendation to disallow this investment as part of**
18 **this case?**

19 A27. No – for several reasons.

20 1. The capital costs for the Tree Trim Risk Prioritization model were included
21 in the prior case (Case No. U-21297) and not disputed by any party nor
22 disallowed by the Commission. The Company has already spent this capital
23 and has the functional model that we’re using.
24

25 2. The Company performed the cost/benefit analysis and requested these funds
26 in the last case and demonstrated a positive NPV for the tool.

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1 3. Furthermore, the idea of variable cycles was raised by intervenors and the
2 Commission in Case No. U-20836. In Case U-20836 (page 487), the
3 Commission ordered the Company to continue to explore efficiency
4 improvements, and benefits from a variable cycle for the tree trimming
5 program. In turn, the Company has complied with that directive by
6 developing the model.

7

8 Regulatory Asset Disallowances

9 **Q28. What is Witness Coppola's recommendation regarding the Company's**
10 **requested incremental regulatory asset request for 2025?**

11 A28. Witness Coppola recommends the Commission reject the request for an additional
12 \$87 million in deferred costs in 2025 for the Surge program.

13

14 **Q29. How does Witness Coppola justify this recommendation?**

15 A29. He provides a variety of reasons summarized below:

- 16 • The Company has not demonstrated the effectiveness of the Tree Trim
17 Surge (page 68, line 7 through page 69, line 2),
18 • The Company mischaracterizes the investment already made in the Tree
19 Trim Surge (page 67, line 6-12),
20 • The Company should have known and escalated the need for incremental
21 funding prior to this case (page 69, line 3 through 10),
22 • The justification for the specific components that lead to the need for more
23 funding was not sufficient (specifically the Company's payments of
24 outsource premiums (page 69, line 11 through page 70, line 4), investment

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1 in the Detroit Tree Trim Academy (page 70, line 8-19), and the impact of
2 tree removals on costs (page 71, line 1 through 10)).
3

4 **Q30. Does the Company believe the Tree Trim Surge has been effective in providing**
5 **reliability benefits?**

6 A30. Yes. As demonstrated in the Tree Trimming Surge Effectiveness section of my
7 direct testimony (beginning on page 8), circuits that have been trimmed to the ETPP
8 specification experience a significant improvement in reliability compared to the
9 circuits off-cycle and not yet trimmed as part of the Surge program.
10

11 **Q31. Witness Coppola points to the severe storm and other large weather events of**
12 **2023 as the test for measuring whether the increased tree trimming is making**
13 **a difference (page 68, line 7 through page 69, line 2). Do you agree that 2023**
14 **should be used as the test for the Surge's effectiveness?**

15 A31. No. When the Company measures the effectiveness of the Tree Trim program,
16 weather is normalized to account for variability in year-to-year events. This annual
17 variability was exacerbated in 2023 when the Company experienced five
18 catastrophic storms, including the most damaging winter ice storm in Company
19 history, and another summer catastrophic storm event that included heavy damage
20 from a historic six tornadoes.
21

22 The 2023 winter ice storm was especially challenging from a tree damage
23 perspective. The ice was almost ¾ inches thick in many areas and the weight of the
24 ice severely damaged trees, wires, equipment, and poles. This type of weather
25 phenomena causes significant damage to healthy trees that would not fail under

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1 typical weather events. Company Witness Hill discusses the severity of the 2023
2 weather events in further detail in his direct testimony, including pictures of large
3 trees that failed due to the ice (page 11).

4

5 **Q32. Do you agree with Witness Coppola's statement that the Company has**
6 **invested \$496 million in capital programs related to Tree Trimming, therefore,**
7 **the total cost of the Surge should be considered upwards for \$1.9 billion?**

8 A32. No, I do not agree for two reasons. First, the Company did not recognize the \$496
9 million as dollars associated with the Surge. When asked in discovery, Witness
10 Coppola explained it is the total capital costs related to Tree Trim that occurs as
11 part of emergent capital (Exhibit A-22, line 27).

12

13 **Q33. What is included in those capital costs?**

14 A33. The capital costs are related to emergent work, broken up into three categories.

Cost Category	Description	Total Provided by AG in Discovery DEAG-2 ¹	Exhibit A-22 Line Number
Tree Trim Reactive Capital	Trimming related to emergent events (non-Storm)	\$12.3	24
Tree Trim Storm Capital	Trimming related to restoring customers during storms	\$112.6	25
Other DO Tree- related Capital	Overhead (linemen) labor and equipment costs of restoring tree related outages	\$371.2	26

15

16 Most of the costs are "Other DO Tree-related capital" which reflect the cost for
17 lineman and field personnel to restore outages caused by trees. Those dollars are

¹ See Exhibit A-42 Schedule GG5 - DEAG-2

Line
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1 not associated with trimming trees. The costs associated with trimming trees are
2 reflected in “Tree Trim Reactive Capital” and “Tree Trim Storm Capital” and are
3 specific to restoring customers and/or mitigating hazards. Crews are not trimming
4 to the maintenance specification and therefore these costs do not drive progress to
5 completing the Surge.

6

7 **Q34. What is the second reason including the \$496 million is not appropriate?**

8 A34. Capitalized tree trimming costs have appropriately never been included in the Tree
9 Trim Surge program. Tree trimming that is capitalized is performed to support
10 construction projects such as 4.8kV hardening, Pole and Pole Top Management and
11 Modernization (PTMM), 4.8kV conversions, and distribution automation.

12

13 **Q35. Why does Witness Coppola believe that the Company should have known the**
14 **cost of the Surge was higher prior to 2023?**

15 A35. Witness Coppola uses the data provided in discovery response AGDE-4.159d to
16 demonstrate that the Company’s cost per mile for reclaiming circuits (trimming to
17 the ETTP specification for the first time) increased by 41% between 2021 and 2022,
18 suggesting the Company should have had indications that tree trimming was
19 costing more than planned.

20

21 **Q36. Do you agree that the 2022 reclaim costs should have been used as an**
22 **indication of funding challenges?**

23 A36. No, the average cost per mile by itself for any given year is an incomplete picture,
24 because that average can vary year-to-year based on the volume of work required
25 by the unique vegetation characteristics of each specific circuit. In 2022, the cost

Line
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1 of reclaim circuit miles was high because of the areas in which we focused our
2 trimming. In 2022, the Company prioritized several key communities that were
3 significantly off-cycle compared to our system average. These communities were
4 also ones significantly impacted for the 2021 weather events and the Company
5 recognized the need to focus reclaiming these areas to improve reliability for those
6 impacted customers.

7

8 The tree work in these areas was more dense and intensive, therefore expensive
9 than in years past and drove up the overall average for 2022. The average cost for
10 reclaim circuits reduced by 20% in 2023, validating that 2022 was an outlier.

11

12 **Table 1 Average cost per mile of reclaim miles**

	2019	2020	2021	2022	2023
Distribution Reclaim \$/Mile	\$ 29,403	\$ 29,375	\$ 28,507	\$ 43,695	\$ 35,086

13

14 **Q37. Does Witness Coppola raise specific concerns with the cost drivers that have**
15 **impacted the Surge?**

16 A37. Yes, he raises issues with the Company's practice of securing outsource crews
17 through paying premiums, investments made in the Detroit Tree Trim academy and
18 the gap in actual tree removals.

19

20 **Q38. What is the outsource premium?**

21 A38. The outsource premium refers to dollars the Company has paid to attract and retain
22 outsource tree trimming crews. Specifically, these payments are a daily per diem
23 and overtime.

Line
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1 **Q39. What is an outsource trimmer?**

2 A39. An outsource trimmer is not a local resident of our service territory. These trimmers
3 travel across the country, performing utility line clearance on different properties.
4 While on DTE Electric's property, the Company has paid a competitive per diem
5 to retain the necessary workforce for the Surge. In addition, the Company has
6 offered 60-hour work weeks for maintenance trimming (20-hours of overtime).
7 This schedule is attractive to outsource trimmers as they are interested in
8 maximizing the workweek as they do not have a family or permanent residence in
9 the area.

10

11 **Q40. Why are outsource trimmers necessary?**

12 A40. Supplementing our local workforce with outsource crews was necessary to quickly
13 ramp up the trimming resources when the Surge was approved in 2019. The tree
14 trim budget increased by over 50% from 2018 to 2019. To train a fully qualified
15 line clearance tree trimmer takes multiple years. Further, the workforce has been in
16 high demand across the county as many utilities are increasing their vegetation
17 management programs. Leveraging outsource trimmers has also allowed the
18 Company to modify workforce year-to-year as the funding levels of the Surge have
19 fluctuated.

20

21 **Q41. In Case No. U-20162, did the Company account for needing outsource**
22 **trimmers?**

23 A41. Yes, the Company anticipated needing to ramp up the trimming workforce quickly
24 to meet the commitments of the Surge and included costs associated with paying
25 the outsource premium as part of the forecasted cost of the Surge.

Line
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1 **Q42. Has the actual outsource premium exceeded the forecast?**

2 A42. Yes, the Company anticipates paying \$69 million more in outsource premiums than
3 forecasted in Case No. U-20162 for the full length of the Surge.

4

5 **Q43. Why have actuals exceeded forecast?**

6 A43. The Company has required more outsource trimmers than anticipated – driven
7 predominately by the local workforce not growing at the expected rate. The slow
8 local-workforce growth can be attributed to disruption created by the COVID-19
9 pandemic. Many workforce development efforts were paused in 2020 due to the
10 pandemic creating a hole in the woodsmen pipeline. Further, the dynamic of the job
11 market shifted coming out of the pandemic, meaning individuals seeking entry-
12 level jobs had many opportunities, especially if they had a CDL (Commercial
13 Driver's License), a required credential for trimmers on DTE's property.

14

15 **Q44. What commentary does Witness Coppola provide around the outsource
16 premium?**

17 A44. Witness Coppola suggests the Company should take corrective actions against
18 paying our current four contractors the outsource premiums and eliminate these
19 costs in 2024 and 2025 (page 70, line 1-4).

20

21 **Q45. Do you agree with this characterization?**

22 A45. No, the number of contractors does not drive the amount of outsource premiums
23 paid; it is driven by the number of outsource trimmers we have on property². The
24 Company has had on average 390 outsource trimmers on property to support the

² With respect to the tree trimming workforce, the term "on property" means a full time equivalent largely dedicated to work on behalf of the Company.

Line
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1 Tree Trim Surge. The per diem is a direct pass through to the outsource trimmers,
2 and the overtime premium is reflective of the Local-17 wage structure we pay to all
3 our trimmers.

4

5 **Q46. Do you agree with Witness Coppola's recommendation that the Company**
6 **needs to take corrective actions to mitigate/eliminated the costs for 2024 and**
7 **2025?**

8 A46. No, while the Company will continue to look for solutions that can lower the cost
9 of tree trimming, if the Company were to stop paying these premiums mid-way
10 through 2024 and continue to do so into 2025, we would significantly jeopardize
11 the completion of the Surge.

12

13 **Q47. Has the Company taken action to support development of the local workforce?**

14 A47. The Company is participating in three programs in an effort to increase the number
15 of local trimmers. The three programs are the IBEW Local 17 Traditional Boot
16 Camp, the Parnall Correctional Facility Vocational Village Training Program, and
17 the City of Detroit Tree Trim Academy.

18

19 1. Traditional Boot Camp – IBEW holds regularly scheduled boot camp training
20 for apprentices. Camps are conducted at their training facility in Wales, MI.

21 2. Parnall Correctional Facility – The Parnall Tree Trimming program is designed
22 to provide returning citizens the skills needed to start as an apprentice tree
23 trimmer. DTE has partnered with the Michigan Department of Corrections to
24 provide qualified instructors and the required training support within the prison
25 facility before participants are released.

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1 3. Tree Trim Academy – The Company has partnered with the City of Detroit,
2 IBEW Local 17, and its tree-trimming contractors to develop and implement a
3 pre-woodsman training program to satisfy the demand for qualified tree
4 trimmers. The tree trimming academy is located within the City of Detroit and
5 facilitates training that is aimed at preparing local resident candidates to work
6 as woodsmen. Once candidates complete the pre-woodsman program,
7 graduates enter the traditional IBEW boot camp.

8

9 **Q48. How much has the Company invested in the Detroit Tree Trim Academy?**

10 A48. The Company will have invested \$4.3 million in the Detroit Tree Trim Academy
11 through the course of the Surge (2019-2025).

12

13 **Q49. Does Witness Coppola support the Company's investment in the Detroit Tree**
14 **Trim Academy?**

15 A49. No, Witness Coppola miscalculates the retention rate for the program as 33% and
16 then inappropriately concludes it should not be considered a success (page 70, line
17 14). "The Company should look at either significantly restructuring the program to
18 at least double the retention rate or, if that goal is not achievable, shut down the
19 academy and reassign those dollars to hiring trained tree trimmers or not spend
20 them at all." (Coppola direct, page 70, line 16-19)

21

22 **Q50. What is the correct retention rate for the Academy?**

23 A50. Since 2021, 56% of the students who have been placed with a tree contractor
24 continue to work as tree trimmers on property. This is the number of trimmers still

Line
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1 with a tree vendor divided by the number of candidates originally placed with a tree
2 vendor.

3

4 **Q51. Should this retention rate be seen as a success?**

5 A51. Yes, absolutely. Historically, only 30% of trimmers who began the traditional
6 bootcamp successfully progressed through the full apprenticeship. Academy
7 graduates who were placed on property are almost twice as likely to continue
8 through the apprenticeship, compared to candidates who do not participate in the
9 Academy.

10

11 **Q52. Are there other benefits from the Tree Trim Academy?**

12 A52. Yes, along with growing the local workforce, the Academy was developed in
13 Detroit to increase diversity in the tree trimming workforce *and* provide career
14 opportunities to the local community. Of the graduates, 71% are people of color
15 and 36% are Detroit residents.

16

17 **Q53. How much does the Company plan to invest in the Tree Trim Academy in**
18 **2025?**

19 A53. The Company plans to continue with an annual investment of ~\$700k in 2025.
20 Witness Coppola misstates the planned investment for 2025, arguing against “the
21 *additional* \$4.1 million that the Company wants to allocate to it in 2025.” (Coppola
22 direct testimony, page 70, lines 15–16) The Company provided the annual
23 investments in the Academy, including the forecasted amount for 2025 in discovery
24 response AGDE-4. The Company is providing that response as Exhibit A-42 Sch
25 GG4. It shows a *total* spend for 2025 of approximately \$700k, not \$4.1 million,

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1 and a cost for the period of 2019 through 2025 of \$4.3 million. The dollars spent
2 on this Academy benefits the Company, its customers, and their communities.

3

4 **Q54. What does Witness Coppola say with respect to the Company's historical**
5 **removal rates?**

6 A54. In addition to trimming trees, the Company targets removing some trees within our
7 right-of-way as part of the maintenance trimming program. Witness Coppola raises
8 concerns with the Company's annual removal rate targeted vs actual being between
9 38%-48%. Targeted trees are defined as a good removal candidate, based on the
10 Company's trimming specification which prioritizes removing smaller, faster
11 growing trees.

12

13 **Q55. Why is the Company not removing more trees that are good removal**
14 **candidates?**

15 A55. To remove a tree, a customer must provide signed permission. The Company
16 currently will make multiple attempts to contact customers/property owners to
17 discuss and obtain signed permits. The Company is committed to achieving the
18 necessary line clearances to ensure safety and improvement in reliability for
19 customers. While this commitment requires that the Company obtain the necessary
20 clearances through trimming, removing trees provides additional benefits in terms
21 of reliability and future costs, however, the impact and pushback from some
22 customers can be significant. To that end, the Company is currently examining a
23 more progressive approach to remove trees that are deemed hazardous to the safety
24 and reliability of the circuits. This is an area where Commission's support will be
25 very beneficial to improving the safety and reliability/resiliency of the grid,

Line
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1 especially considering the more frequent extreme weather conditions we are
2 experiencing.

3

4 **Q56. Do you believe the requested \$87 million in regulatory asset is a prudent and**
5 **justified request?**

6 A56. Yes, the Company has performed extensive analysis to understand the drivers for
7 the gap in funding the Tree Trim Surge and closed the majority of the shortfall
8 without requesting incremental support. The requested \$87 million is essential to
9 both complete the Surge *and* keep on-cycle miles trimmed and maintained.

10

11 O&M Disallowances

12 **Q57. What is Witness Coppola's recommendation with regards to accounting for**
13 **Tree Trim Surge Savings with respect to O&M emergent savings?**

14 A57. On page 106, line 6 through 7 of Witness Coppola direct testimony it is
15 recommended the Commission remove \$8.8 million in cost savings from the
16 Company's forecasted O&M expense due to savings by the Tree Trim Surge
17 program.

18

19 **Q58. Does the Company agree that the Tree Trim Surge will result in O&M**
20 **savings?**

21 A58. Yes.

22

23 **Q59. Does the Company agree with the \$8.8 million O&M reduction proposed by**
24 **Witness Coppola?**

Line
No.

1 A59. No. Based on Witness Coppola's Exhibit AG-40, the \$8.8M is the net difference of
2 the total calculated O&M savings (\$17.6 million) and what was already included in
3 Exhibit A-13, Schedule C 5.6 (\$8.8 million).

4

5 That \$8.8 million difference represents the cost savings for the Tree Trim Reactive
6 line item. These costs are included in Exhibit A-22, Schedule L1, line 4 and
7 therefore the savings between the historical year and the projected test period are
8 already accounted for. The table below summarizes how the total O&M cost
9 savings were calculated and where those savings are realized.

10

11

Table 2 O&M Savings

Cost Category	O&M Savings (million)	Where are savings accounted for?
Tree Trim Reactive	\$8.8	Savings are realized as part of the Tree Trim Surge budget and reflected in Exhibit A-22, Schedule L1
Tree Trim Storm	\$5.0	Savings are realized outside of the Tree Trim Surge budget and reflected in Exhibit A-13, Schedule C 5.6
Other DO-Service Operations	\$3.8	
Total	\$17.6	

12

13 **Part 2 – Recommendations made by AG-MN Witness Alvarez and CUB-MN**

14 **Witness Denzler**

15 **Q60. What recommendations does AG-MN Witness Alvarez provide related to the**
16 **Tree Trim program?**

Line
No.

1 A60. Witness Alvarez recommends the Commission include the following items in their
2 decision for this case (page 8, line 13-21):

- 3 • Order an audit of the Company's rights-of-way every 5-years
4 • Require the Company to identify the extent it has capitalized tree trimming
5 costs in PTMM, 4.8kV Hardening, 4.8kV Conversions and Distribution
6 Automation

7
8 **Q61. Why does Witness Alvarez recommend the rights-of-way audit?**

9 A61. He believes the audit is necessary to ensure the Company adheres to vegetation
10 management moving forward and does not fall off-cycle. (Alvarez direct, page 42,
11 line 12 through page 43, line 10)

12

13 **Q62. Does the Company agree that the audit is necessary?**

14 A62. No. Paying for a third-party audit of the Company's rights-of-way is redundant to
15 existing activities, which are more cost-effective and timely ways for the
16 Commission and others to monitor the Company's future commitments to and
17 progress on maintaining the tree trimming program.

18

19 **Q63. Can you elaborate on the existing activities?**

20 A63. Yes.

21 The Company performs 100% inspection audits of the miles trimmed each year to
22 ensure we are obtaining the necessary clearances. Details of the inspection process
23 are included in my direct testimony on page 34, beginning line 11.

Line
No.

1 The Company supports the continued submission of the Tree Trim annual report –
2 which provides a summary of the miles trimmed and dollars invested in tree
3 trimming each year.

4 The Company also submits monthly data as part of the requested reliability data to
5 Staff – this information provides insight into the Company’s tree trimming progress
6 against the annual maintenance plan.

7

8 **Q64. Witness Alvarez suggests that the Company should be required to provide**
9 **information about the capitalization of tree trimming costs. (Alvarez direct,**
10 **page 38, lines 14 – 15) Has the Company provided this type of data in the past?**

11 A64. The Company provides the capitalization costs associated with 4.8kV Hardening,
12 which is the majority of tree trim capitalization costs, in the Tree Trim Annual
13 Report that is included as an exhibit in this case.

14

15 **Q65. Are there additional recommendations regarding Tree Trim from other MN**
16 **witnesses?**

17 A65. Yes. CUB-MN Witness Denzler recommends the Commission require the
18 Company to perform an audit/review of the Tree Trim Prioritization model to
19 measure its accuracy and compare it to alternative models offered by third parties.

20

21 **Q66. Does the Company believe it is necessary to compare the prioritization model**
22 **to alternative, third party models?**

23 A66. No, the Company has already invested in the current model, and as discussed
24 earlier, believes it will provide positive benefits to customers. The Company does
25 not see it as prudent to invest in additional tools at this time.

Line
No.

1 Instead, the Company is prioritizing using and testing the existing model to defer a
2 subset of miles due for trimming based on a five-year cycle. The Company will
3 perform both field- and data-based reviews of how these deferred circuits
4 performed from a reliability and future cost to trim perspective.

5

6 **Part 3 – Rebuttal to testimony by Ann Arbor Witnesses**

7 **Q67. Does Witness Giacobazzi raise any concerning topics related to the tree trim**
8 **program?**

9 A67. Indirectly yes – Witness Giacobazzi discusses the impact of underground methane
10 leaks on trees (page 7, line 8-15). Witness Giacobazzi seems to suggest an
11 expectation that the Company’s tree trimmers should be noting tree damage specific
12 to methane leaks and reporting it to the City of Ann Arbor.

13

14 **Q68. Do you believe tree trimmers should be expected to report potential methane**
15 **leaks?**

16 A68. No, this expectation is beyond the scope of training provided in the Tree Trimming
17 program, and to include this type of identification into our maintenance program
18 would require additional training and process development. The Company does not
19 consider this to be a prudent expectation of a program focused on ensuring the safe
20 and efficient clearing of vegetation from around our overhead infrastructure.

21

22 **Part 4 – Concluding Commentary**

23 **Q69. Are there any final themes that emerged in intervenor testimony that you**
24 **would like to address?**

Line
No.

1 A69. Yes, witnesses for both Ann Arbor and AG-MN implied that the Company neglects
2 its tree trimming efforts.³

3

4 **Q70. Do you agree?**

5 A70. No, since the beginning of the Surge, the Company has demonstrated its
6 commitment to the Surge and the importance of tree trimming. At the end of 2023,
7 our system was 83% on-cycle, and the city of Ann Arbor was 95% on-cycle.
8 Further, the Company has demonstrated additional commitment for the program by
9 providing incremental funding, i.e., the incremental \$90 million in 2022/2023.

10

11 **Q71. Is there other witness testimony you would like to address?**

12 A71. Yes, AG-MN Witness Alvarez states “DTE admits that more frequent tree
13 trimming – for the most part an O&M expense, not capital spending – is the most
14 effective thing DTE can do to improve reliability, stating ‘in areas where tree
15 trimming has been completed, communities have experienced, on average, 60%
16 fewer outages.’” Page 16, line 7 through page 17, line 1.

17

18 **Q72. Do you agree with this statement?**

19 A72. No, I find three mischaracterizations in this statement. The first is that achieving
20 our reliability goals and ensuring safe, reliable service for our customers requires
21 that the Company to take a holistic, multipronged approach to improving our grid.
22 Trimming trees and vegetation, and maintaining our rights-of-way is an important
23 piece, but as supported by witness Kryscynski in his rebuttal testimony beginning
24 on page 7, are not the only investments the Company need to make. Trimming the

³ Ann Arbor Witness Stults page 19, line 1-4; AG-MN Witness Alvarez page 42, lines 18 – 19:

Line
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1 trees will not change the age or condition of our equipment – that requires robust
2 capital investments.

3

4 **Q73. What are the other two mischaracterizations by Witness Alvarez?**

5 A73. It is unclear the exact source of the “more frequent” statement, however, I would
6 like to clarify that the Company believes regular, on-cycle maintenance trimming
7 is critical to the Tree Trim program. Generally, we believe this means a five-year
8 cycle with the opportunity to adjust circuits as we continue to leverage the Tree
9 Trim Prioritization model to move to an optimized, variable-cycle.

10

11 Finally, Witness Alvarez generalizes the 60% improvement statistic to downplay
12 the improvements from strategic capital programs. As discussed in my direct
13 testimony, the Company looks at the effectiveness of the Tree Trimming program
14 specific to *tree-related* events. The most recent effectiveness data demonstrates
15 circuits trimmed to the ETPP specification experience 58% fewer *tree-related*
16 customer interruptions (RCS 11, line 9) relative to circuits not trimmed to the ETPP
17 specification. Further details on the tree trim effectiveness methodology can be
18 found on RCS 8 Line 13 through RCS 9 line 5.

19

20 **Q74. Does this conclude your rebuttal testimony?**

21 A74. Yes, it does.

1 JUDGE WALLACE: O.K. Please continue.

2 MS. REITZEL: Thank you. DTE would now
3 move to bind into the record the Direct Testimony of
4 Brian L. Hill, which consists of a cover sheet and 33
5 pages of questions and answers. Mr. Hill also has two
6 direct exhibits and schedules designated as Exhibit A-12
7 Schedule B5.4, and Exhibit A-23 Schedule M4. There is
8 also rebuttal testimony, consisting of a cover sheet and
9 31 pages of questions and answers, as well as three
10 rebuttal exhibits, designated as Exhibit A-52 Schedule
11 QQ1, Exhibit A-52 Schedule QQ2, and Exhibit A-52 Schedule
12 QQ3.

13 JUDGE WALLACE: Is there any objection to
14 binding in the direct and rebuttal testimony of Mr. Hill?

15 Hearing none, the testimony is bound in.

16 Is there any objection to the admission
17 of the exhibits and associated schedules sponsored by
18 Mr. Hill? (No response.)

19 (Testimony bound in.)

20 - - -

21

22

23

24

25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
BRIAN L. HILL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF BRIAN L. HILL

Line
No.

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

2 A1. My name is Brian L. Hill (he, his, 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 graduated from Michigan State University Eli Broad College of Business. I
11 graduated with a Bachelor of Arts Degree in Materials & Logistics Management
12 with a focus on Operations Management. I received a Juris Doctorate (JD) Degree
13 from the University of Detroit Mercy School of Law. I have also completed several
14 Company sponsored courses and attended various seminars to further my
15 professional development, including Lean Six Sigma Certification.

16

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

18 A4. I began my career in the automotive industry working for Johnson Controls; a
19 world-wide Tier 1 OEM supplier. I worked there from 1994-2008 where I held a
20 series of positions in materials, operations, and plant management. In my plant
21 manager role, I was responsible for all aspects of the business including safety,
22 operations, engineering, quality, materials, finance/accounting, continuous
23 improvement, and human resources. The plant employed approximately 400
24 people comprised of both salaried employees and UAW union members. My
25 employment with DTE began in October 2008 as the Logistics Manager in Energy

Line
No.

1 Supply. Between January 2011 and November 2012, I was the Senior Supply Chain
2 Manager at the Fermi 2 Nuclear Power Station where I held responsibility for
3 warehousing, procurement, contracts, and work management. These activities
4 were essential to supporting safe, reliable, and efficient plant operations, including
5 refueling outages. Between December 2012 and March 2015, I was a Director in
6 Corporate Services where I held increasing leadership responsibility in the Center
7 of Excellence, Supplier Performance Management, and Facilities Operations. In
8 this role I was responsible for strategic planning, operational metric reporting,
9 safety strategy, resource planning, financial forecasting, and continuous
10 improvement. I was also responsible for the long-term and daily operations of
11 facilities management, including asset management. Between April 2015 and
12 October 2016, I was the Director of Tree Trimming in the Distribution Operations
13 organization of DTE Electric. In this role I was responsible for leading the strategic
14 development and implementation of the Enhanced Tree Trim Program. In addition,
15 I was responsible for Tree Trim Operations, comprised of DTE Energy employees
16 and tree trim contractors (comprising over 500 employees in 2016). In this role, I
17 was responsible for safety, quality, productivity, customer satisfaction, storm and
18 trouble restoration efforts, and relationships with municipalities. In November
19 2016, I started my current role as the Director of Scheduling and Coordination in
20 the Distribution Operations organization of DTE Electric. During this time, I was
21 also responsible for the Project Management Office from November 2016 until
22 June 2022 where I managed a large portfolio of projects and programs for
23 Distribution Operations that included planning and construction. In October 2023,
24 I was assigned the Director position for Southwest Regional Customer Operations
25 and Scheduling & Coordination.

Line
No.

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

3 A5. Yes. I am a Licensed Attorney in the State of Michigan and a Lean Six Sigma
4 Black Belt.

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

7 A6. My responsibilities as Director Southwest Regional Customer Operations and
8 Scheduling & Coordination include six primary areas: 1) Southwest Regional
9 Customer Operations, 2) Overhead & Underground Scheduling, 3) Substations
10 Planning & Scheduling, 4) Work Management, 5) Billing, Unitization, and
11 Inspection, and 6) Safety, Human Performance, and Hazardous Energy Control.
12 These organizations are briefly described below:

14 Southwest Regional Customer Operations: Lead over 800 full-time and contract
15 employees responsible for engineering, planning, maintaining, operating,
16 constructing, and improving the electrical system to ensure the delivery of safe,
17 reliable electric service. The Southwest region has three service centers located in
18 Newport, Belleville, and Ann Arbor that serve approximately 605,000 customers.

20 Overhead & Underground Scheduling: This organization schedules all planned
21 work for both DTE and contractor field crews on overhead and underground sub
22 transmission and distribution assets.

Line
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1 Substations Planning & Scheduling: This organization plans and schedules all work
2 for both DTE and contractor field crews on substations assets. The team also
3 includes field contractor oversight for substation construction and modifications.

4
5 Work Management: This organization leads systematic approaches to track and
6 measure work as well as streamline both business processes and routine tasks. The
7 team governs the Maximo Business Process that coordinates team collaboration and
8 workflows across all levels of the organization.

9
10 Billing, Unitization, and Inspection: This team is responsible for contractor
11 accounts payable & invoicing, unitization of capital investments, and conducting
12 field quality inspections to validate construction is built to standards and
13 specifications.

14
15 Safety, Human Performance, and Hazardous Energy Control: This team includes
16 subject matter experts (SMEs) in the areas of electrical safety, human performance,
17 and hazardous energy control (red tag/lock out tag out). The SMEs are responsible
18 for procedures, training, and governance of these safety programs.

19

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

22 A7. Yes. I sponsored testimony in Case No. U-21297. In addition, I supported witness
23 testimony related to the enhanced tree trimming program in prior rate cases.

Line
No.

1 **Purpose of Testimony**

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

3 A8. My testimony supports, as reasonable and necessary, the historical capital
4 expenditures and proposed capital expenditures related to base capital programs
5 (emergent replacements, customer connections, relocations, and others). My
6 testimony also provides an explanation of the Company's purchase and use of
7 Portable Generators (included in Exhibit A-12, Schedule B5.4, page 13, line 28
8 under Infrastructure Resilience and Hardening Pillar) and an update on Miss Dig
9 (which is not a capital program or expenditure) reporting changes made since Case
10 No. U-21297.

11

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

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

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-12	B5.4	Projected Capital Expenditures – Distribution Plant
16			(Pages 1-8 & 13-22)
17	A-23	M4	Distribution Plant Capital Project Detail –
18			Base Capital

19

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

21 A10. Yes, they were.

22

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

24 A11. My testimony consists of the following four parts:

25 Part I Emergent Replacements

Line
No.

1 Part II Customer Connections, Relocations & Other

2 Part III Portable Generators

3 Part IV Miss Dig

4

5 **Parts I & II: Base Capital Programs**

6 **Q12. Can you please summarize what is included in Distribution Operations Base**
7 **Capital Programs?**

8 A12. Capital investments in base capital programs are summarized on Exhibit A-12,
9 Schedule B5.4, pages 1 and 2, including Emergent Replacements on lines 2 through
10 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with
11 additional details on page 3 for Emergent Replacements and pages 4 through 8 for
12 Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4
13 for base capital programs are AFUDC on page 19 and plant activity starting on page
14 20. Base capital programs are further supported on Exhibit A-23, Schedule M4.

Line
No.

1 **Part I: Emergent Replacements**

2 **Emergent Replacements – Storm**

3 **Q13. Generally, what is included in Emergent Replacement – Storm?**

4 A13. This category includes investments required to restore the overhead and
5 underground distribution systems, the sub-transmission system, and substations
6 from damage and outages occurring during weather events called “storms.” A
7 storm is defined as greater than 760 customer outage events (an outage event is
8 when customers are left without power) impacting greater than 200 circuits. These
9 investments are necessary and prudent to restore customers’ power by replacing
10 damaged equipment that caused customer outages and/or public hazards.
11 Examples of equipment that are typically replaced in a storm include poles,
12 crossarms, and conductors, which are most often damaged by weather and tree
13 impacts. When poles and power lines break, they can result in customer power
14 outages and wire downs that create potential public safety hazards.

15

16 **Q14. What is the Emergent Replacement – Storm expenditure forecast for 2023**
17 **through 2025?**

18 A14. At the time the 2023 storm expenditures were estimated for use in the instant case,
19 prior to the end of 2023¹, the Company forecasts the 2023 Emergent Replacement
20 – Storm expenditures to be \$282 million (Exhibit A-12 Schedule B5.4, page 1, line
21 3, column (c)). This forecast is higher than the 5-year historic inflation adjusted
22 average of \$230 million for the time-period 2018 through 2022 (Exhibit A-12
23 Schedule B5.4, page 3, line 5, column (g)). The 2023 storm expenditures were
24 higher than the 5-year average because the company and our customers experienced

¹ Unless otherwise noted, in this testimony 2023 forecasts are based on eleven months of actuals (January through November) with December being an estimate.

Line
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1 significant storm events in 2023. 2023 included five catastrophic storms, including
2 the most damaging winter ice storm in Company history, and another summer
3 catastrophic storm event that included heavy damage from historic six tornadoes.
4 Storm expenditures for 2024 and 2025 are forecasted at \$244 million and \$251
5 million, Exhibit A-12 Schedule B5.4, page 2, line 3, columns (f) and (g),
6 respectively, based on a 5-year inflation adjusted historic average of the period
7 2018-2022.

8

9 **Q15. Why is the Company forecasting 2024 and 2025 Storm expenditures using a 5-**
10 **year inflation adjusted historic average?**

11 A15. DTEE is using a 5-year inflation adjusted historic average to forecast 2024 and
12 2025 because this method is consistent with Commission Orders in the Company's
13 previous rate cases, specifically Case Nos. U-20162, U-20561, Case No. U-20836,
14 and Case No. U-21297. The Company agrees with the Commission that this
15 method smooths out the variable impact of storms from year-to-year.

16

17 **Q16. How is the Company reflecting the impacts of the actions it is taking to offset**
18 **inflationary pressures in the emergent category?**

19 A16. The Company is offsetting inflationary expenditures in emergent investments based
20 on strategic capital investments and the Tree Trim (TT) Surge program. This offset
21 is shown in Exhibit A-12 Schedule B5.4, page 2, line 6 and is \$21 million for
22 Calendar Year (CY) 2024 and \$21 million for CY 2025. These avoided
23 expenditures are calculated using the Company's reliability model as discussed by
24 Company Witness Kryscynski.

25

Line
No.

1 **Q17. Are there any investments planned by DTEE Information Technology (IT)**
2 **that support the Company's storm processes?**

3 A17. Yes, there are three DTEE IT investments that support the Company's storm
4 processes. These investments are the Storm Data Lakehouse, the Storm Simulation
5 Lab, and the Storm Cloud. All associated investments and benefits for these
6 projects can be found in Exhibit A-12 Schedule B5.7.4 and B5.7.7 which are
7 sponsored by Company Witness Sharma.

8

9 **Catastrophic Storms of 2023**

10 **Q18. Can you describe the number and nature of the storms that impacted the**
11 **Company's service territory in 2023?**

12 A18. Between January and August of 2023, the Company experienced seven storm
13 events. Driving investment expenditures in the emergent category, five of these
14 seven storms events (71%) were Catastrophic (CAT) in nature and amongst the
15 most damaging in Company history. The frequency and intensity of these CAT
16 storms resulted in a frustrating year of outages for our customers, and a significant
17 amount of storm restoration work for the Company.

18

19 The seven storm events included two level 1 catastrophic CAT-1 storms and three
20 level 2 catastrophic CAT-2 storms. A CAT-1 storm is defined as 110,000
21 customers or more without power in a 24-hour period (5% of total customers
22 affected). A CAT-2 storm is defined as 220,000 customers or more without power
23 in a 24-hour period (10% of total customers affected). The largest of these storms
24 occurred on February 22nd, 2023 and left more than 675,000 of the Company's
25 customers without power. Due to the extensive damage caused by the February ice

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1 storm, combined with the intensity and the frequency between the four summer
2 CAT storms, all storm damage could not be fully repaired before the next extreme
3 weather event hit our service territory. This left the electrical system in an abnormal
4 condition with many temporary repairs that made it more susceptible to damage in
5 subsequent storms.

6

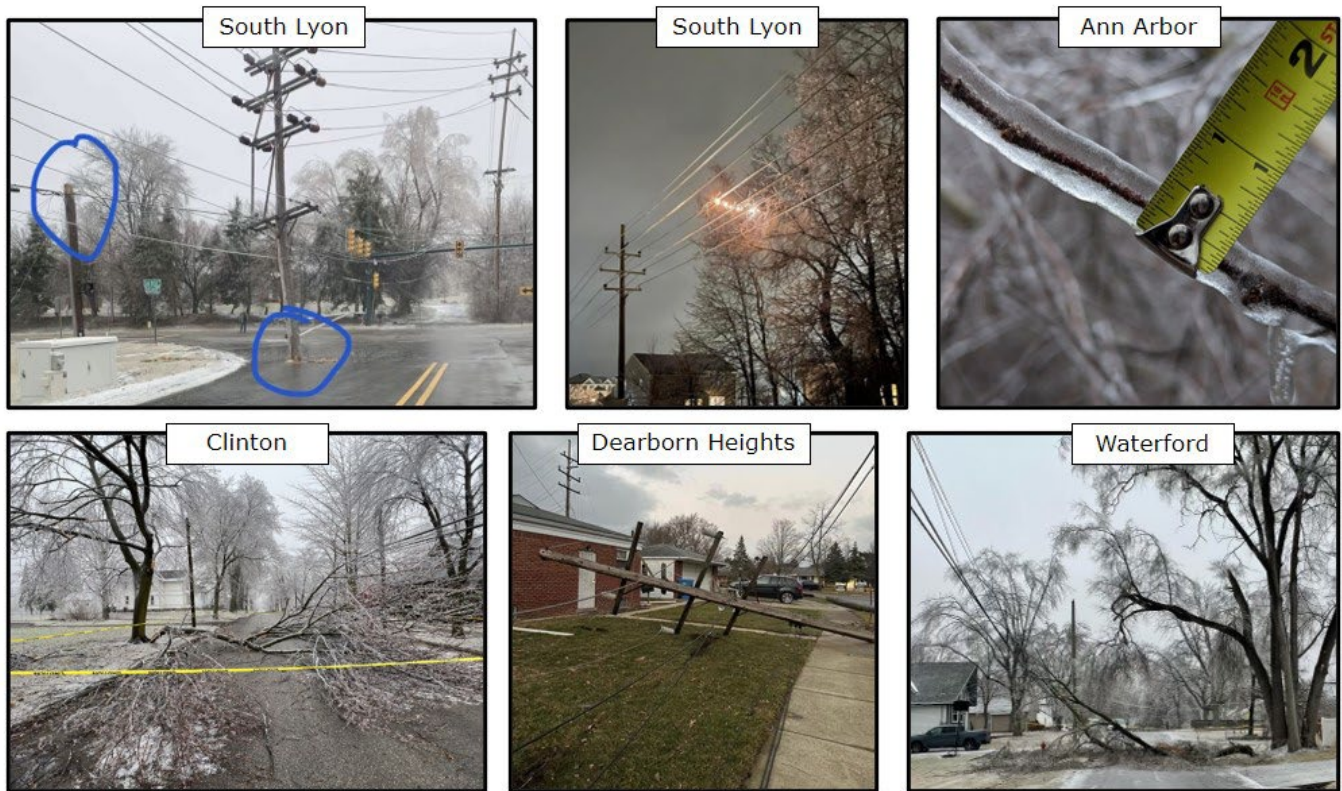
7 **Q19. Can you provide more detail on the February 2023 Ice Storm?**

8 A19. On February 22nd, 2023, an ice storm struck Michigan, causing widespread power
9 outages and hazardous conditions. The freezing rain and ice that hit Michigan
10 downed trees and limbs, power lines, and cut power to about 700,000 homes and
11 businesses, closed schools and offices, and delayed air travel. This was the most
12 damaging ice storm in the Company's history, leaving 675,000 DTE customers
13 without power, some for extended periods of time. The ice was almost ¾" thick in
14 many areas and the weight of the ice severely damaged trees, wires, equipment, and
15 poles. The ice storm also produced heavy wind gusts. The ice and wind caused
16 more than 14,000 reported downed wires across our service territory. Downed trees
17 (roads/streets were closed) and hazardous road conditions presented restoration
18 challenges for our crews.

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1

Figure 1 February 22, 2023 Storm Damage



2

3 **Q20. Can you provide more details on the August 2023 storm that included a**
4 **historic six tornadoes in the DTEE service territory?**

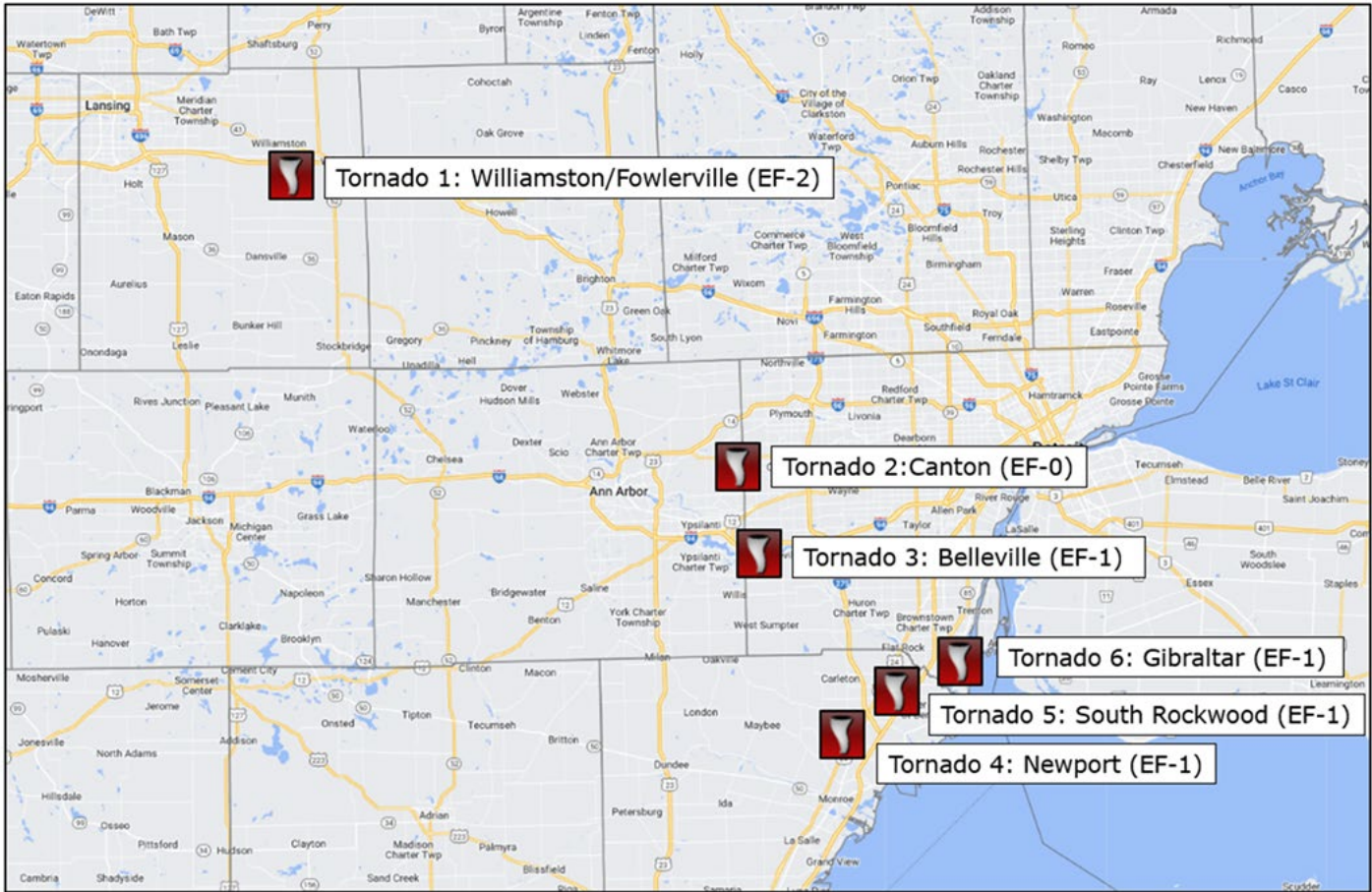
5 A20. On August 23rd, 2023, seven tornadoes touched down in Michigan during late-night
6 thunderstorms that rapidly swept across the lower half of the state. This storm set a
7 Michigan record for the most single-day number of tornadoes in August. Six of
8 these tornadoes touched down in southeast Michigan and in the Company's service
9 territory, resulting in over 390,000 customers without power, some for extended
10 periods of time. The tornadoes uprooted large trees causing extensive damage to
11 pole and wires in several areas across our service territory. This weather event
12 included over 4,600 reported wire downs.

13

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1

Figure 2 August 23, 2023 Storm Tornadoes



2

Line
No.

1

Figure 3

August 23, 2023 Storm Damage



2

Line
No.

1

Figure 4 August 23, 2023 Storm Damage



2

3 **Emergent Replacement – Non-Storm**

4 **Q21. Generally, what is included in Emergent Replacement – Non-Storm?**

5 A21. This category includes capital replacements required to return the overhead and
6 underground distribution systems, and subtransmission electrical system to restore
7 power and/or return to normal operating configuration during non-storm
8 conditions. Non-storm conditions are defined as fewer than 760 customer outage
9 events for the entire system. It includes overhead & underground distribution and
10 the subtransmission system during non-storm conditions, but does not include
11 planned strategic replacements. The “non-storm” description does not imply that
12 these events are not caused by storms, high winds, or other weather-related events.
13 It simply means that there were not enough customer outages for the “storm”

Line
No.

1 threshold to be declared within a twenty-four-hour timeframe. Severe weather
2 damage degrades the electrical system and subsequently results in emergent failures
3 that would then be considered non-storm emergent. This category also includes
4 equipment that fails for other reasons, not related to weather. Not all equipment
5 failures lead to outages. However, failed and damaged equipment are considered
6 emergent and the need to replace this equipment is reasonable and prudent, because
7 it poses risk of power outages and hazards. Examples of this type of work include
8 the replacement of a failed system cable or a broken insulator that has caused a
9 floating line which could break and create an outage or wire down. In addition to
10 trees, some of the non-storm causes for equipment failure include age, overloading,
11 electrical or mechanical issues, vehicles striking poles, or animal interference.
12 Table 1 provides the four high-level non-storm categories, brief descriptions, and
13 examples.

14

Line
No.1
2**Table 1. Emergent – Non-Storm Description**

Category	Description	Example
Non-Storm Emergent	Emergency replacements of equipment during period outside of a declared storm, when customers experience issues with their power supply under both outage and non-outage conditions, but when number of outages is below the Storm threshold	7/7/2022 Dearborn Heights - Garbage truck hopper contacted a communications line and ripped down 5 spans of primary wire and also broke 4 poles and cross arms - Crew cleared the hazards, restored most customers, replaced wires and poles, and then restored remaining customers
Non-Storm Reactive	Replacements of equipment that does not need immediate action and can be scheduled. This includes replacement of failed devices that can be performed during follow-up work that is required to finalize the replacements of assets after initial work is completed to restore customer power and address immediate safety concerns	4/13/2022, Detroit - Broken pole reported due to vehicle accident; crew temporarily fixed pole to remove hazard - Pole was replaced on 5/14/2022; this follow-up work was classified as “Non-Storm Reactive”
Non-Storm Corrective	Replacements of equipment that are required to restore system to original configuration and involve coordination from the System Operations Center (SOC)	1/23/2022, Southfield - Failed underground cable caused an outage that a crew restored, but left system in abnormal condition - Planned outage took place 1/27/2022 and 1/28/2022 to replace the damaged cable; this work was categorized as “Non-Storm Corrective”
Non-Storm Environmental	The disposal of environmentally hazardous materials from the Company’s retirement units/assets that are replaced outside of a declared Storm	3/13/2022, Detroit - Car hit pad mounted transformer, damaging it and causing an oil leak - Crew removed transformer and replaced it - Environmental crew cleaned up oil

3

4 **Q22. What is the Non-Storm forecast for 2023 through 2025?**

5 A22. At the time the 2023 non-storm actual expenditures were estimated for use in the
6 instant case, prior to the end of 2023, the Company forecasted expenditures to be
7 \$207 million (Exhibit A-12 Schedule B5.4, page 1, line 4, column (c)). This
8 forecast is the same as the 5-year historic inflation adjusted average of \$207 million
9 for the time-period 2018 through 2022, Exhibit A-12 Schedule B5.4, page 3, line
10 12, column g. The drivers behind increase non-storm emergent expenditures were
11 discussed in detail in Case No. U-21297 T5 2745-2750. This included supply chain

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1 disruptions, inflation, increasing frequency and severity of weather, greater
2 emphasis on replacing aged and outdated equipment rather than repair, a shift to
3 higher specification materials and components (e.g., fiberglass crossarms rather
4 than wooden), an increase in significant events that require more field crew
5 resources to remediate, a storm preparation strategy to call in crews earlier in
6 anticipation of storm events, and an increase use of contract and out-of-state field
7 crews to be able to more quickly respond to storm events and eliminate follow-up
8 work backlogs immediately after storms. Non-storm emergent expenditures for
9 2024 and 2025 are forecasted at \$220 million and \$227 million (Exhibit A-12
10 Schedule B5.4, page 2, line 4, columns f and g) based on a 5-year inflation adjusted
11 historic average of the period 2018-2022.

12

13 **Q23. Why is the Company forecasting 2024 and 2025 non-storm expenditures using**
14 **a 5-year inflation adjusted historic average?**

15 A23. The Company is using a 5-year inflation adjusted historic average to forecast 2024
16 and 2025 because this method is consistent with Commission orders in previous
17 Case Nos. U-20162, U-20561, U-20836, and most recently, Case No. U-21297
18 dated December 1, 2023. The Company agrees with the Commission that this
19 method is appropriate to account for year-to-year weather variations.

20

21 **Q24. Would it be reasonable or prudent to defer Emergent Replacement – Storm &**
22 **Non-Storm?**

23 A24. No. This work is reasonable and prudent because it addresses system hazards,
24 including customers without power or having partial power. Deferring this work
25 would leave customers without power, reduces grid resiliency, poses system risk of

Line
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1 additional equipment damage resulting in further customer outages, and leaves
2 critical equipment in abnormal conditions. A learning from prior storms was that
3 faster response to address abnormal circuits and equipment as much as reasonably
4 possible before the next weather pattern impacts our service territory mitigates risk
5 for larger customer outages.

6

7 **Emergent Replacement - Substation Reactive**

8 **Q25. Generally, what does Emergent Replacement – Substation Reactive include?**

9 A25. This category includes investments required to perform emergency replacements
10 for substation equipment. The Company makes these investments to replace
11 broken equipment that either led to customer outages, created risk of customer
12 outages, or impacted the operability of the electrical system. Table 2 provides the
13 high-level substation reactive categories, a brief description, and an example.

14 **Table 2. Emergent – Substation Reactive Description**

Category	Description	Example
Substation Reactive- Major Equipment	Replacement of the Company's substation equipment classified as major equipment	August 2022, Twelve Mile Substation - Fire led to catastrophic failure and complete loss of substation - Company deployed portable equipment including a substation and multiple generators
Substation Reactive – Minor Equipment	Replacement of the Company's substation equipment classified as minor equipment	April 2022 UNVIL Substation 40kV insulator broke free - Replaced three 40kV insulators
Substation Reactive – Transformers and Regulators	Replacement of substation transformers and regulators	October 2022, Middlebelt Transformer 2 40-year old transformer failed internally causing outages - Load switched to another transformer for two days until change of transformer complete
Substation Reactive – Non-Electrical Equipment	Replacement of substation retirement units/assets not directly related to generation or transmission of electricity	- Control house HVAC heating to remove condensation which can erode equipment - Fence/gate repairs which are mandated by NERC

Line
No.

1 **Q26. What is the Substation Reactive investment forecast for 2023 through 2025?**

2 A26. At the time the 2023 expenditures used for the instant case were estimated, prior to
3 the end of 2023, the Company forecasted expenditures to be \$42 million (Exhibit
4 A-12 Schedule B5.4, page 2, line 5, column (e)). This forecast is lower than the 5-
5 year historic inflation adjusted average of \$46 million for the time-period 2018
6 through 2022 (Exhibit A-12 Schedule B5.4, page 3, line 19, column (g)). Substation
7 Reactive expenditures for 2024 and 2025 are forecasted at \$49 million and \$51
8 million (Exhibit A-12 Schedule B5.4, page 2, line 5, columns (f) and (g)),
9 respectively, based on a 5-year inflation adjusted historic average of the period
10 2018-2022.

11

12 **Q27. Why are non-electrical substation equipment failures classified under**
13 **substation reactive expenditures?**

14 A27. They are classified this way because the assets and equipment are critical for safety,
15 reliability, and security of the distribution grid. For example, substation fencing
16 prevents the public from entering energized high voltage areas, protects critical
17 equipment, and is part of the grid security plan. When fencing and other physical
18 security type devices fail in an emergent manner, they need to be replaced quickly
19 to ensure public safety and protect the security of the grid. Other equipment like
20 HVAC systems control temperature and condensation in the substation. If this
21 equipment fails, it must be immediately replaced to ensure that the substation
22 operates as designed. Another example of non-electrical substation equipment is
23 substation building infrastructure that houses equipment that fails and must be
24 replaced (roof, doors, sidewalks). These activities are truly reactive in nature and

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1 require the Company to take immediate, prudent action to protect the safety,
2 reliability, and security of the electrical system.

3

4 **Q28. Would it be reasonable or prudent to defer Emergent Replacement –**
5 **Substation Reactive?**

6 A28. No. This work is to replace critical electrical grid equipment that has failed.
7 Substation equipment tends to be less impacted by storms and other weather events,
8 however, when substation equipment fails, in many cases it leaves thousands of
9 customers without power for what can be extended periods of time. The failed
10 equipment significantly reduces distribution capacity and redundancy that is
11 necessary to serve customers in the event of additional system failures and
12 increased seasonal loads. Both these conditions increase risk of additional
13 customer outages. Substation capacity and redundancy is critical and required
14 because these types of failures generally result in repairs that are very lengthy in
15 time (weeks or months) which could result in extended customer outages.

16

17 **Q29. Can you provide additional details regarding Emergent Capital categories for**
18 **all storm, non-storm, and substation reactive expenditures?**

19 A29. Yes. Categories of storm, non-storm, and substation reactive, along with
20 descriptions and examples, are provided in Tables 1-3. Expenditures in Storm and
21 Non-Storm Emergent are incurred in support of the field activities under eight work
22 type categories: Emergency Job, Critical Infrastructure, Customer, Hazards,
23 Multiple Customer Outage, Police/Fire, Public Safety Concern, Single Customer
24 Outage, and Single Customer Problem. Table 3 provides examples for each
25 category.

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1

Table 3. Storm and Non-Storm Work Category

Category	Description
Emergency Job	Non-outage events of the highest priority. These events are restricted to situations where the health and safety of a person are at imminent risk such as a person contacting the Company's electrical equipment, being trapped in a vehicle, building, or elevator due to power failure, downed wires, broken poles, etc.
Critical Infrastructure Customer	Outages affecting hospitals, schools, water and wastewater systems, or other critical infrastructure
Hazards	Non-outage events reported by customers to alert the Company of a potentially hazardous situation due to a sparking wire, broken pole, pole-top fire, and/or a tree or branch resting on a wire
Multiple Customer Outages	Outage events affecting more than one customer on a circuit. Events are created by the Outage Management System (OMS) prediction engine, which uses customer calls, AMI meter data, and the Company's network model to determine the size and extent of an outage. These outages can be caused by weather, trees, animals, public interference (e.g. vehicle accidents), and equipment failures and can involve concerted restoration efforts from overhead, underground, and substation personnel to restore power
Police/Fire	Non-outage events reported by a police or fire department. These events are created when police or fire personnel use their unique PIN number through one of the Company's reporting channels to report an event such as downed power line on a structure or a fire
Public Safety Concern	Non-outage events reported by customers where a primary or secondary wire is believed to have fallen and may pose a safety risk
Single Customer Outage	Outage events that affect a single customer through the same inputs as a multiple customer outage
Single Customer Problem	Non-outage events affecting a single customer that are not outages but can include power quality issues, such as low voltage or flickering lights, or downed service drops where a customer still has power

2

3 **Q30. Has the Company begun to track and report Substation Reactive imminent**
4 **failure work in accordance with the Order in Case No. U-20836 on November**
5 **18, 2022?**

6 A30. Yes. The Company modified its accounting system to begin to track these
7 expenditures and retrained its workforce to be able to separate expenditures related
8 to imminent failures.

9

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1 The Company first began collecting Substation Reactive expenditures associated
2 with imminent failures in January 2023. Imminent Failure Substation Reactive
3 categories are shown in Table 4.

4 **Table 4. Substation Reactive – Imminent Failure Detail²**

Substation Reactive	2023 (\$ thousands)
Imminent Failure – Major Equipment	\$15.9
Imminent Failure – Minor Equipment	\$587.7
Imminent Failure – Minor System/Circuits	\$605.1
Imminent Failure – Transformers/Regulators	\$10.0
Failures – Major Equipment	\$11,075.9
Failures – Minor Equipment	\$13,321.9
Failures – Minor System/Circuits	\$17.5
Failures – Transformers/Regulators	\$11,158.6
Failures – Non-Electrical	\$4,385.6
Total Substation Reactive	\$41,178.3

5

6 **Part II Customer Connections, Relocations & Other Capital Investments**

7 **Q31. Can you please describe the Company's Customer Connections, Relocations**
8 **& Other Capital Investments?**

9 A31. The customer connections, relocations, and other investments category is broken
10 down into six major subcategories: (1) Customer Connections and New Load; (2)
11 Relocations; (3) Electric System Equipment; (4) Normal Retirement Unit Change-
12 out (NRUC) and Improvement Blankets; (5) General Plant, Tools & Equipment

² Values in this table are 2023 calendar year actuals (January through December).

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1 and Miscellaneous; and (6) Public Lighting Department Project. These six
2 subcategories are discussed in more detail below.

3

4 **Q32. Why is the Company forecasting 2024 and 2025 Customer Connections,**
5 **Relocations & Other Capital Investments using a 3-year inflation adjusted**
6 **historic average?**

7 A32. DTEE is using a 3-year inflation adjusted historic average to forecast 2024 and
8 2025 for this category of expenditures because it believes this method is consistent
9 with the Commission Order in the Company's previous rate case, Case No. U-
10 21297.

11

12 There are two exceptions in this category of expenditures that do not use a 3-year
13 inflation adjusted average because they are discrete projects for I-375 relocations
14 and Incremental Infrastructure for EV.

15

16 **Q33. What capital expenditures fall into the Customer Connections and New Load**
17 **subcategory?**

18 A33. Connections and New Load expenditures include: (1) Small Load Growth Projects
19 (2) Customer Connections, (3) New Business Projects, and (4) Incremental
20 Infrastructure for EV.

21

22 Small Load Growth Projects and Customer Connections both include projects
23 required to serve new load, perform upgrades necessary to address small loading
24 issues, and connect customers to the electrical system. Activities in these projects
25 may include reconductoring lines, expanding a substation, or transferring load to

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1 provide local capacity. The Company may also install additional overhead and/or
2 underground lines to provide service to small commercial businesses or housing
3 developments. Small Load Growth & Customer Connections projects typically
4 require less than \$500,000 of expenditures to complete, are less complex in nature,
5 and are therefore developed and executed locally by regional distribution service
6 centers. Small Load Growth & Customer Connections projects are often requested
7 by customers and can include a customer contribution in aid of construction (CIAC)
8 component wherein the customer pays an allocated cost of the new service
9 depending on the load requested and service requirements.

10

11 Like Small Load Growth & Customer Connections projects, New Business projects
12 are also required to serve new load, connect customers to the electrical system, or
13 address local loading issues, however, they are larger scale projects. These larger
14 customer-driven projects typically require more than \$500,000 of expenditures and
15 require a more extensively engineered design to connect customers to the electrical
16 system. New Business projects are typically requested by customers and can also
17 carry a CIAC component.

18

19 Incremental Infrastructure for EV (electric vehicles) is incremental capital for
20 construction of EV charging infrastructure and is a subset of the Company's
21 Transportation Electrification Plan (TEP) discussed further in Question 41 of my
22 testimony.

23

Line
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1 **Q34. What capital expenditures fall into the Relocation subcategory?**

2 A34. Relocation projects are requests from customers, cities, municipalities, or other
3 governmental entities, for example, the Michigan Department of Transportation
4 (MDOT). These are requests to relocate existing Company equipment and
5 facilities. These requests are typically related to construction related to the
6 modification of roadways, bridges, water mains, public sanitation, alleys, or other
7 customer activities.

8
9 The Company equipment being relocated could include overhead lines and poles,
10 underground lines and transformers, and substations equipment. With the increases
11 in federal funding levels for investments in replacing and building infrastructure, it
12 is expected that these types of projects will become more frequent.

13
14 These investments enable economic growth, meet customer needs, are required by
15 regulation, or in some cases are constructed at the request or mandate of
16 governmental entities. Like Customer Connections and New Business, some
17 projects in this category can carry a CIAC component.

18

19 **Q35. What is the I-375 Relocations project under Major Infrastructure Relocation**
20 **Project in this instant case?**

21 A35. MDOT has notified DTEE that the Company will need to relocate distribution
22 infrastructure currently located in the I-375 below-grade freeway corridor, which
23 will be replaced with a grade-level boulevard. MDOT construction is expected to
24 begin in 2025, with DTEE work starting in 2023. This project captures the
25 Company's initial support for the MDOT's I-375 Reconnecting Communities

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1 Project. The Company's support for this project is estimated to require an
2 expenditure of \$39 million (Exhibit A-12, Schedule B5.4, page 5 line 37) spanning
3 from 2023-2025, with the majority of the required work being performed in 2024.
4

5 **Q36. What capital expenditures fall into the Electric System Equipment**
6 **subcategory?**

7 A36. The Company maintains an inventory of critical spare equipment to support
8 emergent replacements and planned projects. This allows equipment repairs and
9 replacements to proceed expeditiously, without waiting for parts delivery from
10 vendors. Equipment purchased under this subcategory includes substation
11 transformers, distribution transformers, regulators, and meters. This equipment
12 often has long lead times, which in many cases have been increasing due to global
13 supply chain and raw material issues. To ensure we can provide electrical service
14 when critical equipment fails or to connect new customers, the Company plans and
15 maintains necessary inventory levels of critical electrical system equipment.
16

17 **Q37. What capital expenditures fall into the NRUC and Improvement Blankets**
18 **subcategory?**

19 A37. The expenditures that fall into this subcategory include: (1) System Improvements,
20 (2) Normal Retirement Unit Change-Out (NRUC), and (3) Operational
21 Technologies.

22 1. System Improvement projects are focused on reducing the frequency and
23 duration of customer outages. Unlike larger scale, longer time frame
24 projects like conversions or subtransmission projects, they are smaller scope
25 projects managed by regional operations to immediately address localized

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1 customer issues and complaints. These projects do not exceed \$350,000
2 and do not require extended planning and design.

3 2. Normal Retirement Unit Change-Out (NRUC) consists of projects to
4 perform scheduled work that replace assets determined by equipment
5 engineers to be at end-of-life.

6 3. Operational Technologies consists of the infrastructure and associated
7 applications that support the AMI platform and data. This also covers
8 annual work in testing new meter types, designing and installing
9 configurations, replacing communications equipment, and testing changes
10 for new equipment.

11

12 **Q38. Has the Company analyzed the customer connections, relocations & other**
13 **program and re-assigned program investment areas that do not fully align**
14 **with the purpose of this category?**

15 A38. Yes. The Company removed Animal Mitigation and Batteries and Charges from
16 Customer Connections, Relocations & Other to strategic capital. The Company will
17 continue to review its project categorization and adjust in the future to help ensure
18 alignment of investment categories.

19

20 **Q39. What capital expenditures fall into the General Plant, Tools & Equipment,**
21 **and Miscellaneous subcategory?**

22 A39. General Plant, Tools & Equipment, and Miscellaneous includes new tools as well
23 as beyond useful life replacement tools required for field workers to perform their
24 tasks. It also includes engineering test equipment and substation physical security.

Line
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1 These expenditures ensure that Company workers have the necessary tools and
2 equipment to conduct and construct field work. Examples of items include meters,
3 phase sets, and infrared cameras. It also includes DC hi-potential testers (Hipoters)
4 that are used to test insulation on cable, breakers, transformers, etc.
5

6 **Q40. What was the Public Lighting Department Project?**

7 A40. The Public Lighting Department (PLD) project converted former PLD customers
8 to the Company's distribution system. This project included extending the
9 Company's overhead and underground system by performing activities like
10 transformer replacements and line extensions. This project was completed with
11 \$1.9 million of investment in 2023 (Exhibit A-12, Schedule B5.4, page 1, line 14,
12 column (c)) with the removal of three breakers from Waterman substation and final
13 connection of the Detroit Institute of Art (DIA).
14

15 **Q41. What is the Incremental Infrastructure for Electric Vehicle (EV) capital**
16 **investment in Exhibit A-12 Schedule B5.4 on page 4, line 29 within Customer**
17 **Connections?**

18 A41. In Case No. U-20836, the MPSC requested DTE Electric to "prepare and submit in
19 its next rate case, a full scale, well-developed, permanent Charging Forward
20 proposal that includes a BCA [benefit cost analysis]."
21

22 In response, Company Witness Bennett and her team has developed a
23 comprehensive Transportation Electrification Plan, with the goal to power and
24 enable a cleaner energy future for its customers through transportation
25 electrification.

Line
No.

1 Incremental Infrastructure for EV consists of capital investments of \$4.7 million in
2 2024 and \$11.4 million in 2025 needed to build out EV charging infrastructure,
3 which is a subset of the DTEE 2023 Transportation Electrification Plan. This capital
4 investment is supported by Company Witness Bennett's testimony in Section 2 The
5 Company's Proposal for a Transportation Electrification Plan and called out in
6 Answer 71.

7

8 **Q42. What work is the Company performing to comply with the Commission's**
9 **Order No. U-21297 regarding line extensions?**

10 A42. The Company has reviewed Section 6 of the Rate Book with respect to customer
11 Contribution in Aid of Construction (CIAC) costs and updated them in Table 5
12 below. These costs represent current cost per foot or cost per kVA developed using
13 compatible unit estimates for associated labor and material costs. Refundable costs
14 capture the full cost of construction and non-refundable costs represent cost
15 differentials between overhead and underground construction.

16

Line
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1

Table 5. Line Extension Cost Updates

<u>Section of Rate</u> <u>Book</u>	<u>Page</u>	<u>Element to be updated</u>	<u>Current</u> <u>Rate</u>	<u>Updated</u> <u>Rate</u>
C6.2(1b)	C-28	Refundable construction advance of \$6.50 per foot	\$6.5	\$16.91
C6.3(A)(14)	C-33	\$1.00 per trench foot added for winter construction	\$1.0	\$1.0
C6.3(B)(2)	C-34	multiplying the sum of the lot front footage for all lots in the subdivision by \$3.00	\$3.00	\$18.30
C6.3(B)(6)(a)	C-35	\$3.00 per lot front foot for the total front footage	\$3.00	\$18.30
C6.3(C)(2)(a)	C-36	lot front footage for all lots in the park by \$3.00	\$3.00	\$18.30
C6.3(C)(2)(c)	C-36	Transformers - \$7.50 per kVA, for the total nameplate kVA installed.	\$7.50	\$18.47
C6.3(D)(2)(a)	C-37	total length of trench feet required for distribution facilities by \$4.30 plus \$7.50 per kVA (nameplate) of transformer capacity to be installed.	\$4.30 per trench ft + \$7.5 per kVA	\$17.84 per trench ft + \$18.47 per kVA
C6.3(E)(2)(a)	C-38	total length in feet multiplied by \$4.30	\$4.30	\$17.84
C6.3(E)(2)(b)	C-38	Transformers will be charged on an installed basis of \$7.50 per kVA	\$7.50	\$18.47
C6.4(A)	C-38	\$300 for trench lengths up to 200 feet	\$300	\$730
C6.4(A)	C-38	\$3.90 per foot for each additional foot added	\$3.90	\$9.48
C6.4(B)	C-39	\$3.90 per foot for each additional foot added	\$3.90	\$9.48
C6.4(C)	C-39	trench length in feet multiplied by \$4.30	\$4.30	\$17.84
C6.4(C)(2)(b)	C-39.01	multiplying the horizontal length of the service lateral in feet by \$10.00.	No Change	
C6.4(C)(3)(c)(a)	C-39.02	\$4.30 per trench foot	\$4.30	\$17.84
C6.4(C)(3)(c)(c)	C-39.02	\$15 per kVA for all dry type transformers.	No Change	

Line
No.

C6.4(D)(1)(c)	C-40	multiplying the horizontal length of the service lateral in feet by \$10.00	No Change	
C6.5(A)(1)(a)	C-42	0.48 per kVA of installed transformer capacity for the first 10kVA	No Change	
C6.5(A)(1)(b)	C-42	0.12 per kVA of installed transformer capacity for excess of 10kVA	No Change	
C6.6(H)	C-45	Recalculate if more than \$1 for customer, or more than \$2 for someone no longer customer.	No Change	

1

2 **Part III Portable Generators**

3 **Q43. What are the Portable Generators in Exhibit A-12, Schedule B5.4, page 13,**
4 **line 28 under the Infrastructure Resilience and Hardening pillar?**

5 A43. The \$4.5 million for Portable Generators in 2024 is to purchase generators that the
6 Company will deploy to customers to provide temporary electricity during storms.
7 The company will prioritize generators to customers based on the estimated
8 duration of storm outage, customer medical needs, and other factors.

9

10 Deployment of generators will not be done by lineworkers and therefore will not
11 impact restoration time for our customers. Most of the generators allow customers
12 to use devices that draw less than 2,000 watts. This typically includes items like
13 refrigerators, freezers, personal medical devices, and sump pumps.

14

Line
No.

1 **Part IV Miss Dig**

2 **Q44. What did the Commission order regarding the tracking of infrastructure**
3 **strikes related to Miss Dig in Case No. U-21297?**

4 A44. The MPSC Staff recommended, and the Commission Ordered the following
5 concerning Miss Dig in the Order No. U-21297, page 376, dated December 1, 2023:
6 “Pertaining to the Miss Dig program, DTE Electric Company shall commence
7 tracking and keeping records of expenditures incurred from damages caused by the
8 company to its own facilities; work with the Commission Staff to share damage
9 reporting data including the billing amounts for damages when a third-party causes
10 damages and expenditures for damages, and for sharing billing amounts when the
11 company causes damages; include a breakdown of damage prevention expenditures
12 in future general rate cases under Federal Energy Regulatory Commission account
13 580 including, but not limited to, internal locating and contract locating in future
14 general rate cases; and improve the company’s damage reporting quality by
15 continuing to meet with the Commission Staff regarding damage report data and
16 committing the time and resources to submitting data into the format that aligns
17 with the Commission’s processes.”

18

19 **Q45. How is the Company responding to these Miss Dig expenditures tracking and**
20 **reporting requirements that were Ordered in Case No. U-21297?**

21 A45. The Company is actively working on plans to comply with the recommendations
22 and reporting requirements. The Company met with MPSC Staff during Case No.
23 U-21297 and continues to meet with Staff on a bi-monthly basis.

24

Line
No.

1 **Q46. What progress has the Company made since the Case No. U-21297 Order?**

2 A46. The Company updated the formatting and data in the Miss Dig damage report. This
3 report includes information on damage claims by responsible party, the amount of
4 damage/expenditures, and causes of the damage. This information is shared
5 monthly and reviewed during meetings with MPSC Staff and enables open dialogue
6 on damage prevention. The report includes first party damages caused by the
7 Company to its own facilities. The Company will continue monthly meetings with
8 MPSC Staff to further make additional improvements and comply with the order.

9

10 **Q47. Does this complete your direct testimony?**

11 A47. Yes, it does.

12

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

BRIAN L. HILL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF BRIAN L. HILL

Line
No.

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

3 A1. My name is Brian L. Hill (he, him, his), and my business address is One Energy
4 Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
5 (DTE Electric or Company).

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of this testimony is to rebut certain positions of Attorney General (AG)
14 Witness Coppola, Association of Businesses Advocating Tariff Equity (ABATE)
15 Witness York, Michigan Public Service Commission (MPSC or Commission) Staff
16 (Staff) Witness Duell, and Michigan Environmental Council (MEC), Natural
17 Resource Defense Council (NRDC), Citizens Utility Board of Michigan (CUB)
18 (collectively “CUB-MN”) Witness Denzler, and The City of Ann Arbor (AA)
19 Witness Stults. The absence of a discussion of other matters in my rebuttal
20 testimony should not be taken as an indication of agreement with other aspects of
21 any intervenor’s testimony.

Line
No.

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

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-52	QQ1	U.S. Department of Defense Inflation and Escalation Best Practices for Cost Analysis
A-52	QQ2	Discovery Response: U-21534 AGDE-3.93a
A-52	QQ3	Discovery Response: U-21534 AGDE-3.95b-01 Emergent Savings 2024-2025

10 **Q5. Were these exhibits prepared by you or under your direction?**

11 A5. Yes, they were.

13 **Q6. How is your testimony organized?**

14 A6. There are sixteen specific points I will rebut in my testimony, as listed below. A
15 discussion of why the intervenor's recommendations should not be accepted by the
16 Commission follows.

Rebuttal Contents

19	Purpose of Testimony	1
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1 **Capital Emergent Replacements (Exhibit A-12, Schedule B5.4, page 3)**

2 Rebuttal Issue 1: AG Witness Coppola's position that it is inappropriate to apply
3 inflation adjustments to historic years and that nominal historical values should be
4 used for forecasting.

5 **Q7. What is AG Witness Coppola's recommendation regarding Capital Emergent**
6 **Replacement programs?**

7 A7. On page 20, lines 12-13, AG Witness Coppola recommends a disallowance of
8 \$24,526,000 for 2024, and \$28,557,000 for 2025 for Capital Emergent
9 Replacements.

10

11 **Q8. Why does AG Witness Coppola make these recommendations?**

12 A8. AG Witness Coppola uses three points to support his recommendation for
13 disallowance:

14

15 1). "Although I agree with using a five-year normalization approach to forecast
16 capital expenditures for future years, it should be done using actual capital
17 expenditures from prior years, not by recasting numbers with additional assumed
18 costs that were not incurred based on prior year inflation adjustments. If any
19 inflation was experienced in those prior years, it is reflected in the actual amounts.
20 It is simply an unsupported fabrication to inflate historical costs to arrive at an
21 adjusted historical base and to then further inflate those costs for future years with
22 projected inflation factors." (page 18, lines 3-9)

23

24 2). "I will also point out that the future inflation rates used by the Company to
25 calculate forecasted Emergent Replacements capital expenditures for 2023, 2024,

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1 and 2025 are blended inflation rates consisting of both the CPI and the Company's
2 internal forecasted wage increases. As discussed in more detail in the O&M
3 Expense - Inflation Adjustment section of my testimony, the Commission has
4 previously rejected the use of blended inflation rates." (page 18, lines 9-14)

5

6 3). "I will also point out that contrary to the directives by the Commission in Case
7 Nos. U-20561 and U-20836, the Company did not provide an analysis in this rate
8 case of the offsetting effects of significant distribution capital investments on
9 inflationary pressures on Emergent Replacements." (page 18, lines 15-18)

10

11 **Q9. Do you agree with AG Witness Coppola's recommendation of not applying**
12 **inflation to historic expenditures?**

13 A9. No. While AG Witness Coppola agrees with the use of the five-year normalization
14 to forecast capital expenditures for future years (page 18, line 3-4 of his direct
15 testimony), the Company does not agree with his recommendation of not using
16 historical inflation adjustments.

17

18 The use of inflation is reasonable and appropriate to adjust past expenditures using
19 CPI (Consumer Price Index) to make them comparable with current dollars when
20 they are being used as the basis for future projections starting in a specific year (in
21 this case, that year is 2022, the historic test year).

22

23 It is not an "unsupported fabrication" to apply inflation to historic years. Rather,
24 the Company is appropriately recognizing the time value of money and bringing
25 historic expenditures to a common denomination (baseline), which in the instant

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1 case is 2022 dollars. This baseline is then used to forecast future capital emergent
2 replacement expenditures.

3

4 Actual historic capital expenditures only include inflation incurred in the years
5 leading up to and during that year. Using 2019 historic capital expenditures as an
6 example, they include inflation incurred from prior years and in 2019. However,
7 for calculating a baseline from which to forecast future emergent replacements it is
8 necessary to adjust the 2019 historic capital expenditures with inflation seen from
9 2019 through 2022. Omitting this adjustment on actual historic emergent
10 replacement expenditures would understate the amount of capital required to do the
11 same scope of work in future years.

12

13 **Q10. Has the Commission remarked on this using historical inflation calculations**
14 **in prior cases?**

15 A10. Yes. In Case No. U-20836 the Commission confirmed that a historic adjustment
16 was reasonable, stating on page 63 of the order dated November 18, 2022: “The
17 Commission agrees with, and finds appropriate, the ALJ’s recommendation for the
18 continued use of the five-year average in determining this category of expenditures,
19 *along with the inflationary adjustment to historical data [emphasis added]*,
20 considering this record and increased climate variability over recent years.”

21

22 Additionally, in Case No. U-21297 the Commission confirmed in its order that a
23 historic inflation adjustment was reasonable, stating “The Commission rejects the
24 Attorney General’s inflationary adjustment and finds that DTE Electric has
25 computed the historic average in a manner consistent with Case Nos. U-20836 and

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1 U-20561. *See*, November 18 order, p. 63; May 8 order, p. 86. Regarding the
2 inflationary adjustment, the Commission further acknowledges this case was filed
3 only two months after the issuance of the November 18 order. However, the
4 directives from that order still stand and the Commission anticipates an analysis of
5 the offsetting effects of significant distribution capital investments on inflationary
6 pressures for this cost category in the company's next filed rate case." (U-21297
7 page 76)

8

9 **Q11. Has the Company researched any third-party documentation supporting its**
10 **methodology to adjust historic years with inflation to derive a baseline to use**
11 **for forecasting future expenditures?**

12 A11. Yes. The Company's practice of adjusting historic years to derive a baseline
13 expressed in current dollar values is consistent with the constant-year method
14 (inflation normalized values) discussed within the December 2021 U.S.
15 Department of Defense Inflation and Escalation Best Practices for Cost Analysis
16 (Exhibit A-52, Schedule QQ1).

17

18 In summary, the U.S. Department of Defense best practices state that:

- 19 • Then-year (historical nominal price) is appropriate for understanding actual
20 historical expenditures incurred;
- 21 • Constant-year (inflation adjusted price) is appropriate for estimating,
22 comparing, or reporting;
- 23 • Constant price (values that exclude inflation and price escalation) is only to be
24 used internally as a modeling technique or to understand historical trends and
25 not to be presented publicly.

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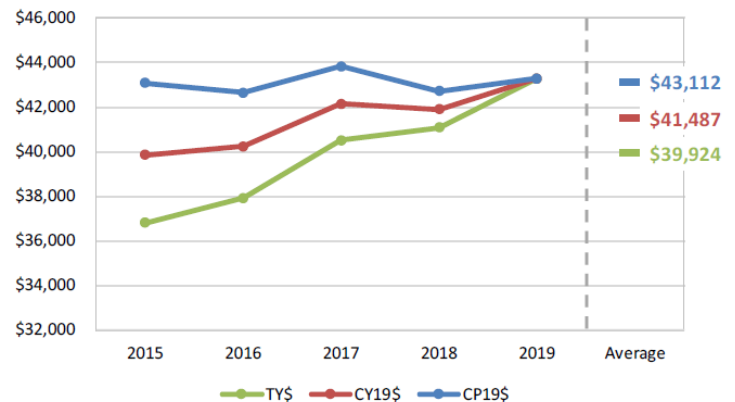
1 **Q12. Does the 2021 United States Department of Defense Inflation and Escalation**
2 **Best Practices for Cost Analysis Handbook (Exhibit A-52, Schedule QQ1)**
3 **provide a visual example?**

4 A12. Yes, page 44 shows an example in Figure 5-4. Calculating average cost factors from
5 historical costs (Table 1).
6

7 **Table 1 DOD – Best Practices Handbook Page 44, Figure 5-4**

Figure 5-4. Calculating average cost factors from historical costs.

Fiscal Year	TY\$	Escalation Index (BY19)	Inflation Index (BY19)	CP19\$ (=TY/esc)	CY19\$ (=TY/inf)
2015	\$ 36,819	0.8548	0.9238	\$ 43,073	\$ 39,854
2016	\$ 37,917	0.8890	0.9423	\$ 42,651	\$ 40,238
2017	\$ 40,518	0.9246	0.9612	\$ 43,824	\$ 42,155
2018	\$ 41,079	0.9615	0.9804	\$ 42,722	\$ 41,901
2019	\$ 43,289	1.0000	1.0000	\$ 43,289	\$ 43,289
Average	\$ 39,924			\$ 43,112	\$ 41,487



8 Page 44 also states, “Out of the three options for averages calculated above, *you*
9 *immediately rule out using the average calculated in TY\$ because it has lost any*
10 *connection to a particular point in time (i.e., the average is a mixture of*
11 *transaction years, and there is no unifying base year for TY\$).*” [emphasis added]
12

13 Please note that the TY\$ approach of using nominal historical dollar values, which
14 is consistent with the approach AG Witness Coppola recommends, is the approach
15 that the U.S. Department of Defense concludes should be immediately ruled out
16 because it does not have a unifying base year (what the Company refers to as a
17 baseline).

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2

The Company's approach of using inflation adjusted historic years to determine a baseline from which to forecast future years is consistent with the constant-year (inflation adjusted) methodology which is recommended by the U.S. Department of Defense for estimating, comparing, and reporting.

6

7

Q13. Should the Commission accept AG Witness Coppola's recommended disallowances due to rejecting historic inflation adjustments?

8

9

A13. No. As discussed above, the Commission has approved this methodology in prior cases, and it remains a reasonable and prudent methodology to forecast future expenditures. As explained in the 2021 United States Department of Defense Inflation and Escalation Best Practices for Cost Analysis Handbook (Exhibit A-52, Schedule QQ1), using nominal historic dollar values (transaction-year dollars) as Witness Coppola suggests is inappropriate because they only represent the value of dollars in the year they were spent and do not reflect changes in prices experienced since.

17

18

The Commission should maintain its position from prior cases and reject AG Witness Coppola's recommendation.

19

20

21

Rebuttal Issue 2: AG Witness Coppola's disagreement with using blended inflation rates for future years.

22

23

Q14. Do you agree with AG Witness Coppola's assertion that it is inappropriate to use blended inflation rates for 2023, 2024, and 2025?

24

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1 A14. No. As discussed in Company Witness Foley's rebuttal testimony (reference the
2 Inflation Rate section starting on page NTF-35-Rebuttal), the Company does not
3 agree with Witness Coppola's recommendation to reject the Company's proposed
4 blended inflation rates.

5

6 Rebuttal Issue 3: AG Witness Coppola's assertion that the Company did not perform
7 an analysis to include significant distribution capital investments savings offsets.

8 **Q15. Did the Company perform an analysis that included savings offsets from**
9 **Strategic Capital Investments?**

10 A15. Yes. In Exhibit A-12, Schedule B5.4, page 1, line 6 shows a reduction in Capital
11 Emergent Replacements of \$20,819,951 for 2024 and \$21,435,815 in 2025.

12

13 Further, I explain on page 8, lines 19-24 of my direct testimony that this reduction
14 is due to savings from both Strategic Capital Investments and the Tree Trim Surge
15 program. I state that the reduction calculation is from the analysis performed in the
16 Company's reliability model (as discussed in Company Witness Kryscynski's
17 testimony), which is included in this instant case as WP AJK U-21534 Reliability
18 Model.xlsx (Exhibit A-43, Schedule HH5). These savings calculations were
19 provided in discovery response U-21534 AGDE-3.95b-01 Emergent Savings 2024-
20 2025.xlsx (Exhibit A-52, Schedule QQ3).

21

22 Rebuttal Issue 4: ABATE Witness York's recommendation to remove 2021 historic
23 Capital Emergent Replacements from its five-year historical average.

24 **Q16. What does ABATE Witness York argue concerning historic averages used to**
25 **forecast Capital Emergent Replacements?**

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1 A16. ABATE Witness York on (pages 29 and 30), recommends the adoption of a non-
2 consecutive four-year historic average (2018-2022, excluding 2021) and a resulting
3 disallowance of \$122.822 million for Capital Emergent Replacements.
4

5 **Q17. Why does ABATE Witness York make these recommendations?**

6 A17. On pages 28, lines 11-20 and page 29, lines 1-2, ABATE Witness York states:
7 “While the five-year average has historically been approved by the Commission, it
8 is inappropriate to rely on a five-year average in this case. Specifically, 2021 data
9 should not be included in the historical average, as it was an abnormal year in terms
10 of storm activity. This unprecedented nature of 2021 is also evident from a review
11 of expenditures on storm-related emergent replacements shown on Exhibit A-12,
12 schedule B5.4, page 3. In 2021, these expenditures more than doubled relative to
13 DTE’s annual expenditures from 2018-2020. In 2022, the number of storm days
14 was lower than DTE projected, and there was only one catastrophic storm, which
15 was also lower than the Company’s internal forecast.”
16

17 **Q18. Does the Company agree with ABATE Witness York’s recommended method**
18 **to calculate the level of Capital Emergent Replacements using a four-year non-**
19 **consecutive historical average, and her resultant proposed disallowance?**

20 A18. No. The Company does not agree with using a four-year non-consecutive average.
21 The use of a five-year historic average appropriately accounts for weather
22 variability when forecasting future expenditures for Capital Emergent
23 Replacements. Specifically selecting the highest storm years and then excluding
24 them undermines the intent of a five-year average to account for year-to-year
25 variability in weather.

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1 The Company acknowledged in Case No. U-21297 that the storms in the Summer
2 of 2021 were historic, but that did not imply that severe weather events will never
3 occur again. In fact, as explained in my direct testimony on pages 9-14, in 2023
4 the Company experienced the worst ice storm in its history along with six summer
5 tornadoes resulting in major damage to the electric grid. In total, the Company
6 experienced seven storms in 2023, with two being CAT-1 and three being CAT-2.
7 A CAT-1 storm is defined as 110,000 customers or more without power in a 24-
8 hour period (5% of total customers affected). A CAT-2 storm is defined as 220,000
9 customers or more without power in a 24-hour period (10% of total customers
10 affected).

11

12 **Q19. Has the Commission ruled whether a five-year average is appropriate?**

13 A19. Yes, the five-year forecast has been approved in prior cases U-20162, U-20561, U-
14 20836, and U-21297.

15

16 In Case No. U-20836, the Commission confirmed that a five-year average was
17 appropriate, stating on page 63 of the order dated November 18, 2022: “The
18 Commission agrees with, and finds appropriate, the ALJ’s recommendation for the
19 continued use of the five-year average in determining this category of expenditures,
20 along with the inflationary adjustment to historical data, considering this record and
21 increased climate variability over recent years.”

22 In Case No. U-21297, the Commission again confirmed the usage of a five-year
23 average, stating on page 76 of the order dated December 1, 2023: “Additionally, in

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1 light of the fact that anomalous weather is becoming the norm, the Commission
2 agrees with the ALJ's decision to incorporate all five years in the average. PFD, p.
3 204. As the company notes, 2023 was another anomalous year."

4

5 **Q20. Should the Commission adopt ABATE Witness York's proposed disallowance**
6 **associated with Capital Emergent Replacements?**

7 A20. No. The Commission should reject ABATE Witness York's recommended
8 disallowance of Capital Emergent Replacements expenditures (based on a four-
9 year average excluding 2021). The use of a five-year historic average is the most
10 reasonable and prudent way to forecast future Capital Emergent Replacement
11 expenditures and has been consistently approved by the Commission. The
12 Commission's November 18, 2022 order in Case No. U-20836, noted on page 63:
13 "The Commission agrees with, and finds appropriate, the ALJ's recommendation
14 for the continued use of the five-year average in determining this category of
15 expenditures, along with the inflationary adjustment to historical data, considering
16 this record and increased climate variability over recent years."

17

18 **Base Capital – Emergent Replacements and Customer Connections, Relocations and**
19 **Other (Exhibit A-12, Schedule B5.4, page 1, lines 1-17)**

20 Rebuttal Issue 5: ABATE Witness York's recommendation to adopt Real Chained
21 GDP Index instead of CPI when calculating inflation.

22 **Q21. What is ABATE Witness York's recommendation regarding calculation of**
23 **future levels of base capital?**

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1 A21. ABATE Witness York on page 29 argues that the Company should use GDP
2 Chained Real Price Index rather than CPI inflation rates to project future
3 expenditures (2023-2025) for all base capital categories.

4

5 **Q22. What arguments does ABATE Witness York make regarding changing from**
6 **utilizing CPI to using Real Chained Index?**

7 A22. On page 13, lines 6-18, ABATE Witness York argues that Real GDP Chained Price
8 Index reflects what people are actually buying, is more responsive to customer
9 substitution, and that CPI is heavily weighted by the cost of medical expenses
10 which are not reflective of utility expenses.

11

12 **Q23. Does the Company agree with ABATE Witness York's recommendation to**
13 **change the Company's inflation forecast methodology from CPI to Real**
14 **Chained GDP Index?**

15 A23. No. CPI is the most widely used measure of inflation and for adjusting dollar values
16 for government entities and businesses in the United States. This topic is also
17 discussed in Company Witness Foley's rebuttal testimony.

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1 **Distribution Plant – Customer Connections, Relocations and Other (Exhibit A-12,**
2 **Schedule B5.4, page 4)**

3 Rebuttal Issue 6: AG Witness Coppola’s recommendation to remove historic
4 inflation adjustments for Electric System Equipment and General Plant, Tools &
5 Equipment and Miscellaneous.

6 **Q24. What is AG Witness Coppola’s recommendation regarding historic inflation**
7 **adjustments for Electric System Equipment and General Plant, Tools &**
8 **Equipment and Miscellaneous?**

9 A24. AG Witness Coppola proposed disallowances for these expenditures are based on
10 the same recommendations discussed above in Emergent Replacements. Simply
11 stated, AG Witness Coppola disagrees with applying inflation to historical years to
12 calculate future expenditures. As a result of not using historical inflation AG
13 Witness Coppola proposes the following reductions:

- 14
- 15 • Electric System Equipment: \$3,153,000 for 2024 and \$3,456,000 for
16 2025 (page 29, lines 13-15)
 - 17 • General Plant, Tools & Equipment and Miscellaneous: \$1,758,000 for
18 2024 and \$1,862,000 for 2025 (page 30, lines 13-16)
- 19

20 **Q25. Why does AG Witness Coppola make this recommendation?**

21 A25. AG Witness Coppola’s testimony on page 21, lines 6-13, states “... the Company
22 applied retroactive historical inflation rates to restate the actual historical number
23 for the three years from 2019 to 2022, before applying the future inflation rates to
24 the adjusted three-year historical average spending. This is the same problem
25 discussed above with Emergent Replacements, where the Company improperly

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1 inflates actual historical capital expenditures to create a larger cost base on which
2 to add future inflation adjustments. Mr. Hill also used this faulty approach to
3 forecast capital expenditures for Relocations, Electric System Equipment, NRUC
4 and Improvements Blankets, and General Plant, Tools & Equipment.”

5

6 **Q26. Do you agree with AG Witness Coppola’s recommendation of not applying**
7 **inflation to historic expenditures?**

8 A26. No. While AG Witness Coppola agrees with the use of the three-year average to
9 forecast capital expenditures for future years (page 21, lines 14-21), the Company
10 disagrees with his recommendation of not using historical inflation adjustments.

11

12 The use of inflation is reasonable and appropriate to adjust past expenditures using
13 CPI (Consumer Price Index) to make them comparable with current dollars when
14 they are being used as the basis for future projections starting in a specific year (in
15 this case, that year is 2022, the historic test year).

16

17 It is not an “unsupported fabrication” to apply inflation to historic years. Rather,
18 the Company is appropriately recognizing the time value of money and bringing
19 historic expenditures to a common denomination (baseline), which in the instant
20 case is 2022 dollars. This baseline is then used to forecast future capital emergent
21 replacement expenditures.

22

23 Historic capital expenditures only include inflation incurred in the years leading up
24 to and during that year. Using 2019 historic capital expenditures as an example, this
25 total includes inflation incurred from prior years and in 2019. However, for

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1 calculating a baseline from which to forecast future emergent replacements it is
2 necessary to adjust the 2019 historic capital expenditures with inflation seen from
3 2019 through 2022. Not performing this adjustment on historic emergent
4 replacement expenditures would understate the amount of capital required to do the
5 same scope of work in future years.

6

7 **Q27. Has the Commission remarked on this using historic inflation adjustments in**
8 **prior cases?**

9 A27. Yes. The Commission has supported the usage of historic inflation adjustments for
10 Capital Emergent Replacements in Case Nos. U-20836 and U-21297 as discussed
11 in Q&A 10 earlier in my rebuttal testimony.

12

13 **Q28. Should the Commission adopt AG Witness Coppola's disallowance due to**
14 **historic inflation adjustments applied to Distribution Plant – Customer**
15 **Connections, Relocations and Other?**

16 A28. No. The Company's application of inflation to prior years is consistent with how it
17 has historically forecasted Capital Emergent Replacements and those forecasts
18 have received Commission approval.

19 Additionally, the Company has presented evidence in Q&As 9-13 in this rebuttal
20 testimony above showing that the Company's methodology of applying historic
21 inflation is consistent with the U.S. Department of Defense best practices.

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1 Rebuttal Issue 7: AG Witness Coppola's recommended disallowances for Customer
2 Connections and New Load due to removing historic inflation calculations and
3 changes to forecasting methodologies.

4 **Q29. What is AG Witness Coppola's recommendation regarding Customer**
5 **Connections and New Load Growth?**

6 A29. There are two separate recommendations AG Witness Coppola makes regarding
7 this category:

9 1) AG Witness Coppola's testimony recommends a disallowance of \$14,453,000
10 for 2024 and an increase of \$3,405,000 for 2025 for Customer Connections and
11 New Load Growth on page 24, lines 13-15.

12

13 2) AG Witness Coppola's testimony recommends an additional disallowance of
14 \$3,734,000 in 2024 and \$10,173,000 in 2025 for Customer Connections and
15 New Load that is associated with Utility Make Ready (UMR) projects
16 supporting electric vehicle adoption on page 26, lines 11-12.

17

18 **Q30. Why does AG Witness Coppola make the first recommendation for**
19 **disallowances for Customer Connections and New Load Growth?**

20 A30. On page 24, lines 3-15 of his direct testimony Witness Coppola calculates these
21 disallowance totals by removing Utility Make Ready (UMR) expenditures, then
22 calculating the 2021-2023 average annual expenditures (without historic inflation
23 adjustments), and applying Michigan housing starts forecasts of -3.8% in 2024 and
24 +10.8% in 2025. He then compares his forecasts to those of the Company and
25 proposes the difference between the two as adjustments to this category.

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1 **Q31. Do you agree with AG Witness Coppola's arguments for disallowances to**
2 **Customer Connections and New Load Growth due to the removal of historic**
3 **inflation adjustments?**

4 A31. No. The reasonableness of using historic inflation adjustments is discussed in
5 Q&As 9-13 in this rebuttal testimony above which shows it is identified as a U.S.
6 Department of Defense best practice for estimating.

7

8 **Q32. Do you agree with AG Witness Coppola's arguments for disallowances due to**
9 **using Michigan housing starts forecasts rather than the historic three-year**
10 **average for future years?**

11 A32. No. The Company would like to emphasize that this category of expenditures
12 includes activities beyond connecting new homes such as customer requested
13 upgrades, accommodating business development, and resolving circuit loading
14 issues which are not directly tied to residential housing starts.

15

16 **Q33. Should the Commission adopt AG Witness Coppola's recommended**
17 **disallowances for 2024 and 2025 Customer Connections and New Load**
18 **Growth due to removal of historic inflation adjustments and Michigan housing**
19 **start forecasts?**

20 A33. No. The application of historic inflation adjustments is appropriate, and this
21 category of expenditures includes work that is independent of new home builds.
22 The Company's methodology of using a three-year inflation adjusted forecast is
23 reasonable and prudent.

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1 Rebuttal Issue 8: AG Witness Coppola's recommended disallowances for Customer
2 Connections and New Load Utility Make Ready (UMR) due to changes to EV
3 forecasts.

4 **Q34. Why does AG Witness Coppola make the second recommendation for**
5 **Customer Connections and New Load disallowances associated with Utility**
6 **Make Ready (UMR) projects?**

7 A34. AG Witness Coppola states on pages 25 and 26:

- 8 • The Company's EV adoption forecast is unrealistic,
9 • Customers are unhappy with electric vehicles,
10 • Auto manufacturers are shifting from EVs to self-charging hybrids in
11 response,
12 • It is more appropriate to forecast 2024 and 2025 using 2023 actual
13 expenditures plus inflation,
14 • A disallowance of \$3,734,000 for 2024 and \$10,173,000 for 2025 are
15 therefore justified.

16

17 **Q35. Do you agree with AG Witness Coppola's arguments for disallowances to**
18 **Utility Make Ready (UMR) projects?**

19 A35. No. The Company supports ensuring the distribution grid is ready for EV adoption,
20 consistent with the shift to EVs that are a critical part of the Michigan MI Healthy
21 Climate Plan. This topic is rebutted in detail by Company Witness Bennett
22 (beginning on page PB-8).

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1 Rebuttal Issue 9: AG Witness Coppola’s recommended disallowance for the I-375
2 Relocation Project (Exhibit A-12, Schedule B5.4, page 7, line 37)

3 **Q36. What is AG Witness Coppola’s recommendation regarding the I-375**
4 **Relocation Project?**

5 A36. He recommends disallowances of \$25,000,000 for 2024 and \$8,000,000 for 2025
6 associated with the I-375 Relocation Project (page 28, lines 14-15). These
7 recommended disallowance amounts reflect the entirety of the Company’s
8 requested capital expenditures for the project.

9

10 **Q37. Why does AG Witness Coppola’s recommend a full disallowance for 2024 and**
11 **2025 expenditures for the I-375 Relocation Project?**

12 A37. AG Witness Coppola states on page 28, lines 8-15, “MDOT is known for
13 establishing initial plans and later delaying projects. Although the Company may
14 have done some design and engineering work in 2023 with the \$5.9 million
15 budgeted, it is unlikely that it will spend the \$25 million forecasted for 2024 or the
16 \$8 million forecasted for 2025. It is premature and imprudent to include those large
17 amounts in rate base in this rate case. The Company would be earning a return and
18 recovering depreciation expense for costs that would likely not be incurred.
19 Therefore, I recommend that the Commission remove the \$25 million for 2024 and
20 the \$8 million for 2025 from the Company’s forecasted capital expenditures.”

21

22 **Q38. Do you agree with AG Witness Coppola’s recommendation for a full**
23 **disallowance for 2024 and 2025 expenditures for the I-375 Relocation Project?**

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1 A38. No. The Company has received a notice to vacate from MDOT and must proceed
2 with work. It is not reasonable to expect that the entirety of the project will be
3 delayed and that no work will be performed by the Company in 2024 or 2025.

4

5 The Company's current forecast, as of this testimony, is that \$8,842,825 will be
6 invested for this project in 2024 and that \$13,802,315 will be invested for this
7 project in 2025 (Table 2).

8

9

Table 2 I-375 Relocation Forecasts

I-375 Relocation	2024	2025
Exhibit A-12, Schedule B5.4	\$25,000,000	\$8,000,000
Current DTEE Forecast	\$8,842,825	\$13,802,315
Difference (Lower) / Higher	(\$16,157,175)	\$5,802,315

10

11 **Q39. Should the Commission accept AG Witness Coppola's recommendation to**
12 **disallow all amounts associated with the I-375 Relocation project in 2024 and**
13 **2025?**

14 A39. No. The Company has received a notice to vacate from MDOT and must proceed
15 with work. It is not reasonable to expect that zero work will be completed on the I-
16 375 Relocation project in 2024 and 2025.

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1 It would be reasonable and prudent to approve the adjusted forecasted amounts
2 provided in Table 2 above, which account for currently known project delays, and
3 would result in a disallowance of \$16,157,175 for 2024 and an increase of
4 \$5,802,315 for 2025.

5

6 **Portable Generators (Exhibit A-12, Schedule B5.4, page 13, line 28)**

7 Rebuttal Issue 10: AG Witness Coppola's recommended disallowance for Portable
8 Generators.

9 **Q40. What is AG Witness Coppola's recommendation regarding Portable**
10 **Generators?**

11 A40. He recommends full disallowance of \$4,500,000 in 2024 for Portable Generators
12 on page 32, lines 16-17 of his testimony.

13

14 **Q41. Why does AG Witness Coppola make this recommendation?**

15 A41. He makes several arguments for full disallowance on page 32 of his testimony
16 including: generators cannot be used to power furnaces and air conditioners,
17 customers will not receive a generator during the first 48 hours of storm, demand
18 for generators is likely to outstrip the supply, gasoline delivery could be
19 compromised due to nearby gas stations being without power.

20

21 **Q42. Do you agree with AG Witness Coppola's arguments for disallowance?**

22 A42. No. While the generators cannot provide heating and cooling, they do provide
23 several benefits to customers. The generators will power medical devices for
24 vulnerable customers. They will also power appliances to preserve food and allow
25 meals to be cooked. A source of frustration for many customers is having to throw

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1 out spoiled food and the costs associated to repurchase; the generators will prevent
2 this and benefit our customers. Additional benefits include powering sump pumps
3 (to prevent home flooding) and enabling customers working from home to use their
4 internet services and computer devices.

5
6 I believe there may be a misunderstanding as to the second argument. The Company
7 does not wait 48-hours before deploying generators. For example, vulnerable
8 customers with medical devices can receive a generator if they need immediate
9 assistance. I explained in discovery response U-21534 AGDE-3.93a (Exhibit A-52,
10 Schedule QQ2) that when storms occur, the Company creates a list of all customers
11 likely to be without power for at least 48 hours, and immediately contacts customers
12 on this list to offer them a generator. It appears AG Witness Coppola interpreted
13 this to mean that generators are not deployed until after the first 48 hours of storm,
14 however, this is not the case.

15
16 As to the third point, the Company has not seen any indications that generator
17 demand will exceed supply thus far. Supply and demand will be monitored, and
18 the Company will adapt accordingly to serve our customers.

19
20 As to the fourth point, the Company has several options to ensure gasoline is
21 available. This includes utilizing gasoline from the Company's field service centers
22 (stored in large underground tanks) and deploying its employees and contractors to
23 areas where gas stations have power.

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1 The Company's customers have been impacted by outages resulting from
2 increasingly frequent and severe storms. Providing portable generators to the
3 Company's vulnerable customers during storm is an effective method for
4 mitigating some of the impacts of power disruptions. I believe that the additional
5 customer benefits are reasonable and prudent.

6

7 **Base Capital Programs 2023 Underspend**

8 Rebuttal Issue 11: AG Witness Coppola's recommended removal of 2023 Base
9 Capital Programs underspend.

10 **Q43. What is AG Witness Coppola's recommendation regarding 2023 Base Capital**
11 **Programs?**

12 A43. AG Witness Coppola recommends a disallowance of \$25,202,000 for Base Capital
13 Programs on page 34, lines 14-17 of testimony.

14

15 **Q44. Why does AG Witness Coppola make this recommendation?**

16 A44. AG Witness Coppola states:

- 17 • "In discovery, the Attorney General asked the Company to report on the
18 actual amount of capital expenditures incurred in 2023 in the Electric
19 Distribution area. The information provided in response to the discovery
20 request shows that for 2023 the Company incurred actual capital
21 expenditures for Base Capital Programs of \$806,973,000. In comparison,
22 the Company forecasted \$832,175,000 for the year. The difference of
23 \$25,202,000 should be removed from rate base in this rate case." (page 34,
24 lines 11-16)

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- 1 • “The Commission has previously ruled that underspent amounts 1 included
2 in projected rate base should be removed. Therefore, I recommend that the
3 Commission continue that practice and remove the \$25,202,000 from rate
4 base in this rate case.” (page 35, lines 1-3)
5

6 **Q45. Do you agree with AG Witness Coppola’s recommendation for this**
7 **disallowance?**

8 A45. Yes, the Company agrees this disallowance is reasonable and prudent.
9

10 **Capital Emergent Replacements Storm Testimony, Processes, and Reporting**

11 Rebuttal Issue 12: Staff Witness Duell’s recommended changes to testimony.

12 **Q46. What does Staff Witness Duell recommend regarding Capital Emergent**
13 **Replacements Storm testimony?**

14 A46. Staff Witness Duell says the following on page 8, lines 9-14 of testimony, “Staff
15 had difficulty finding in testimony from the Company a description stating what it
16 is spending storm restoration expenses on and what the Company defines as storm
17 restoration expense. Staff recommends that the Company provide a brief
18 description in future cases of what the Company defines as storm restoration
19 expenses and describe what the Company plans on spending their storm restoration
20 expenses on.”
21

22 **Q47. Do you agree with Staff Witness Duell’s recommendation?**

23 A47. Yes, I agree with Staff Witness Duell’s recommendation to improve testimony
24 describing the work performed under Emergent Replacements Storm.
25

Line
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1 Rebuttal Issue 13: MNSC Witness Denzler’s incorrect statement that field personnel
2 determining whether to repair or replace assets during storm enables the Company to
3 take advantage of this new cost share structure.

4 **Q48. What does MNSC Witness Denzler say regarding field personnel deciding**
5 **whether to repair or replace during Storm?**

6 A48. MNSC Witness Denzler says on page 6, line 19 and page 7, lines 1-4, “... the
7 Company has stated there is no current standard, other than field crew judgement,
8 on when to repair versus replace field assets, and has not conducted a cost/benefit
9 analysis to support any such decisions. Particularly with the absence of any
10 objective standard, the Company may alter Storm decision making to take
11 advantage of this new cost share structure.”

12

13 **Q49. Do you agree that field personnel deciding whether field assets are replaced or**
14 **repaired during storm enables the Company to advantage its cost structure?**

15 A49. No. The Company’s field personnel prioritize employee and public safety and
16 speed of power restoration during storms and make the decision between repairing
17 and replacing based on these factors.

18

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

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1 The Company provides field personnel supervision and training so that they are
2 equipped to make these decisions. It is reasonable to rely on the professional
3 judgment of trained experts, who work at the point of activity, and are therefore
4 best equipped to understand the condition of damaged assets in the field and
5 whether they can or cannot be repaired.

6

7 I provided an example in my direct testimony in Case No. U-21297 on page BLH-
8 32 on lines 12-17 which highlight the types of decisions that field personnel must
9 make at the point of activity, "The lineman arrives and immediately identifies a
10 broken insulator that is not securing the wire to the cross arm. As the lineman
11 ascends the pole, they then identify that the cross arm is rotted. At this time the
12 lineman would make the decision to replace both the insulator (the broken insulator
13 created the floating wire) and rotted cross arm. In this example, two pieces of
14 defective equipment was replaced."

15

16 Rebuttal Issue 14: MNSC Witness Denzler's recommendation to develop Storm
17 performance criteria.

18 **Q50. What does MNSC Witness Denzler recommend regarding Storm performance**
19 **criteria?**

20 A50. MNSC Witness Denzler recommends the following, "Order the Company to
21 develop a proposal to tie financial recovery from excess Storm spending to a
22 balanced set of relevant performance metrics to ensure an alignment of incentives,
23 using Storm performance criteria that include outage restoration, estimate accuracy,
24 resource productivity, and financial responsibility specific to Storm scenarios."
25 (page 19, lines 8-12)

Line
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1 **Q51. Do you agree with MNSC Witness Denzler's recommendation?**

2 A51. No. I believe this recommendation to be redundant because the Company already
3 has Service Quality and Reliability Standards (SQRS) which set standards of
4 service related to the frequency and duration of storm-related outages and because
5 Case No. U-21400 is still pending which is related to Performance Based
6 Ratemaking.

7
8 **Q52. Should the Commission adopt MNSC Witness Denzler's recommendation to**
9 **require more Storm metrics reporting?**

10 A52. No. I believe these to be redundant given the SQRS and pending Performance
11 Based Ratemaking in Case No. U-21400.

12

13 **Contributions in Aid of Construction (CIAC)**

14 Rebuttal Issue 15: MNSC Witness Denzler's recommendations regarding CIAC.

15 **Q53. What does MNSC Witness Denzler recommend regarding CIAC?**

16 A53. MNSC Witness Denzler makes two recommendations regarding CIAC:

17

- 18 • "To ensure that implemented CIAC accurately reflects the current costs of
19 construction and desired contributions, I recommend the Commission order a
20 report in the next rate case proceeding detailing the impact of the CIAC
21 changes. This should include a review of the new business construction costs
22 and CIAC received, with comparison to historic and projections of future new
23 business construction costs and CIAC received." (page 11, lines 4-8)
- 24 • "Additionally, the Commission should ensure that CIAC sees regular updates
25 in the future so that it does not drift so far from actual costs again. To this end,

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1 I recommend the Commission order a regular review of CIAC costs. I
2 recommend a review cadence of at least once every two years, but certainly no
3 longer than once every five years.” (page 11, line 9-12)

4

5 **Q54. Do you agree with MNSC Witness Denzler’s recommendation for the**
6 **Company to provide a report in its next rate case that details the impact of**
7 **CIAC changes?**

8 A54. No. This information is provided in the Company’s publicly available Exhibit A-
9 12, Schedule B5.4 for each rate case.

10

11 **Q55. Do you agree with MNSC Witness Denzler’s recommendation that regular**
12 **reviews of CIAC are appropriate?**

13 A55. Yes, the Company agrees it is reasonable and prudent to have regular CIAC reviews
14 and believes a five-year cadence is appropriate.

15

16 Rebuttal Issue 16: AA Witness Stults’s recommendation regarding CIAC.

17 **Q56. What does AA Witness Stults recommend regarding CIAC?**

18 A56. AA Witness Stults states, on page 26, lines 9-19 of testimony, “I recommend the
19 CIAC be no more than it would be if the site were served by a 13.2kV system – that
20 is the Company should cover the costs for increasing the capacity in the area by 2.5
21 times before any CIAC is charged to the developer for increased capacity. A
22 developer should not have to pay the cost differential necessary to increase the
23 capacity from that of a 4.8kV system to that of a 13.2kV system. Requiring the
24 developer to cover this cost differential is unreasonable because it unfairly favors
25 projects in newer communities and discourages increasing development density in

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1 older cities like Ann Arbor, Detroit, Grosse Pointe, and Highland Park that have
2 not yet been upgraded to a 13.2kV system. However, ratepayers as a whole benefit
3 from increased density by reducing the infrastructure needed to serve the customer
4 base. Thus, it is to everyone's benefit not to adopt a policy that effectively
5 encourages sprawl."

6

7 **Q57. Do you agree with AA Witness Stults that the Company's CIAC rates are**
8 **unfair for customers on 4.8kV circuits?**

9 A57. No. The Company is not aware of situations in which similarly situated customers
10 on the 4.8kV and 13.2kV systems have paid substantially different CIAC fees based
11 on the voltage of the system they are connected to. There are many factors such as
12 existing circuit and/or substation conditions, as well as customer load
13 characteristics which contribute to the potential CIAC a developer is responsible
14 for because of the impact their load addition has on the system (and thus other
15 customers). Not charging developers for their share of required system upgrades
16 and extensions will shift that burden to all customers, including the most
17 vulnerable.

18

19 **Q58. Does this conclude your rebuttal testimony?**

20 A58. Yes.

21

1 JUDGE WALLACE: All right. Please go
2 ahead.

3 MS. REITZEL: Thank you, your Honor. And
4 last, but not least, DTE would now like to bind into the
5 record the Direct Testimony of Robert A. Bellini, which
6 consists of a cover sheet and 46 pages of questions and
7 answers, as well as 13 direct exhibits and schedules,
8 designated as Exhibit A-12 Schedule B5.5, Exhibit A-13
9 Schedule C5.6, Exhibit, Revised Exhibit A-16 Schedule F3,
10 Exhibit A-16 Schedule F8, Exhibit A-25 Schedule 01,
11 Exhibit A-25 Schedule 02, Exhibit A-25 Schedule 03,
12 Exhibit A-25 Schedule 04, Exhibit A-25 Schedule 05,
13 Exhibit A-25 Schedule 06, Exhibit A-25 Schedule 07,
14 Exhibit A-25 Schedule 08, and Exhibit A-25 Schedule 09.
15 Mr. Bellini also has rebuttal testimony, consisting of a
16 cover sheet and 39 pages of questions and answers, as
17 well as 11 rebuttal exhibits, designated as Exhibit A-40
18 Schedule EE1, Exhibit A-40 Schedule EE2, Exhibit A-40
19 Schedule EE3, Exhibit A-40 Schedule EE4, Confidential
20 Exhibit -- sorry, Confidential Exhibit A-40 Schedule EE5,
21 Exhibit A-40 Schedule EE6, Exhibit A-40 Schedule EE7,
22 Exhibit A-40 Schedule EE8, Exhibit A-40 Schedule EE9,
23 Exhibit A-40 Schedule EE10, and Exhibit A-40 Schedule
24 EE11.

25 I also would note that we would move to
Penn Reporting, LLC - lori.penn@yahoo.com

1 admit Exhibit A-54 pursuant to an agreement with
2 Ms. Brader on behalf of MAUI and the City of Ann Arbor.

3 JUDGE WALLACE: O.K. Is there any
4 objection to binding in the direct and rebuttal testimony
5 of Mr. Bellini?

6 Hearing none, the testimony is bound in.

7 Is there any objection to the admission
8 of, and I've got A-54 noted here, to the exhibits and
9 associated schedules sponsored by Mr. Bellini? (No
10 response.)

11 (Testimony bound in.)

12 - - -
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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
DIRECT TESTIMONY
OF
ROBERT A. BELLINI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT A. BELLINI

Line
No.

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

2 A1. My name is Robert A. Bellini (he/him/his). My business address is 8001 Haggerty,
3 Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE
4 Electric or Company) as Manager of Community Lighting.

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 Central Michigan University with a Bachelor of Science degree
11 in Business Administration in 1999. In 2005, I graduated from Oakland University,
12 with a Master of Accountancy degree.

13

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

15 A4. From 2005 until 2008, I was employed by Deloitte & Touche LLP as a Financial
16 Auditor. While employed at Deloitte & Touche, I passed the Certified Public
17 Accountant (C.P.A.) examination and became a licensed C.P.A. in 2007. In 2007,
18 I was promoted to Senior Auditor on client engagements. In this role, I was
19 responsible for tailoring each audit based on a client's industry and the risks
20 inherent in their operations, supervising the audit fieldwork, and communicating
21 the audit issues and results with client management.

22

23 In 2008, I joined DTE Energy as a Financial Auditor. My responsibilities included
24 executing both financial and Sarbanes-Oxley (SoX) audits in support of the DTE

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1 Energy 10-K annual filing under the guidance of our external auditor,
2 PriceWaterhouseCoopers (PWC). In 2010, I was promoted to Senior Auditor. My
3 responsibilities included planning, scoping, and executing both financial and
4 operational audits. In 2013, I was promoted to Principal Supervisor of the Joint
5 Use department. My responsibilities included developing budgets, forecasting, and
6 negotiating joint use agreements with various attaching entities. In 2016, I was
7 promoted to Manager, Joint Use. In 2018, I was promoted to Manager, Community
8 Lighting.

9

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

12 A5. Yes. I am a registered Certified Public Accountant (CPA).

13

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

15 A6. I am currently responsible for managing the marketing and sales, budgeting and
16 forecasting, planning and construction and asset management for approximately
17 199,000 DTE Electric-owned streetlights and outdoor protective lights (OPLs). I
18 also manage the maintenance and provision of energy to municipally owned
19 streetlights and the provision of energy-only service to municipalities, in
20 accordance with DTE Electric's MPSC-approved tariffs. DTE Electric's assets
21 related to these services include mercury vapor, metal halide, high pressure sodium,
22 and light-emitting diode (LED) luminaires.

23

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

Line
No.

1 A7. Yes. I have sponsored testimony in the following cases:

2 U-20561 2019 DTE Electric General Rate Case

3 U-20836 2022 DTE Electric General Rate Case

4 U-21297 2023 DTE Electric General Rate Case

5

6 **Purpose of Testimony**

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

8 A8. The purpose of my testimony is to support the following topics related to DTE
9 Electric's lighting assets: a) cost recovery of O&M and capital expenditures, and
10 b) rate design. Specifically, I will discuss the following issues:

- 11 • Describe the portfolio of Community Lighting assets;
- 12 • Support the sales forecast for the various outdoor lighting rates including
13 automated traffic signal (ATS) rates and metered street lighting rates;
- 14 • Describe the Company's preventative maintenance programs;
- 15 • Discuss the Company's outage restoration activities;
- 16 • Support and discuss the Company's actual Community Lighting O&M
17 expenses for the historical period which ended December 31, 2022, and the
18 projected Community Lighting O&M expenses for the 12-month projected
19 test period ending December 31, 2025;
- 20 • Support and discuss Community Lighting's actual capital expenditures for
21 the historical period which ended December 31, 2022, and the projected
22 Community Lighting capital expenditures for the 12-month projected test
23 period ending December 31, 2025;

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- 1 • Discuss the reasonableness of DTE's LED selection methodology as it
- 2 relates to HID to LED conversions, as well as the disallowance of LED plant
- 3 costs as ordered in Case No. U-21297;
- 4 • Discuss the sunseting of Community Lighting's installation and
- 5 maintenance of high-pressure sodium (HPS) technology, and proposed
- 6 tariff changes;
- 7 • Discuss the status of municipal streetlight outage reporting and proposed
- 8 tariff changes as ordered by the MPSC Commission in Case No. U-21297;
- 9 • Support the proposed rate design for the outdoor lighting (municipal and
- 10 other) and ATS tariff offerings using the lighting model.

11

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

13 A9. Yes. I am sponsoring in whole, or in part, the following exhibits:

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-12	B5.5	Projected Capital Expenditures – Community
16			Lighting
17	A-13	C5.6	Projected Operation and Maintenance
18			Expenses – Distribution Expenses
19	A-16	F3	Present and Proposed Revenues by Rate
20			Schedule – 12 months ending December 31,
21			2025
22	A-16	F8	Proposed Tariff Sheets
23	A-25	O1	Community Lighting Outdoor Lighting
24			Outage Duration

Line
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1	A-25	O2	Community Lighting Outdoor Lighting
2			Outage Cost
3	A-25	O3	HPS to LED Customer Notification Letter
4	A-25	O4	WP Calculation of \$5.8M Disallowance by
5			MI-MAUI in U-21297
6	A-25	O5	Don McLean DTE HID-LED Selection
7			Methodology Opinion Letter
8	A-25	O6	DMD – Intersection Performance Summary
9	A-25	O7	DMD – Revised Rdwy Performance
10			Summary
11	A-25	O8	Don McLean_Curriculum Vitae
12	A-25	O9	Gibbons – DTE Energy Response Document
13			& CV

14

15 I am sponsoring line 23 within Exhibit A-13, Schedule C5.6, page 1 of 2, and the
 16 pages specific to the residential and commercial outdoor protective lighting (OPL)
 17 and municipal classes within Exhibit A-16, Schedule F3. This includes pages 46
 18 through 57. On Exhibit A-16, Schedule F8, I sponsor the OPL and municipal
 19 tariffs, while Company Witness Willis sponsors the tariffs for the remaining
 20 customer classes.

21

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

23 A10. Yes, they were.

Line
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1 **Community Lighting Assets**

2 **Q11. Could you describe the portfolio of Community Lighting assets that DTE**
3 **Electric owns, operates, and maintains on behalf of its customers?**

4 A11. DTE Electric owns, operates, and maintains approximately 199,000 Community
5 Lighting assets which serve municipal, commercial, and residential customers.
6 Additionally, there are approximately 82,000 streetlights which are owned by
7 municipal customers (E1 Option III), and approximately 6,400 municipal-owned
8 Automated Traffic Signals (E2). Municipal streetlights (E1 Option I and II) include
9 roadway and residential streetlights within municipal and/or city limits. These
10 streetlights owned by DTE Electric are installed at the request of the city or
11 municipality. DTE Electric also installs Outdoor Protective Lighting (OPL) for
12 commercial (D9 Commercial) and residential (D9 Residential) customers.
13 Examples of commercial OPL solutions include parking lot lighting systems (i.e.
14 restaurants or strip malls) and residential OPL solutions such as lights installed on
15 a customer's property. Ownership of Community Lighting assets is detailed in
16 Table 1 below:

Table 1: Community Lighting Assets¹

Asset Type	Asset Ownership	Rate Type	# Of Assets	Description
Municipal OH & UG Streetlights	DTE Electric	E1 Option I	165,932	DTE Electric owned and maintained system
Municipal OH & UG Streetlights	Customer	E1 Option II	119	Municipal owned and DTE Electric maintained system
Municipal OH & UG Streetlights	Customer	E1 Option III	82,399	Municipal owned and maintained system
Commercial Outdoor Protective Lights	DTE Electric	D9	24,179	DTE Electric owned and maintained equipment
Residential Outdoor Protective Lights	DTE Electric	D9	9,147	DTE Electric owned and maintained equipment
Municipal Automated Traffic Signals (ATS)	Customer	E2	6,436	Municipal owned and maintained equipment

¹ Light counts as of November 1st, 2023

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1 **Q12. Briefly describe the various lighting technologies in service and the movement**
2 **toward more energy-efficient Company-owned LED lighting technology.**

3 A12. There are 4 lighting types currently in use within DTE Electric's service territory:
4 Light Emitting Diode (LED), High Pressure Sodium (HPS), Metal Halide (MH),
5 and Mercury Vapor (MV), the first three of which are still actively maintained and
6 installed upon request. LED lighting is the most energy efficient lighting type
7 available, while the remaining light types are less efficient in terms of energy
8 consumption (MV is the least efficient of the 4 light types).

9
10 Pursuant to the Energy Policy Act of 2005, Mercury Vapor lamps became obsolete
11 due to their inefficient use of energy and inclusion of mercury as a component, and
12 effective January 2008, were banned from production in the United States. At the
13 end of 2007, MV's comprised almost 52% of DTE Electric's company owned
14 lighting assets, and the balance consisted primarily of HPS lighting (a nominal
15 number of lights were MH at the time). DTE Electric began to convert failed MV
16 lighting to LED for E1 Option I customers starting in 2017 in accordance with the
17 Commission's order on January 31, 2017, in Case No. U-18014.

18
19 The Company has worked closely with its municipal partners, commercial and
20 residential customers over the past decade as they transition to LEDs as a preferred
21 lighting technology. In 2022, the Southeast Michigan Council of Governments
22 (SEMCOG) made available grant funding for several types of carbon reduction
23 initiatives, which included municipal lighting conversions to LEDs. DTE made
24 aware and assisted several communities to complete their applications. In 2023,
25 almost \$3.4M in grant funds were awarded to several DTE municipal customers to

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1 help fund HID to LED conversion projects totaling approximately 11,000 lights
2 anticipated between 2024 – 2025. Table 2 below provides a snapshot of the changes
3 over time in DTE Electric’s company owned lights, from 2012 to 2023:
4

Table 2: Community Lighting Assets by Lighting Type (2012-2023)²

Lighting Type	2012	2017	2023
Light Emitting Diode (LED)	2,851 (1%)	53,018 (27%)	124,565 (62%)
High Pressure Sodium (HPS)	98,070 (49%)	91,422 (46%)	53,374 (27%)
Mercury Vapor (MV)	94,681 (48%)	52,518 (26%)	19,895 (10%)
Metal Halide (MH)	2,977 (2%)	2,468 (1%)	1,622 (1%)
Total Assets	198,579	199,426	199,377

5

6 **Q13. Can you provide an overview of the various lighting technologies employed**
7 **within DTE’s Municipal Street Lighting Business, E1 Option I?**

8 A13. The current lighting portfolio for street lighting customers served on DTE Electric’s
9 E1 Option I Rate Schedule referenced in Table 1 above, includes approximately
10 166,000 total Company owned lights as of November 1st, 2023. Table 3 below
11 shows the light type breakout by total count and percentage:
12

Table 3: E1 Option I Light Counts by Type

Lighting Type	Asset Count	% of Total Assets
Light Emitting Diode (LED)	113,584	69%
High Pressure Sodium (HPS)	40,417	24%
Mercury Vapor (MV)	10,695	6%
Metal Halide (MH)	1,355	1%
Total E1 Option I Assets	166,051	100%

² Light counts as of November 1st, 2023.

Line
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1 While the quantity of high-pressure sodium and mercury vapor luminaires has been
2 steadily dropping over the past several years, the total number of LED luminaires
3 continues to increase in-kind due primarily to municipal driven conversions. Metal
4 halide lighting luminaires represent approximately 1,400, or less than 1% of DTE
5 Electric's company owned lighting luminaires. As noted earlier, more than 20% of
6 the remaining non-LED municipal streetlights are targeted for conversion to LED
7 as a result of the recently awarded SEMCOG project grants.

8

9 **Q14. Can you provide an overview of the various lighting technologies for street**
10 **lights that are municipality owned (E1 Options II & III)?**

11 A14. The lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of 85
12 (71%) high pressure sodium lights and 34 (29%) mercury vapor lights. As
13 previously indicated, this service has been closed to new customers since 2009, and
14 existing E1 Option II Rate Schedule customers electing to convert to LED are
15 required to convert to DTE Electric's E1 Option I or Option III Rate Schedules.
16 The mix of lighting for DTE Electric's E1 Option III Rate Schedule includes
17 approximately 70,000 (84%) LED luminaires, 12,000 (15%) high pressure sodium
18 luminaires, and the remainder consisting of MV and MH lighting. The high
19 concentration of energy-efficient LED lighting in this class reflects the City of
20 Detroit's conversion of most of its streetlights to LED.

21

22 **Q15. Can you provide an overview of DTE Electric's Community Lighting D9 OPL,**
23 **E2 ATS, and E1.1 metered municipal-owned lights rate schedules?**

24 A15. DTE Electric's D9 OPL rate schedule and its proposed pricing reflect recovery of
25 costs associated with the ownership, maintenance, and provision of energy to a

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1 portfolio of approximately 24,000 commercial and 9,000 residential outdoor
2 protective lights. OPL lighting uses the same technologies as streetlighting and,
3 consistent with conversions of failed mercury vapor streetlights to LED, the
4 Company began converting failed mercury vapor OPLs to LED starting in February
5 2017.

6

7 DTE Electric's E2 Rate Schedule and proposed pricing reflect the recovery of costs
8 for the production and distribution of energy for automated traffic signal (ATS)
9 lights owned and maintained by municipalities and other public authorities.

10 DTE Electric also provides metered, municipal-owned streetlight service under the
11 E1.1 Rate Schedule. I support the energy forecast for this Rate Schedule and
12 Witness Willis supports the proposed rate for this service.

13

14 **Q16. Is DTE Electric proposing any changes with respect to the maintenance and**
15 **installation of HPS lighting technology?**

16 A16. Yes. In 2023, our key lighting vendors informed us that they will be or are
17 considering phasing out their HPS product lines in 2024. Given the continued
18 movement toward LED technology, we have decided to sunset our active
19 maintenance and support for HPS fixtures effective the earlier of January 1st, 2025,
20 or depletion of remaining HPS inventory. We have discontinued the purchase of
21 all HPS stock effective November 2023.

22

23 **Q17. Why has the Company decided to wait until 2025 to stop maintaining HPS**
24 **fixtures?**

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1 A17. Similar to the approach taken by the U.S. Department of Energy (DOE) in its April
2 2022 announcement of the phaseout of most incandescent lightbulbs that went into
3 effect mid-2023, we've elected to wait until 2025 to formally adopt this change.
4 This will allow time to 1) inform our customers of this change in policy and address
5 any concerns they may have, and 2) provide our customers time to socialize this
6 change with stakeholders within their communities. Though there has been broad
7 community support in the adoption of LED lighting technology, it is not
8 unanimous. Therefore, the remaining inventory will be used to accommodate these
9 requests in the short term and further support an orderly transition to LEDs. We
10 will continue to maintain HPS lights as currently proscribed in the tariff throughout
11 2024 unless HPS stock has been depleted prior to 2025.

12

13 **Q18. How is the Company proposing to manage replacement of HPS fixtures that**
14 **require maintenance upon depletion of stock or after 2024?**

15 A18. Similar to its policy for MV fixtures, DTE is proposing to maintain HPS fixtures
16 through replacement upon failure with equivalent LED luminaires at no additional
17 charge to the customer. In support of this transition, the Company has also decided
18 to offer a HPS per light labor credit starting in 2024 for those municipalities that
19 have decided to proactively convert to LEDs for which projects have not yet begun.
20 The labor credit of \$65 is the same as the MV labor credit applied to such
21 conversions.

22 **Q19. What steps has the Company taken to inform its' municipal customers of this**
23 **change?**

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1 A19. In November of 2023, DTE notified all of its' municipal customers which continued
2 to take service from HPS fixtures via email with an attached letter (Exhibit A-25
3 O3). This letter highlighted why the change was occurring, the transition period
4 mentioned above, the benefits of LEDs, and lastly, the new labor credit being
5 offered for HPS to LED conversions.

6

7 **Q20. Are you proposing any changes to the E1 Option I and D9 tariff language?**

8 A20. Yes. We are proposing to include the following language for both E1 Option I and
9 D9 tariff options: *"Effective January 1st, 2025, new high pressure sodium (HPS)*
10 *fixtures will no longer be available. Customers with existing HPS fixtures will*
11 *continue to receive service until those fixtures fail. At that time, the fixture will be*
12 *converted to an LED luminaire."*

13

14 **Community Lighting Sales Forecast**

15 **Q21. How did you develop the Lighting sales forecast for E1 Options I & II?**

16 A21. Consistent with the methodology utilized in prior Company electric rate cases, the
17 sales forecast for the E1 Option I & II Rate Schedules were developed by first
18 preparing a forecast of light counts for each lighting type (technology and wattage
19 size) for the projected test period based upon: (1) known projects, (2) continued
20 conversions of mercury vapor lighting to LED lighting, and (3) an estimate of
21 increased light counts net of removals, resulting from sales growth. The system
22 wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting
23 type was applied to the forecasted volume of lights for each lighting type. Annual
24 usage was assumed to be 4,200 hours, to reflect the hours that the lights on either
25 the dusk to dawn or standard provision are illuminated. The energy forecast for

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1 lights on the dusk to midnight provision was based upon 2,100 hours use and the
2 energy forecast for lights on the de-energized provision is zero. Lastly, pursuant to
3 the order in Case No. U-21297, we reduced the E1 Option I annual usage of 4,200
4 hours (dusk to dawn) and 2,100 hours (dusk to midnight) by 3.25% to account for
5 lights that are non-operational throughout the course of the year. This adjustment
6 is reflected within my workpapers titled "U-21534 Lighting Forecast" and "U-
7 21534 Lighting Rate Model."

8

9 **Q22. How did you develop the Lighting sales forecast for E1 Option III, D9, E2, and**
10 **E1.1?**

11 A22. The sales forecast for the E1 Option III Rate Schedule was developed by first
12 preparing a forecast of light counts for each of the lighting types for the projected
13 test period based upon known municipal-owned streetlighting projects and an
14 estimate of light count changes. The system wattage value applicable to each
15 lighting type was applied to the forecasted volume of lights for each lighting type
16 for the 4,200 hours for which all the lights are illuminated on an annual basis.

17

18 The total sales forecast for the OPL D9 Rate Schedule was developed by preparing
19 a forecast of light counts for each of the lighting types for the projected test period
20 based upon existing light counts, an estimate of increased light counts resulting
21 from sales growth net of removals, and continued conversions of mercury vapor
22 lighting to LED lighting. The system wattage value applicable to each lighting type
23 was applied to the forecasted volume of lights for each lighting type for the 4,200
24 hours for which the lights are illuminated on an annual basis.

25

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1 The sales forecast for the E2 ATS Rate Schedule was determined by using the total
2 connected wattage, as of November 2023, for the rate schedule and determining the
3 annual usage based upon that determinant. In other words, it is simply the product
4 of the total reported wattage and the total number of hours in the projected test
5 period.

6

7 The total sales forecast for the E1.1 Rate Schedule was based upon annualized
8 usage data for the 12-month period that ended June 2023.

9

10 **Company Preventative Maintenance Programs**

11 **Q23. What preventative maintenance programs does the Company manage and**
12 **how are the related expenses classified?**

13 A23. The Company manages the following preventative maintenance programs: 1) Post
14 Inspections, 2) Post Painting, 3) Night Patrol, 4) Post Replacement, and 5) Cable
15 Replacement. The Post and Cable Replacement programs are considered capital
16 expenditures while the remaining programs are booked as O&M.

17

18 **Q24. Please describe the Company's Post Inspection program and its relationship**
19 **to the Post Painting and Post Replacement programs.**

20 A24. DTE Electric owns more than 60,000 decorative metal posts and has established
21 detailed post inspection criteria to inspect its posts every three years to both identify
22 posts whose structural integrity dictates their replacement (condemnation), and
23 posts that require painting. At the time posts are inspected, minor post maintenance
24 work such as adding or replacing post asset tags, post hand-hole covers, and T-box
25 door covers may also be completed. Over the past three years, DTE Electric's

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1 decorative post inspection process has resulted in the annual replacement of
2 condemned posts at a rate of approximately 3% and post painting at a rate of
3 approximately 2% relative to the total population of posts.

4

5 **Q25. Does the Company also inspect its streetlight-only wood poles?**

6 A25. Yes. Our streetlight-only wood poles are inspected as part of DTE's pole top
7 maintenance (PTM) program managed by Distribution Operations. As wood poles
8 are inspected through this program, streetlight-only wood poles identified as
9 condemned or near end-of-life, are sent to DTE – Community Lighting for
10 replacement by its' contractor(s) responsible for replacing our decorative metal
11 posts.

12

13 **Q26. Please describe the Company's Night Patrol program and its purpose.**

14 A26. To further bolster customer service and reliability, the Company implemented a
15 Night Patrol program in 2019 with the intent to proactively identify municipal-wide
16 outages which would then be routed to a DTE authorized construction crew for
17 repair. All of DTE's E1 Option I streetlights are within the scope of this program,
18 and depending on prior patrol results and repair detail (i.e. large percentage of
19 outages noted in a single municipality or high concentration of outages in a specific
20 area), the Company may adjust the timing of the next scheduled night patrol.

21 In 2022, DTE developed a night patrol database to record details by light and by
22 circuit as to the nature and recurrence of outages. The purpose of cataloging this
23 data is to allow the Company to utilize analytics to identify repeat visits to the same
24 luminaire or problematic circuits because of underground cable failures.

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1 **Q27. Why did the Company launch the Cable Replacement program which targets**
2 **underground cable replacements?**

3 A27. As more outage data continues to be collected from the Night Patrol program, we
4 are beginning to identify root cause issues through direct feedback from our
5 contractors tasked with restoring service, and data on specific lights and circuits
6 that indicate recurring outages. In general, outages are the result of 1) a failed
7 luminaire, 2) failed wiring or components such as a photocell, or 3) failed
8 underground cable.

9
10 This program specifically targets underground cable replacement work as this tends
11 to be the costliest type of repair to perform on a reactive basis and has a higher
12 likelihood to impact multiple lights when the cable begins to fail. Repairing larger
13 stretches of cable using a data driven approach on a planned basis through this
14 program is not only more cost effective, but is also anticipated to reduce the
15 likelihood of one or more lights failing due to an underground fault once replaced,
16 thereby increasing reliability.

17
18 **Q28. You mentioned that proactive underground cable replacement work is more**
19 **cost effective than reactive repairs. Can you elaborate?**

20 A28. When responding to outage events that involve underground cable failures as the
21 root cause, our repair crew's primary objective is to address the immediate issue
22 and restore service as quickly as possible. This increases the number of "locate and
23 repairs" which result in sections of failed cable being isolated and replaced. Though
24 this addresses the immediate root cause, it doesn't necessarily increase the

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1 longevity of the stretch of cable supporting that circuit, in a manner that replacing
2 failed or end-of-life underground cable would.

3

4 **Q29. Are there any other long-term benefits expected to be realized from the Cable**
5 **Replacement program?**

6 A29. Yes. First, most of the underground system cable that is currently in service is direct
7 buried, meaning that the cable is unsleeved and buried at a depth which makes it
8 more susceptible to freezing and thawing impacts as well as 3rd party strikes during
9 excavation work (i.e. other utility work or municipal driven projects such as road
10 widening). Cable that is replaced under this program is now installed within a
11 protective sleeve which increases the likelihood that it can survive a 3rd party strike
12 or become exposed through excavation. Second, as damaged and end-of-life cable
13 is replaced with newly installed and protected cable, we expect to see a reduction
14 in outages whose root cause is determined to be an underground cable failure. Over
15 time, this will reduce the number of reactive underground cable events and increase
16 lighting system reliability.

17

18 **Outage Restoration Activities**

19 **Q30. What was DTE Electric's performance with respect to outage duration for its**
20 **lighting customers?**

21 A30. DTE Electric's 2022 performance was 4.2 calendar days. These historical metrics
22 for outage duration and defects are displayed on Exhibit A-25, Schedule O1.
23 In addition to weather-related events, "long duration" and "follow-up" outage
24 events include extended repair time for underground faults (i.e. Miss Dig permits),
25 repairs resulting from third party damage, and lack of special order material (SOM)

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1 maintained by a city or municipality. The performance metrics only include
2 reactive street light outage repairs; they do not include any outage repair resulting
3 from patrol and fix activities. However, Exhibit A-25, Schedule O1 does reflect
4 the total number of lights canvassed from the night patrol program as well as the
5 number of outages identified from these patrols. Street light outage events reported
6 on weekends and after normal week-day business hours are analyzed and
7 dispatched to crews on the following business day. DTE Electric measures both
8 total and crew duration cycle repair periods. Crews authorized by DTE Electric
9 work to complete reactive outage repairs of reported street light outage events.

10

11 **Q31. What other measures does DTE Electric have in place to improve its**
12 **restoration time and to maintain a high level of customer service?**

13 A31. Restoration performance, among other metrics, are reviewed with our contractors
14 at monthly performance meetings and, to the extent that restoration performance is
15 not meeting expectations, DTE Electric can shift restoration work as needed to
16 alternate contractors to achieve the desired restoration performance. Internally, the
17 Company evaluates contractor performance metrics on a weekly basis to identify
18 potential performance issues or problem-solving opportunities. In addition to these
19 efforts, the Company continues to improve the arrangements for the provision of
20 special-order materials on behalf of municipalities that choose streetlight materials
21 that are not included in DTE Electric's standard streetlight offerings.

22

23 **Q32. Could you please summarize DTE's Outage Performance over the past six**
24 **years?**

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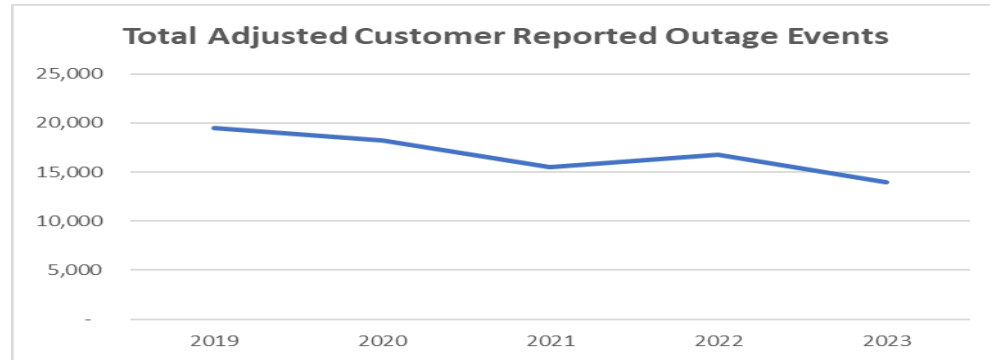
1 A32. While any individual year will be impacted by external factors such as changing
2 weather patterns (i.e. more freezing and thawing leads to increased cable faults) and
3 number of catastrophic storms (i.e. construction crews being diverted to assist in
4 power restoration activities), key outage metrics continue to trend in a positive
5 direction when evaluating performance collectively, over the past six years.
6 Specifically, the outage data summarized in Exhibit A-25, Schedule O1 indicates
7 a positive impact in terms of the correlation between our proactive efforts resulting
8 from the night patrol & underground cable replacement programs to reduce
9 customer reported outage events (when adjusting for the removal of “ok on
10 arrivals” and “streetlight knockdowns” and adding “follow-up events completed)
11 from approximately 19,500 in 2019 to approximately 14,000 in 2023 as Chart 1
12 below illustrates:

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1

Chart 1: Total Adjusted Customer Reported Outage Events

2



3

4 As we collect more night patrol data, we will continue to use this data to
5 strategically target municipalities based on historical results.

6

7 **Q33. Were there any requirements as part of the order in Case No. U-21297**
8 **pertaining to DTE making streetlighting outage reports available to**
9 **municipalities that request them?**

10 *A33.* Yes. Specifically, the Order on page 373 states "...DTE Electric Company shall
11 work with interested stakeholders to develop a streamlined streetlight outage report
12 request process, a standard report request process, a standardized report format,
13 data protocols, and delivery method and shall update its E1 tariff to reflect the
14 following:

15 *Any E1 streetlight customer may request to receive from the company a*
16 *calendar-year report, to be delivered by the company on or before*
17 *February 28 of the following year, providing, at a minimum, streetlight*
18 *outage occurrence counts, average outage durations and counts of*
19 *outages lasting longer than 14 days, covering all E1 streetlights served*
20 *under all of the customer's accounts. Customers with more than 5,000*
21 *E1 streetlights, may request to receive quarterly reports containing the*
22 *same information, to be delivered by the company within two months of*
23 *the end of each calendar quarter."*

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1 **Q34. What modifications are you proposing to the tariff language as provided in the**
2 **Order?**

3 A34. We propose clarifying that outage reporting will only be available for E1 Option I
4 customers, as these are the only streetlights within E1 that the Company owns,
5 operates, and maintains.

6

7 **Q35. When do you anticipate implementing this new process and making this**
8 **outage report available to requesting municipalities?**

9 A35. We have been working toward developing an outage report for municipalities that
10 includes 1) streetlight outage occurrence counts, 2) average outage durations, and
11 3) counts of outages lasting longer than 14 days. A meeting with MPSC Staff,
12 MAUI, and other interested stakeholders is scheduled end-March 2024 to share our
13 proposed reporting template which provides the outage data required by the order
14 in Case No. U-21297. Our goal is to collectively agree upon the reporting
15 framework, content, delivery, and effective date for implementation. Our new
16 reporting system discussed below, will help to streamline the process of preparing
17 the outage reports once the system has been tested and debugged.

18

19 **Q36. Can you provide an overview of the Company's new outage management**
20 **system?**

21 A36. In late 2023, Community Lighting began its transition to a standalone outage
22 management system (OMS), KloudGin. Initially part of the Advanced Distribution
23 Management System (ADMS) solution, this standalone OMS system will enable
24 us to issue outage work to our contractors more efficiently, increase our ability to
25 remove duplicate events (i.e. same outage reported by multiple parties), and when

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1 fully functional, allow for enhanced automation for outage reporting by
2 municipality.

3

4 **Q37. What is the status of the new OMS system and when do you expect it to be**
5 **fully functional?**

6 A37. The remaining work of integrating this OMS system into our operations is expected
7 to be completed by the end of Q1 2024. Once completed, our group will need to
8 work with our IT group and the software vendor to stress test this software to
9 identify and correct errors and issues. We are tentatively aiming to have the
10 software being fully functional by Q2 or Q3 2024. Once fully operational, our goal
11 for this system to be able to automate the outage reporting by municipality in
12 compliance with the Case No. U-21297 order.

13

14 **Q38. What was Community Lighting's spend with respect to outage restoration**
15 **activity?**

16 A38. In 2022, DTE Electric's Community Lighting team spent approximately \$8.1
17 million on outage restoration expense with approximately 76% of this cost being
18 capitalized, and the balance being recorded as O&M. The outage restoration
19 expense was approximately \$7.6 million in 2021. Exhibit A-25, Schedule O2
20 reflects DTE Electric's historical performance for outage restoration cost per event.

21

22 **Q39. Please explain the difference between capitalized outage expenses and non-**
23 **capitalized, or O&M outage expenses.**

24 A39. Outage restoration activities include remediating identified lighting outages that
25 could range from replacement of small wiring or lighting components to

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1 replacement of system cable, posts, and luminaires. Any repair (inclusive of both
2 materials and labor) that does not extend the useful life of the lighting asset (small
3 wiring or lighting components such as a replacement of a fuse) is considered an
4 O&M expense. All other repairs (both materials and labor) are considered capital
5 expenditures.
6

7 **Community Lighting Operations & Maintenance and Capital Expenditures**

8 **Q40. What is included in the Operations & Maintenance of Street Lighting and**
9 **Signal Systems account on line 23 of Exhibit A-13, Schedule C5.6, page 1?**

10 A40. Line 23 on this exhibit shows the projected O&M expenses which are directly
11 assigned to Account 596, Maintenance of Street Lighting and Signal Systems. This
12 account represents preventive maintenance expense, labor expense and non-
13 capitalized outage restoration expense. The preventive maintenance work includes
14 post inspection, post painting, and night patrols for DTE owned municipal
15 streetlights. The labor expense primarily reflects the labor of the Community
16 Lighting team including sales, planning, asset maintenance, construction, and asset
17 engineering. As reflected on Exhibit A-13, Schedule C5.6, the historical period
18 O&M expense of \$4.0 million is adjusted first for normalization attributable to an
19 anticipated reduction in O&M related outage spend of \$0.25 million, and then for
20 inflation of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025. This results in
21 a forecasted O&M expense of \$4.1 million in the projected test period.
22

23 **Q41. What are the Community Lighting capital expenditures on Exhibit A-12,**
24 **Schedule B5.5, “Projected Capital Expenditures – Community Lighting”?**

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1 A41. Capital expenditures for Community Lighting for 2022 were \$17.8 million. The
2 2022 expenditures included approximately \$6.3 million for new installations and
3 replacements, \$7.4 million for outage restoration, \$1.7 million for cable
4 replacements, \$1.5 million for post replacements, and \$0.9 million for planned HID
5 to LED conversions.

6

7 The projected capital expenditures for Community Lighting are \$16.7 million for
8 2023, \$16.7 million for 12 months ending December 31, 2024, and \$17.3 million
9 for 12 months ending December 31, 2025. Similar to the 2022 actual expenditures,
10 these projections include outage restoration, including conversion of failed mercury
11 vapor luminaires to LED for both streetlight and OPLs, post replacement, new
12 business, and capital support staff. As previously discussed, Community Lighting
13 launched its underground cable replacement program in 2022 which is also
14 included in Exhibit A-12, Schedule B5.5 line 4 with projected spend of \$1.5 million
15 for 2023, \$1.1 million for 12 months ending December 31, 2024, and \$1.7 million
16 for 12 months ending December 31, 2025.

17

18 **LED Luminaire Selection Methodology Specific to HID to LED Conversions**

19 **Q42. Can you provide an overview on HID to LED conversions and DTE's LED**
20 **selection methodology for such conversions?**

21 A42. In Case No. U-21297, we described two distinct scenarios in which the Company
22 recommends installation of specific LED luminaires, and our LED selection
23 methodology for both. The first scenario pertains to new lighting installations. A
24 new installation for purpose of this discussion, is generally defined as installing
25 poles, wiring, and luminaires where they did not exist previously (i.e., a

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1 municipality has constructed a roundabout and engaged DTE to provide a lighting
2 design for the new roundabout). In this scenario, all new lighting installations will
3 be evaluated in accordance with ANSI/IES RP-8 standards.

4
5 The second scenario, which results in the majority of LEDs being installed, pertains
6 to HID to LED conversions on pre-existing lighting systems. Most lighting systems
7 that the Company owns, operates, and maintains, were installed decades ago, and
8 pre-date current lighting standards that the Company adheres to today when making
9 recommendations for new lighting installations. As stated in my rebuttal testimony
10 in Case No. U-21297, “[t]he Company understands that pre-existing streetlighting
11 infrastructure may not meet ANSI/IES RP-8 standards, and that it would be
12 impractical and costly for municipalities to do so.”³ The reason it would be
13 impractical and costly to conform to current ANSI/IES RP8 lighting standards for
14 pre-existing lighting systems is that these older municipal lighting systems would
15 need extensive reconfiguration inclusive of work such as pole relocations and
16 rewiring of the overhead and underground system cable. Therefore, our objective
17 during conversion work is to restore the equivalent “out of the box” initial output
18 of the HID luminaire with an LED luminaire.

19
20 Under either scenario, the customer has the choice to deviate from the Company’s
21 recommended lighting design.

22

23 **Q43. Could you please summarize the order in Case No. U-21297 with respect to the**
24 **Company’s LED selection methodology?**

³ Bellini Rebuttal Testimony, Case No. U-21297, pg. 12, lines 21-23

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1 A43. The MPSC Commission in their order in Case No. U-21297 disallowed
2 approximately \$5.8M of LED plant from the Company's historical books,
3 determining that the Company had overspent on LED conversions, in part based on
4 the wattage of the luminaires it selected as compared to a crossover chart from the
5 Company's primary LED lighting vendor, Leotek.

6

7 Specifically, on page 137 of the order, the Commission states "...DTE Electric does
8 not deny that its lamp choices exceed what Leotek recommends as a high-level
9 choice. The ALJ further found that "DTE has not established that it has any
10 meaningful discussion⁴ with customers currently regarding the choice of lighting"
11 and that "since DTE does not conduct any analysis of the appropriate lighting for
12 the roadway at issue, it is difficult to credit that DTE meaningfully consults with its
13 municipal customers." Absent convincing evidence to the contrary, the ALJ found
14 that the crossover recommendations are reasonable."

15

16 **Q44. What significant developments have occurred since the order in Case No. U-**
17 **21297?**

18 A44. Specifically, Leotek no longer supports their crossover chart and has removed them
19 from their Company's website. This Leotek crossover chart was one of the primary
20 reasons for the MAUI adopted proposal of DTE's historical LED plant reductions
21 as reflected in witness Bunch's workpaper prepared in Case No. U-21297, included
22 here as Exhibit A-25 Schedule O4 titled "WP Calculation of \$5.8M Disallowance
23 by MI-MAUI in U-21297."

⁴ U-21297 Proposal For Decision, p. 340.

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1 **Q45. Are you recommending that the MPSC Commission revisit the reasoning that**
2 **resulted in the disallowance of the LED plant-in-service in Case No. U-21297?**

3 A45. Yes. Both DTE and MAUI drew distinctly different conclusions from the Leotek
4 crossover chart presented in Case No. U-21297. Given that the crossover chart is
5 no longer supported by Leotek, which was the primary evidence used to determine
6 the excessive spend in LEDs during conversions, it would be prudent to revisit the
7 methodology employed by DTE in its HID to LED conversions on pre-existing
8 streetlighting systems.

9
10 In the instant case, DTE sought the opinions of two lighting industry experts
11 (discussed later in my testimony) to review and provide independent opinions as to
12 the reasonableness and prudence of DTE's LED selection methodology as it relates
13 to conversions. Given the technical complexity of this topic and the limited time
14 available to discuss this issue in the context of a rate case, the Company would be
15 amenable to a Staff facilitated technical workshop inclusive of Leotek's
16 engineering team, DTE, expert consultants, and MI-MAUI with the intent of
17 evaluating appropriate HID to LED equivalent conversions employed by DTE and
18 determine whether or not DTE unnecessarily installed more expensive LEDs during
19 conversions. It would also be prudent to directly engage with Leotek and the
20 preparer of this chart in order to assess whether or not DTE erred in selecting
21 luminaires that deviated from this chart which is no longer supported by Leotek.

22
23 **Q46. Is DTE presenting additional evidence supporting its' selection methodology**
24 **specific to HID to LED conversion projects on pre-existing lighting systems?**

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1 A46. DTE has sought the independent review and opinions of two lighting industry
2 experts, Dr. Ronald Gibbons, PH.D., FIES, currently the Director of the Center for
3 Infrastructure Based Safety Systems (CIBSS) at the Virginia Tech Transportation
4 Institute (VTTI)⁵, and Donald McLean, PLEng (Founder and Senior Partner, DMD
5 Consulting Engineers, Ltd)⁶ as to the appropriateness of DTE's LED selection
6 methodologies pertaining to HID to LED conversions. Both experts were asked to
7 review and opine on DTE's lighting study which recommended 58W and 136W
8 LED selections when converting 100W HPS and 250W HPS fixtures, respectively,
9 as these HPS fixture types are the most commonly converted municipal fixtures.

10

11 **Q47. Please summarize Don McLean's findings and overall conclusion with respect**
12 **to DTE's LED selection process when converting HID's.**

13 A47. Mr. McLean's key points from his conclusion detailed in his report (Exhibit A-25,
14 Schedule O5, page 15) are quoted below:

- 15 • "From a comparison standpoint, matching published lumens from luminaire
16 to luminaire is not always the best method. It is more important to assess
17 lighting levels on the roadway, which was undertaken by DTE."
- 18 • "DTE reviewed both roadway lighting levels on and off the roadway
19 defining lighting Luminance and Illuminance metrics in the analysis,
20 including spill lighting. In our opinion, what DTE have provided is
21 reasonable for an HPS to LED conversion given they have focused on
22 calculated lighting levels on the roadway vs simply using lumen values."

⁵ U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, p12 - 28

⁶ U-21534 Exhibit A-25 Schedule O8_Don McLean_Curriculum Vitae

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- 1 • “DTE’s use of multiple roadway types and averaging the results of these
- 2 roadways is a reasonable methodology to use in comparing luminaires and
- 3 as a luminaire selection guide in large scale retrofit HPS-LED conversions.”
- 4 • “Based on the criteria and approach defined by DTE, DMD is in agreement
- 5 with the conversion methods and LED luminaires chosen to replace the
- 6 incumbent 100W and 250W HPS luminaires.”

7

8 **Q48. Please also summarize Dr. Gibbons’ findings and overall conclusion with**
9 **respect to DTE’s LED selection process when converting HID’s.**

10 A48. Dr. Gibbons’ key points from his conclusion detailed in his report (Exhibit A-25,
11 Schedule O9, page 11) are quoted below:

- 12 • “The approach DTE Energy used for the selection of luminaires is valid and
- 13 aligns with the state of the art in the industry.”
- 14 • “The luminaires selected by DTE energy were appropriate for the template
- 15 roadways considered in their analysis.”
- 16 • “The appropriate luminaires for intersection evaluations selected through
- 17 analysis are Leotek 136W and the Leotek 58W for the 250Watt HPS and
- 18 for the 100 Watt HPS respectively.”

19

20 **Q49. Please identify and define the primary LED lighting criteria evaluated by**
21 **DTE when selecting an appropriate LED replacement of an HID light.**

22 A49. Though there are several criteria used in evaluating lighting options, roadway
23 illuminance and luminance are weighted more heavily than other criteria such as
24 glare, light trespass, etc.

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1 The Texas Department of Transportation (TxDOT) provides the following simple
2 definitions for roadway illuminance and luminance:⁷

- 3 • Roadway Illuminance: Measurement of the amount of light that hits the
4 pavement surface.
- 5 • Roadway Luminance: Measurement of the reflected light from the
6 pavement surface that is visible to the motorist's eye.

7

8 TxDOT states that “[t]he level and uniformity of illuminance or luminance along a
9 highway depends on several factors, including the lumen output of the light source,
10 luminaire distribution, mounting height, luminaire position, pavement reflectance,
11 and pole spacing and arrangement.”

12

13 This weighting criteria is consistent in both the manner in which DTE assessed
14 proper LED selections when converting municipal HID lighting projects and also
15 as evaluated by both industry experts discussed in their detailed findings below.

16

17 **Q50. Please briefly explain the parameters of the reviews conducted by both**
18 **experts.**

19 A50. Both Don McLean and Dr. Gibbons conducted an independent review based on
20 information sourced and used by DTE in its' own analysis (“WP-RAB – Work
21 Paper A – Agi 32 Simulation Files_100W HPS” through “WP-RAB – Work Paper
22 Q – IES Photometric Files_LED”) in selecting LEDs used in HID to LED
23 conversion projects.

⁷ Highway Illumination Manual: Illumination Levels (txdot.gov) available at
https://onlinemanuals.txdot.gov/TxDOTOnlineManuals/TxDOTManuals/hwi/illumination_levels.htm#i1024407

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1 Both reviews were specific to DTE's most commonly converted fixtures, the 100W
2 and 250W HPS fixtures. Both compared new (or "out of the box") LED luminaires
3 to new HPS luminaires.

4

5 **Q51. Please highlight Mr. McLean's review process and specific conclusions from**
6 **his report (Exhibit A-25, Schedule O8) on DTE's selections of the 58W and**
7 **136W to replace 100W and 250W HPS fixtures, respectively.**

8 A51. The key findings are noted below in various quoted excerpts from Mr. McLean's
9 report (Exhibit A-25 O5 "Don McLean DTE HID-LED Selection Methodology
10 Opinion Letter"):

11

12 100W HPS Replacement Evaluation

13 "Revised Rdwy Performance Summary.xlsx (Exhibit A-25 O7_DMD_Rdwy
14 Performance Summary) contains Target Roadway lighting calculation summaries
15 for Roadways 100A through 100G as provided in "Workpaper G - Roadway
16 Typical Master Table 02 01 18." These 7 roadways pertain to 100W HPS
17 replacements only. The calculation summaries contain roadway Luminance and
18 Illuminance metrics for the existing 100W HPS and the 4 LED luminaires DTE
19 used in the conversion analysis."

20

21 "Revised Rdwy Performance Summary.xlsx" then takes the calculation summaries
22 for each of the 4 LED models considered in the analysis and compares the average
23 values for Luminance and Illuminance to the average values for the HPS luminaire
24 as HPS is taken as the baseline."

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1 250W HPS Replacement Evaluation

2 “Revised Rdwy Performance Summary.xlsx” contains Roadway lighting
3 calculation summaries for Roadways 250A, 250B, 250C AND 250F as they are
4 described in the Exhibit G - Roadway Typical Master Table 02 01 18 (Rate Case)
5 (Master Tables). These roadways pertain to 250W HPS replacements only. The
6 calculation summaries contain roadway Luminance and Illuminance metrics for the
7 existing 250W HPS and the 4 LED luminaires used in the analysis.”

8

9 “Revised Rdwy Performance Summary.xlsx” then takes the calculation summaries
10 for each of the 4 LED models considered in the analysis and compares the average
11 values for Luminance and Illuminance to the Average values for the HPS luminaire
12 as HPS is taken as the baseline.”

13

14 58W LED Results Summary

15 “The light levels produced by the 58W LED Luminaire showed an increase in
16 Average Illuminance. The 58W fixture failed to meet spill light targets at
17 surrounding property lines with a 51.2% increase compared to the 100W HPS
18 baseline. While the 37W, 30W and 27W fixtures meet spill lighting targets within
19 a reasonable tolerance, the 58W luminaire is the only fixture that was able to
20 maintain the minimum Average Illuminance of the HPS baseline.”

21

22 136W LED Results Summary

23 “The 136W luminaire had the highest Average Illuminance out of the 4 LEDs at
24 only 3.5% below the target HPS baseline levels, which we would deem to be within
25 a reasonable level of tolerance. The 136W LED luminaire was also the only

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1 luminaire to maintain baseline spill light levels, with a 27.3% reduction in max spill
2 light levels at property frontages compared to the 250W HPS baseline.”

3

4 **Q52. Please highlight Dr. Gibbons’ review process and specific conclusions from his**
5 **report (Exhibit A-25, Schedule O9) on DTE’s selections of the 58W and 136W**
6 **to replace 100W and 250W HPS fixtures.**

7 A52. In Dr. Gibbons review of various simulations, he “verified the parameters placed
8 in the simulation including luminaire type, location, and tilt angle” and then
9 “calculated the lighting levels within each model.” Using this data, Dr. Gibbons
10 then “compared the calculated results to the incumbent HPS technology where the
11 roadway illuminance, luminance, glare, sidewalk illuminance and light trespass
12 values were reviewed. In the analysis, the result criteria were established that the
13 luminaire had to increase the luminance and illuminance on the roadway with the
14 desire to increase the sidewalk illuminance, while reducing glare and light
15 trespass.”⁸ The key findings are noted below in various quoted excerpts from Dr.
16 Gibbons report (“Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response
17 Document & CV):”

18

19 100W HPS & 250W HPS Replacement Evaluation

20 “In the review of the DTE methodology, I [Dr. Gibbons] opened the AGI32 Simulation
21 packages for the 100 Watt HPS replacement comparisons and the 250 Watt HPS
22 comparisons. In all there were 8 comparison templates for 100 Watt selection process
23 and 4 templates for the 250 Watt comparisons. In each of the simulations, I verified the
24 parameters placed in the simulation including luminaire type, location, and tilt angle. I

⁸ U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, p3-4

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1 then calculated the lighting levels within each model. Using this data, I compared the
2 calculated results to the incumbent HPS technology where the roadway illuminance,
3 luminance, glare, sidewalk illuminance and light trespass values were reviewed. In the
4 analysis, the result criteria were established that the luminaire had to increase the
5 luminance and the illuminance on the roadway with the desire to increase the sidewalk
6 illuminance while reducing glare and the light trespass.”

7
8 58W & 136W LED Results Summary

9 “Based on this analysis, I [Dr. Gibbons] would recommend the Leotek 58W to replace
10 the 100W HPS and the Leotek 136W to replace the 250W HPS.”

11
12 **LED Comparison Matrices Summarizing Dr. Gibbons findings⁹**

13
**Table 4: Study Results of 100W HPS to LED
Conversion for Continuous Lighting on Straight Roadway**

	LED 58W	LED 37W	LED 30W	LED 27W
Roadway Template A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template B	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template D	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template E	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template F	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template G	Fully Meets	Fully Meets	Fully Meets	Does not Meet
Roadway Descriptions				
Roadway Template A	2013 Application Specification (one row, near side, 2-lanes, 24' road width, 28.5' MH, 2' setback, 150' pole-to-pole spacing)			
Roadway Template B	Greenbush Rd, Wayne			
Roadway Template C	Same as Roadway Template B with short arm application change			
Roadway Template D	15899 E. Eleven Mile Rd, Roseville			
Roadway Template E	16461 E. Eleven Mile Rd, Roseville			
Roadway Template F	321 E. Granet Ave, Hazel Park			
Roadway Template G	Same as Roadway Template F with short arm application change			

⁹ Summary of results prepared by DTE based on Dr. Gibbons analysis from tables presented in U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, pp 4-5, 11

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1

**Table 5: Study Results of 100W HPS to LED
Conversion for Local/Local Intersection**

	LED 58W	LED 37W	LED 30W	LED 27W
Local/Local A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local B	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local A	S. Linville Ave and Hazelwood St, Westland			
Local/Local B	Griffith Ave and Wiltshire Rd, Berkley			
Local/Local C	Pine St and 8th St, Port Huron			

2

**Table 6: Study Results of 250W HPS to LED
Conversion for Continuous Lighting on Straight Roadway**

	LED 136W	LED 111W	LED 89W	LED 72W
Roadway Template A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template B	Does not Meet	Fully Meets	Does not Meet	Does not Meet
Roadway Template C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template F	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template A	2013 Application Specification (two rows, opposite, 4-lanes, 48' road width, 30' MH, 2' setback, 180' pole-to-pole spacing)			
Roadway Template B	Avondale St and Carlson St, Westland			
Roadway Template C	Same as Roadway Template B with short arm application change			
Roadway Template F	Ryan Rd between Mckinley Ave and Frazho Rd, Warren			

3

**Table 7: Study Results of 250W HPS to LED
Conversion for Local/Local Intersection**

	LED 136W	LED 111W	LED 89W	LED 72W
Collector/Collector A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Collector/Collector B	Fully Meets	Fully Meets	Does not Meet	Does not Meet
Collector/Collector C	Does not Meet	Does not Meet	Does not Meet	Does not Meet
Collector/Collector A	Sheldon Rd and Saltz Rd, Canton			
Collector/Collector B	Avondale Rd and Wildwood Ave, Westland			
Collector/Collector C	13th St and Court St, Port Huron			

4

5 **Q53. Please summarize DTE's four recommendations to the MPSC Commission**
6 **based on the new evidence provided in the instant case.**

7 A53. Recommendation 1: Based on both experts' independent analysis and conclusions
8 as to the appropriateness of our LED selections for conversions, the Company

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1 believes it would prudent to continue utilizing 58W and 136W Leotek LEDs when
2 converting 100W and 250W HPS luminaires, rather than being limited to the
3 choices based solely on Leotek's crossover chart, which is no longer supported by
4 the Company.

5

6 Recommendation 2: In addressing the ALJ's comments provided in the PFD in
7 Case No. U-21297 (PFD, p. 340) that "DTE has not established that it has any
8 meaningful discussion with customers currently regarding the choice of lighting,"
9 the Company proposes to memorialize our LED recommendations (noted in the
10 preceding paragraph) to the customer in their contract prior to signing, and
11 explicitly informing the customer in the contract and during discussions that the
12 customer has the choice to select another LED at their discretion and confirmed in
13 the municipal conversion agreement.

14

15 Recommendation 3: If the Commission deems it necessary, the Company would
16 be amenable to a Staff facilitated technical workshop inclusive of Leotek's
17 engineering team, DTE, outside consultants, and MI-MAUI with the intent of
18 evaluating appropriate HID to LED equivalent conversions employed by DTE and
19 also determining whether or not DTE unnecessarily installed more expensive LEDs
20 during conversions.

21

22 Recommendation 4: Based on the new evidence presented by the Company in the
23 instant case, we believe it may be appropriate to revisit the decision to disallow the
24 \$5.8M in LED gross plant as ordered in Case No. U-21297.

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1 **Community Lighting Rate Design**

2 **Q54. What does Exhibit A-16, Schedule F3 show?**

3 A54. This exhibit shows the present and proposed rate design and corresponding
4 revenues by rate schedule, based on the billing determinants for the 12 months
5 ending December 31, 2025. The exhibit details the forecasted billing determinants
6 as well as the resulting present and proposed rates and revenues. The various billing
7 components are listed in column (a), and the respective billing determinants,
8 including units of measure, are listed in column (b). The forecasted billing
9 determinants were developed based on historical data and relationships, as well as
10 known and measurable changes, and are consistent with the sales forecast as
11 presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E1, Other
12 class sales. The existing luminaire and energy rates, both non-capacity energy and
13 capacity energy, as approved in the Order dated December 1, 2023, in Case No. U-
14 21297 are in columns (c), (d) and (e), and are used to calculate the present revenues
15 in column (f). The luminaire rates proposed in this proceeding based upon the
16 lighting cost of service (as discussed in detail below) are in column (g), the
17 proposed non-capacity energy rates are in column (h), the proposed capacity energy
18 rates are in column (i) and the resulting revenues from the new lighting cost of
19 service are in column (j).

20

21 **Q55. How were DTE Electric's present Municipal Street Lighting and Outdoor**
22 **Protective Lighting charges determined?**

23 A55. The lighting rates approved in MPSC Case No. U-21297 reflect a monthly energy
24 charge, both non-capacity energy and capacity energy, and a luminaire charge. The
25 monthly energy charge was determined by applying the energy rates, both in

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1 cent/kWh, to the calculated consumption values of the various lighting technology
2 lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge is a fixed
3 monthly amount applied to each luminaire dependent on the technology utilized,
4 the lamp size or wattage, the lighting provision and whether it is served from
5 underground or overhead. The total (energy and luminaire) monthly lighting
6 charges that were calculated in Case No. U-21297 do not fully represent true cost
7 of service rates by technology type (within the lighting rate class). In Case No. U-
8 21297, the lighting rates were gradually moved towards cost of service, with the
9 total movement capped to minimize the impact on any individual customer.

10

11 **Q56. What is the allocation methodology for production and distribution revenue**
12 **requirements to the various lighting rate schedules that you are supporting in**
13 **this case?**

14 A56. The functionalized production (Exhibit A-16, Schedule F1.1) and distribution
15 (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by
16 Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2)
17 were fully allocated to each of those rate schedules within the lighting rate model.
18 The proposed luminaire, distribution, and energy charges (both capacity and non-
19 capacity) within each of the rate schedules were designed to meet the production
20 and distribution revenue requirement for each rate schedule shown in these exhibits.
21 Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the
22 production revenue requirement for each rate class is capacity and non-capacity
23 related, was used to allocate the production revenue requirement between the
24 capacity and non-capacity energy charges. The E1 and D9 Rate Schedule energy
25 charges, both capacity and non-capacity, were developed based upon the total

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1 production revenue requirement prepared by Witness Maroun for the E1 and D9
2 Rate Schedules.

3

4 **Rate Schedule E1**

5 **Q57. How were the proposed E1 Rate Schedule luminaire charges determined?**

6 A57. The Company determined the new luminaire service cost structures listed in the E1
7 Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3 by
8 reviewing and allocating the specific cost of service components to the type of
9 service, underground or overhead, and then further allocating them to the individual
10 lighting technologies. There were no changes in the methodology for the allocation
11 of non-production O&M costs or capital-related costs to luminaire charges
12 proposed in this proceeding.

13

14 **Q58. How was O&M allocated to the proposed E1 Rate Schedule luminaire charges**
15 **in the lighting model?**

16 A58. Total Distribution O&M expense reflected in the E1 Rate Schedule luminaire
17 charge is \$9.5 million, based upon the Company's cost of service model sponsored
18 by Witness Maroun. This distribution O&M expense is comprised \$3.2 million
19 directly assigned to lighting and recorded in account 596 (Street Lights & OPL),
20 \$3.5 million allocated to lighting from various distribution operation and
21 distribution maintenance accounts, \$1.3 million from various customer
22 service/sales accounts allocated to E1 Rate Schedule lighting and \$1.5 million of
23 total A&G expense. Based upon the underlying labor costs within account 596 and
24 the various distribution operation, distribution maintenance and customer service
25 accounts allocated to E1 Rate Schedule lighting, approximately 41%, or \$0.6

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1 million, of A&G expense was directly allocated to E1 Option I Rate Schedule
2 lighting and the balance was allocated to the various distribution O&M accounts
3 within the E1 Rate Schedule.

4
5 The total customer service and distribution O&M expense allocated to lighting,
6 including A&G allocated to these accounts, was further allocated to the various E1
7 Rate Schedule luminaire/distribution charges based upon the system wattage of the
8 luminaires and lamps. With the exception of post inspection, night patrols and post
9 painting, all O&M (\$3.2 million) and A&G (\$0.6 million) directly assigned to
10 lighting was spread equally across all luminaires. The O&M associated with post
11 inspection and post painting was spread equally to all underground fed luminaires.

12

13 **Q59. How was depreciation expense allocated to the proposed E1 Option I Rate**
14 **Schedule luminaire charges in the lighting model?**

15 A59. The total depreciation expense reflected in the E1 Option I Rate Schedule luminaire
16 charges, as established in the Company's cost of service model supported by
17 Witness Maroun, is \$27.6 million. This reflects \$20.3 million depreciation for the
18 directly assigned lighting asset accounts, \$3.1 million for the distribution asset
19 accounts allocated to lighting, and the balance associated with general and
20 intangible plant accounts allocated to lighting.

21

22 The depreciation expense for overhead subaccount 373.01 (street lighting and
23 signal systems - overhead) was allocated directly to overhead fed luminaires, and
24 depreciation expense for underground subaccount 373.02 (street lighting and signal
25 systems – underground) was allocated directly to underground fed luminaires. The

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1 depreciation expense for overhead subaccount 373.03 (Street Lighting wire - OH)
2 was allocated to all overhead luminaires equally. The depreciation expense for
3 underground subaccount 373.04 (Street Lighting Wire/Cable - Underground) was
4 allocated to all underground-fed luminaires equally.

5
6 The depreciation expense for both the overhead and underground luminaire
7 subaccounts (LED Overhead, LED Underground, and HID Overhead, HID
8 Underground) was allocated to the respective overhead and underground
9 luminaires based upon lighting technology, wattage and underlying original
10 investment. For instance, all underground-fed mercury vapor luminaires received
11 an allocation of depreciation expense from subaccount 373.05 (Street Lighting
12 Luminaires – HID Underground) based upon the luminaire type's investment and
13 underlying mercury vapor luminaire useful life.

14
15 The depreciation expense that was allocated to lighting from distribution was
16 allocated to all underground and overhead lighting based upon each luminaire
17 type's system wattage -- the best representation of each lighting type's usage of the
18 distribution system.

19

20 **Q60. How was the revenue requirement for other taxes, return on investment and**
21 **income tax allocated to the proposed E1 Option I Rate Schedule luminaire**
22 **charges?**

23 A60. All other components were allocated to the various luminaire types in a manner
24 similar to that employed for the related underlying depreciation expense. For the

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1 directly assigned street lighting asset subaccounts, other taxes, return on investment
2 and income tax followed the allocation of net plant to each of the lighting types.

3

4 **Q61. Do you believe the proposed allocation of costs reflected in the various E1**
5 **Option I Rate Schedule luminaire charges is reasonable?**

6 A61. Yes. The methodology utilized in the lighting model to allocate each of the
7 individual cost of service components discretely, rather than in total, more
8 accurately reflects the cost to provide lighting service to underground and overhead
9 assets as well as the various lighting technologies. The use of the eight separate
10 asset subaccounts for allocation of the capital-related costs results in more accurate
11 rate setting based upon both how the lights are fed as well as the lighting
12 technology, wattage and luminaire investment.

13

14 **Q62. How were the E1 Option II Rate Schedule charges developed?**

15 A62. The E1 Option II Rate Schedule charges were developed based upon a share of the
16 production revenue requirement allocated by Witness Maroun in the Company's
17 cost of service model to the E1 Rate Schedule, a share of the distribution and
18 customer service revenue requirements allocated by Witness Maroun in the
19 Company's cost of service model to the E1 Rate Schedule and a small allocation of
20 the O&M expense directly assigned to the E1 Rate Schedule from Account 596.
21 The allocations of revenue requirement from production, distribution and customer
22 service to the E1 Option II Rate Schedule were accomplished on a per kWh basis
23 across all E1 Option II rates. The proposed rates for the E1 Option II Rate Schedule
24 are displayed in a luminaire charge, similar to that for Rate Schedule E1 Option I,
25 and energy charges, both capacity and non-capacity, in a cent/kWh format.

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1 **Q63. How were the E1 Option III Rate Schedule charges developed?**

2 A63. The E1 Option III Rate Schedule charges were developed based upon a share of the
3 total production revenue requirement allocated by Witness Maroun in the
4 Company's cost of service model to the E1 Rate Schedule, a share of the total
5 distribution revenue requirement allocated by Witness Maroun in the Company's
6 cost of service model to the E1 Rate Schedule and a share of the customer service
7 revenue requirement allocated by Witness Maroun in the Company's cost of service
8 model to the E1 Rate Schedule. The allocations of revenue requirement from
9 production, distribution and customer service to the E1 Option III Rate Schedule
10 were performed on an equal energy basis across all E1 Option III rates. The
11 proposed E1 Option III Rate Schedule distribution and energy charges, both
12 capacity and non-capacity, are displayed in a cent per kWh format, allowing for a
13 transparent comparison of lighting costs for the various luminaire system wattages
14 and the various lighting technologies.

15

16 **Q64. How does your proposed cost allocation methodology impact the present rates**
17 **for the E1 Rate Schedule?**

18 A64. The cost allocation methodology described above and employed in the lighting
19 model reflects a collective revenue deficiency for the E1 Rate Schedule options.

20

21 **Q65. What is your proposal regarding rate design in this proceeding for Rate**
22 **Schedule E1 Option I rates?**

23 A65. I have proposed a continuation of the gradual move towards rates which are entirely
24 based upon cost of service for the lighting class. Consensus on this methodology
25 was reached in the lighting collaborative ordered in Case No. U-17767 and

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1 beginning with rate Case No. U-18014, the Rate Schedule E1 Option I lighting rates
2 are being gradually moved to rates which are entirely based upon cost of service.

3

4 **Q66. How were the Rate Schedule E1 Option I proposed rates developed in this**
5 **proceeding?**

6 A66. The proposed Rate Schedule E1 Option I lighting rates were designed with two
7 goals in mind; (1) continue the gradual move to rates which are entirely cost based
8 and (2) minimize the impact of the proposed lighting rates on the monthly lighting
9 bill for any municipality. Using the lighting rate model, the first step towards
10 achievement of these goals was to limit the overall increase on any municipality
11 and/or total lighting rate to 1.5 times the proposed average increase in revenue
12 requirement. The second step of the process was to allocate the remaining revenue
13 deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all the
14 remaining lights.

15

16 **Rate Schedule D9**

17 **Q67. How were the proposed rates for the D9 Rate Schedule determined?**

18 A67. The proposed luminaire rates for the D9 Rate Schedule for both commercial and
19 residential OPL service were developed based upon the allocated and directly
20 assigned distribution costs supported by Witness Maroun in the Company's cost of
21 service model. The luminaire rate design methodology employed in the lighting
22 model for the D9 Rate Schedule mirrors the methodology employed for the E1 Rate
23 Schedule with all allocated distribution costs assigned to luminaire charges based
24 upon energy consumption and the directly assigned costs allocated based upon the
25 underlying individual cost of service components. As I discussed earlier, the

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1 proposed energy charges, both capacity and non-capacity, for the D9 Rate Schedule
2 for both commercial and residential OPL service were developed collectively with
3 the E1 Rate Schedule energy charges.

4

5 **Q68. Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-**
6 **based?**

7 A68. No. The proposed rates for Rate Schedule D9 required the use of the same two-
8 step methodology to gradually achieve cost-based intra-class rates that was
9 employed for the E1 Option I Rate Schedule.

10

11 **Rate Schedule E2**

12 **Q69. How were the proposed Rate Schedule E2 charges determined?**

13 A69. The Rate Schedule E2 charges were developed based upon the production, both
14 capacity and non-capacity, and distribution revenue requirements allocated to Rate
15 Schedule E2 customers by Witness Maroun in the Company's cost of service
16 model. Each of the revenue requirement amounts were divided by the total
17 forecasted energy for the projected test period to arrive at a distribution rate, a non-
18 capacity energy rate and a capacity energy rate in cents/kWh.

19

20 **Q70. How has Witness Maroun's presentation of the revenue deficiency for**
21 **production presented in this case impacted your rate design?**

22 A70. To allocate the targets to the lighting tariff energy charges, both capacity and non-
23 capacity, in the cost of service-based rate presentation, I have allocated the revenue
24 deficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the total
25 D9 deficiency, and total E1 deficiency Rate Schedules to those energy rates in total.

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1 **Q71. Will you please describe Exhibit A-16, Schedule F8?**

2 A71. This exhibit contains the proposed tariff sheet changes which result from the pricing
3 changes described above.

4

5 **Q72. Does this complete your direct testimony?**

6 A72. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

ROBERT A. BELLINI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ROBERT A. BELLINI

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

3 A1. My name is Robert A. Bellini (he/him/his). My business address is 8001 Haggerty,
4 Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE
5 Electric or Company) as Manager of Community Lighting.

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my rebuttal is to rebut the following intervenor positions:

14

15 Michigan Municipal Association for Utility Issues (MI-MAUI), Witness Bunch

16 1) Proposal that CIAC be discontinued for HID-LED group/project
17 conversions

18 2) Proposal to create a bill credit scheme designed to issue future credits to
19 early LED adopters

20 3) Proposal to adjust the E1 streetlighting sales forecast by 3,308,045 kwh,
21 equivalent to 4.06% of unadjusted forecast

22 4) Proposal that the Company be disallowed recovery of its post painting and
23 inspections costs

24 5) Proposal to disallow spending on the Company's underground capital cable
25 replacement program

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- 1 6) Proposal to include streetlighting capital and distribution O&M plans in its
2 Distribution Grid Plan
- 3 7) Recommended creation of additional reports providing taxonomy of root
4 cause outages, causes of delays in restoration, cost breakdowns, and other
5 data
- 6 8) Proposed cumulative disallowance of either \$7,705,567 or \$5,833,539
7 based on the claim that the Company is unreasonably spending on
8 excessively bright LEDs
- 9 9) Recommendation that the Company be ordered to implement full cost-of-
10 service rates

11

12 City of Ann Arbor, Witnesses Naheedy & Stults

- 13 10) Assertion that Company restoration performance continues to be poor
- 14 11) Assertion that Ann Arbor stocking a 58W LED with a lower color
15 temperature as “special order material” is unreasonable
- 16 12) Assertion that Ann Arbor was financially disadvantaged as a result of HPS
17 now being replaced with equivalent LEDs upon their failure, noting that
18 they’d have paid nothing if they waited for each HPS to fail
- 19 13) Proposal that Ann Arbor should receive a bill credit in recognition of the
20 City paying for the conversion of other customers making the transition
21 from HID to LED fixtures

22

23 **Recommendations**

24 **Q4. Please summarize your conclusions, recommendations, and Company**
25 **positions to the Commission.**

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1 A4. My summary of conclusions, recommendations, and Company positions are
2 outlined below:

3 MI-MAUI Proposals/Assertions

4 1) The Commission should continue to reject (as it has in the past) MI-
5 MAUI's recommendation to discontinue CIAC charges for LED upgrades.
6 The existing CIAC approach, approved by the Commission for converting
7 company-owned mercury vapor (MV) lights to LEDs, remains valid. This
8 method, which includes the now outdated high-pressure sodium (HPS)
9 lights, should continue in line with the established practice for mercury
10 vapor (MV) light replacements, as both MV and HPS are categorized as
11 HID.

12
13 2) MI-MAUI's recommendation to create a bill credit scheme designed to
14 refund CIAC to customers that converted lighting systems to LEDs should
15 be dismissed. Refunding past years of previously customer funded CIAC
16 is unwarranted, inconsistent with previously Commission-approved policy,
17 and would have an adverse effect on all municipal streetlight customer rates
18 given that the LEDs now represent almost 70% of all company-owned
19 municipal streetlights.

20
21 3) The Company agrees with MI-MAUI's proposal to adjust the sales forecast
22 based on the 2023 night patrol outage results for the incremental difference
23 of 0.81% (4.06% based on 2023 night patrol outages less 3.25% ordered in
24 U-21297). However, as the night patrol program evolves, it will target
25 communities with higher outage percentages. Therefore, annual results will

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1 become less of a proxy for system-wide outages. The Company
2 recommends the Commission order it to work with Staff and MI-MAUI to
3 establish a methodology that provides for a long-term, sustainable approach
4 to approximate system wide outages.

5

6 4) The Company recommends that the Commission deny MI-MAUI's
7 proposed disallowance for post painting and post inspections or conversely,
8 approve recovery over the same time period for the Company's under-
9 recovery of outage maintenance costs.

10

11 5) The Commission should reject MI-MAUI's proposal to disallow the
12 Company's recovery of its underground capital cable replacement program.
13 Witness Bunch's claim that the Company has not provided reliability or cost
14 data to justify this program is incorrect. All of the underground replacement
15 projects completed since program inception were data driven and resulted
16 in avoidance of future outage events.

17

18 6) The Commission should reject the proposal that Community Lighting
19 capital investment costs for its underground cable replacement program and
20 other O&M costs be included as part of DTE's Distribution Grid Plan
21 (DGP). The focus of the DGP is specific to distribution investments, and
22 were never intended to encompass Community Lighting infrastructure.
23 Community Lighting's assets/rate base, system of operations, and
24 investments are distinctly different than that of DTE's distribution system
25 and are appropriately excluded from the DGP.

26

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- 1 7) The Commission should reject MI-MAUI's proposal requiring the
2 Company to create a variety of new reports with criteria ranging from a
3 taxonomy of root cause outages, causes of delays in restoration, cost
4 breakdowns, and other data for two reasons. First, the proposal is based on
5 a false premise that the Company's outage performance continues to
6 deteriorate, which it has not. Second, Witness Bunch incorrectly overstates
7 the capabilities of the Company's new outage management system,
8 Kloudgin. I recommend the Commission order the Company, Staff, and
9 MI-MAUI work together to review the Company's system reporting
10 capabilities.
- 11
- 12 8) MI-MAUI's recommended cumulative disallowance pertaining to HID-
13 LED conversions of either \$7,705,567 or \$5,833,539 based on its claim that
14 the Company unreasonably spent on excessively bright LEDs should be
15 dismissed for two reasons. First, Witness Bunch's only basis for asserting
16 the Company selected over lit LEDs and in calculating this disallowance,
17 was a vendor (Leotek) LED crossover chart that has since been disavowed
18 by the vendor and is no longer supported or available. Second, the Company
19 engaged two lighting industry experts the purpose of which was to analyze
20 and opine on the Company's LED selection methodology when replacing
21 existing customer HID lights through project conversions. Both industry
22 experts independently concluded that DTE's methodology for selecting
23 LEDs was reasonable and appropriate.

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1 9) Similar to its position during Case No. U-21297, the Company does not take
2 a position on MI-MAUI's recommendation to order the Company to
3 implement full-cost-of service rates, but instead provide information to the
4 Commission in making a prudent decision on whether to continue using the
5 current design methodology while considering the interests of all rate
6 payers.

7

8 Ann Arbor Proposals/Assertions

9 10) Witness Naheedy incorrectly claims that the Company's outage restoration
10 performance continues to be poor and bases his conclusion on his
11 predecessor's testimony presented during Case No. U-20836 two years ago
12 which stated that DTE's outage rate was 26%. To the contrary, the
13 Company has conducted 8 night patrols that canvassed all of Ann Arbor's
14 company-owned municipal streetlights between 2020 – 2023. The outage
15 results from these 8 patrols ranged from 2% to 6%.

16

17 11) Ann Arbor incorrectly concludes that having to stock a 58W LED with a
18 lower color temperature as "special order material (SOM)" is unreasonable.
19 The Company's standard stock 58W LED fixture is 4000 CCT. ANSI/IES
20 RP-8-22 notes a "practical difference for 4000K, which had greater
21 detection distances especially for pedestrians, than any of the other light
22 sources." The City's 3000 CCT 58W LED therefore does not align with
23 ANSI/IES RP-8.

24

25 12) Ann Arbor Witness Naheedy inaccurately concludes that Ann Arbor was
26 financially disadvantaged as a result of the Company now replacing HPS

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1 fixtures with its standard stock LED fixtures. This assertion is incorrect for
2 two reasons. First, Ann Arbor selected to sample a 58W LED fixture with
3 a 3000 CCT, whereas the Company's standard stock LED replacement is a
4 58W 4000 CCT fixture.

5
6 Second, Ann Arbor (and MI-MAUI above) incorrectly frames the
7 Company's extension of its current methodology in replacing obsolete MV
8 fixtures that fail with LEDs to it now including replacing obsolete HPS
9 fixtures that fail with LEDs. Both MV and HPS are lighting technologies
10 that are no longer available. This is not a new policy or methodology, but
11 instead an extension of an already Commission-approved methodology that
12 has been employed since 2017.

13

14 13) The Commission should dismiss Witness Stults proposal (similar to MI-
15 MAUI's bill credit proposal) that the City receive a bill credit in recognition
16 that they are paying for the conversion of other customers making the
17 transition from HID to LED fixtures. If Witness Stults proposal were to
18 be adopted, millions of dollars would be added to the municipal
19 streetlighting rate base (70% of company-owned streetlights are now LEDs)
20 which would result in higher rates.

21

22 **Q5. Are you sponsoring any exhibits in this proceeding?**

23 A5. Yes. I am sponsoring the following exhibits:

24	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
25	A-40	EE1	Isakson Rebuttal Testimony Consumers U-21389
26	A-40	EE2	U-21534 MAUIDE-4.28b 2019-2023 O&M Spend

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1	A-40	EE3	Riverview Capital Cable Replacement Job
2	A-40	EE4	U-20147 DGP Excerpt
3	A-40	EE5	NDA MAUIDE-5.48 Leotek Removal of Crossover
4			Chart Correspondence
5	A-40	EE6	2023 FHWA Lighting Handbook Excerpt
6	A-40	EE7	2023 FHWA Excerpt – Lighting Level
7			Recommendation
8	A-40	EE8	Revised 100W HPS Analysis With LLF
9	A-40	EE9	U-21534 DEMAUI-2.1 (DEMAUI-4)
10	A-40	EE10	U-21534 DEMAUI-6 U-18322 Witness Miller
11			Excerpt
12	A-40	EE11	U-21534 DEAA-2.1bi – DEAA-2.1ci

13

14 **Q6. Were these exhibits prepared by you or under your direction?**

15 A6. Yes, they were.

16

17 **Q7. Are there any aspects of testimony provided by MI-MAUI and the City of Ann**
 18 **Arbor not specifically addressed in your rebuttal testimony?**

19 A7. Yes, the absence of a discussion of other matters discussed in both the MI-MAUI
 20 and Ann Arbor direct testimonies is not an indication that I agree with the
 21 information provided or arguments presented. Considering the substantial
 22 discussion involving the various aspects of my testimony, and the limited time
 23 available to respond, I have focused my rebuttal testimony on the most significant
 24 areas of disagreement.

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1 **REBUTTAL OF MI-MAUI WITNESS BUNCH**

2 **DISCONTINUATION OF CIAC FOR GROUP/PROJECT CONVERSIONS AND**

3 **FUTURE CREDITS FOR EARLY LED ADOPTERS**

4 **Q8. Do you agree with Witness Bunch's statement on page 21, lines 7-9 of his direct**
5 **testimony that "[t]here is no justification to charge CIAC for a customer-**
6 **requested project that will be cheaper for the Company to implement than if**
7 **the customer did nothing and thus reactive conversions were the way every**
8 **light in the City were addressed."**

9 A8. No. Witness Bunch inappropriately conflates two separate and distinct,
10 longstanding Commission supported processes as it pertains to both reactive
11 conversions and customer requested projects specific to HID replacements, in
12 justifying the elimination of customer CIAC.

13 The Company's proposed change when replacing through reactive conversions
14 upon failure, high pressure sodium (HPS) lights due to their obsolescence with
15 LEDs, is very much consistent with how the Company currently addresses mercury
16 vapor (MV) in-service failures. When responding to a MV light failure, the
17 Company will replace it with its equivalent LED fixture at no cost to the customer.
18 For customer-requested conversion projects, customer CIAC has been a long-
19 standing Commission-supported practice, the intent of which is to not socialize the
20 cost of a project that benefits a single customer, to all other customers within that
21 rate class.

22

23 **Q9. You stated that your proposed change to replace HPS fixtures upon failure**
24 **with an equivalent LED is not a departure, or new methodology employed by**

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1 the Company, but instead follows the same Commission-approved
2 methodology when replacing MV fixtures upon failure. Can you elaborate?

3 A9. Yes. As I explained on page 7, lines 10 - 17 in my direct testimony in the instant
4 case, “Pursuant to the Energy Policy Act of 2005, Mercury Vapor lamps became
5 obsolete” and “DTE Electric began to convert failed MV lighting to LED for E1
6 Option I customers starting in 2017 in accordance with the Commission’s order on
7 January 31, 2017, in Case No. U-18014.” (emphasis added). HPS technology has
8 now reached the same point of de-facto obsolescence as its MV counterpart. This
9 is a continuation of long-standing policy to allow those customers who have chosen
10 to keep the lighting system they and their community members are comfortable
11 with, regardless of lighting technology type.

12

13 **Q10. Is Witness Bunch correct in stating on page 23, lines 4-10 that this policy**
14 **change “...seems like an effort by DTE to entice customers to rush into a**
15 **process that will result in those customers covering the project costs for**
16 **converting from HID’s to LED’s when they would not have to pay hundreds of**
17 **thousands – or even millions – of dollars up front for that conversion if they**
18 **just waited for their existing lights to fail?”**

19 A10. No. As shown in “Table 3: E1 Option I Light Counts by Type” on page 8, line 12
20 of my direct testimony, there are still 10,695 MV municipal streetlights still in
21 service, or 6% of our total municipal lights owned, operated and maintained by
22 DTE. It is telling however, that even with grant funding offered by the Southeast
23 Michigan Council of Governments (SEMCOG) to offset approximately 80% of the
24 total cost of streetlight conversion project, municipal customers representing only

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1 11,000 of the approximately 52,000 (MV+HPS+MH)¹ remaining HID lights opted
2 take advantage of this grant. Further, DTE reached out to all of its non-LED
3 customers when the SEMCOG grant program in an effort to make the “aware and
4 assisted several communities to complete their applications.^{2”}

5

6 **Q11. Has Witness Bunch recommended Customer CIAC be eliminated or taken**
7 **contradictory positions on the application of CIAC in prior rate case**
8 **proceedings?**

9 A11. Yes, both. This is the 3rd consecutive rate case in which Witness Bunch has
10 advocated for the elimination of CIAC. As noted on page 476 of Order U-20836,
11 DTE participated in the Staff facilitated CIAC workgroup held in early 2023, in
12 which MI-MAUI/Ann Arbor advocated to have conversion costs excluded from
13 CIAC. Witness Bunch again argued in Case No. U-21297, that CIAC for HID –
14 LED conversions be eliminated because “...customers who paid for past
15 conversion will be able to recover their investment^{3”} The Commission in its order
16 correctly stated that it “...agrees with the ALJ and declines to adopt new calculation
17 methods for CIAC. Here too (and as discussed in the Cost of Service section of
18 this order, below) the Commission is not persuaded to adopt MI-MAUI’s proposal
19 to end the CIAC charge. The Commission finds that the CIAC charge remains
20 applicable to this conversion work.^{4”}

21 Interestingly, Witness Bunch took the opposite position during Consumers Case
22 No. U-21389, in which he advocated that customers be charged the full cost of new

¹ Bellini U-21534 Direct Testimony, page 8, line 12 “Table 3: E1 Option Light Counts by Type”

² Bellini U-21534 Direct Testimony, page 7, line 24

³ U-21297 MI-MAUI exceptions, p.4

⁴ Order U-21297, Page 139

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1 streetlighting installations.⁵ As Staff Witness Isakson pointed out in his rebuttal
2 testimony (Exhibit A-40, Schedule EE1), Mr. Bunch contradicted himself when
3 testifying in concurrent DTE Electric and Consumers cases, U-21297 & U-21389,
4 respectively. When asked if Mr. Bunch took contradictory positions, Staff Witness
5 Isakson stated “Yes. In DTE’s electric rate case U-21297, MI-MAUI advocated for
6 the elimination of CIAC charges for the conversion to LED lights. In that case MI-
7 MAUI argued that the basic reason to assess a CIAC fee was if the customer
8 receives a special service or benefit then other customers should not have to pay for
9 it through rates.⁶”

10

11 **Q12. Please summarize your position on Witness Bunch’s proposal to eliminate**
12 **CIAC for planned conversions and recommendation to the Commission.**

13 A12. Witness Bunch has introduced no new evidence that demonstrates the Company
14 has departed from Commission-approved CIAC practices related to HID-LED
15 conversions. Bunch contends that the sunseting of HPS has created a new and
16 unique inequity for early adopters and those municipal customers that continued to
17 proactively convert their systems to LED. This simply is not true. Similar to the
18 Company’s approach to MV, the Company proposes to replace failed luminaires
19 identified through reactive maintenance with an equivalent LED fixture, and for
20 those proactive HPS – LED conversion projects that municipalities decide to move
21 forward with, we propose to “offer a HPS per light labor credit starting in 2024 for
22 those municipalities that have decided to proactively convert to LEDs for which
23 projects have not yet begun.⁷”

⁵ Bunch U-21389 Direct Testimony, page 7, line 21 – page 8, line 7

⁶ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 23, lines 1-7

⁷ Bellini U-21534 Direct Testimony, page 11, lines 18-19

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1 Second, as has been argued in prior rate cases, the discontinuation of CIAC would
2 result in the Company absorbing full project conversion costs into rate base, that
3 would be socialized among all E1 Option I municipal customers. As a quick
4 example, if the Company were then required to convert all remaining 40,000 HPS
5 lights without customer CIAC, it is likely those conversion costs would result in
6 absorption into rate base, between \$15M - \$20M depending on the cost of materials
7 and labor at the time of conversion.

8 Therefore, the Company recommends that the Commission again reject MI-
9 MAUI's proposal requiring the Company to stop charging CIAC for project
10 conversions.

11

12 **Q13. In conjunction with Witness Bunch's proposed discontinuation of CIAC, he is**
13 **also proposing that "the Commission instruct DTE a bill credit method...and**
14 **to consult with staff and intervenors in the development of its proposed credit**
15 **scheme in advance of its next filing.⁸" Do you agree with this credit scheme**
16 **proposal?**

17 A13. No. This appears to be an attempt to circumvent the Commission's previous
18 positions in both DTE and Consumers prior rate case filings in which they have
19 affirmed the appropriateness of customer CIAC pertaining to proactive customer
20 HID-LED conversions. As I mentioned in the previous section, Mr. Bunch has
21 introduced no new evidence indicating the Company has deviated from its
22 Commission approved CIAC methodology.

23 As discussed in prior Company rate case proceedings, credits paid to municipal
24 customers who've already made the choice to convert over the past several years

⁸ Bunch U-21534 Direct Testimony, page 29, lines 1-4

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1 would result in millions of dollars being rate based and socialized among all
2 customers. Add to that, the cost to convert the remaining 40K HPS customers as I
3 mentioned previously, would see rates go exponentially higher for the entire
4 municipal customer class.

5 Highlighting the impact to customers that a credit scheme would have, I again turn
6 to Staff Witness Isakson's rebuttal to MAUI's credit proposal in Consumers case
7 U-21836, to eliminate all CIAC charges assessed to streetlighting customers and
8 provide a customer "CIAC offset credit."⁹ Isakson concludes, "It is unclear who
9 would pay the expense related to 9.4 years of tariff payments that represent MI-
10 MAUI's CIAC offset credit. Logically, the revenue shortfall created by issuing
11 MI-MAUI's proposed CIAC credit would be paid for by all lighting customers."¹⁰

12

13 **Q14. You noted that the Commission has rejected Witness Bunch's prior proposals**
14 **to eliminate customer CIAC for HID-LED conversions but indicates in his**
15 **direct testimony that "Consumers worked out a system of time-limited bill**
16 **credits that protect early-mover LED customers against the rate impacts of**
17 **those later no-CIAC conversions."¹¹ Why does Consumers provide this credit**
18 **if the Commission has repeatedly rejected MAUI's proposals?**

19 A14. Unfortunately, Mr. Bunch failed to provide any context in his direct testimony as
20 to what gave rise to Consumers bill credit mechanism, and only chose to present
21 the model itself. He did not provide the contextual definition for "early-mover LED
22 customers"¹² referenced in prior Consumers case U-20697. This model should be
23 disregarded by the Commission.

⁹ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 22, line 10

¹⁰ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 22, lines 10-12

¹¹ Bunch U-21534 Direct Testimony, page 26, lines 11-13

¹² Bunch U-21534 Direct Testimony, page 26, line 12

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1

2 **Q15. Were you able to identify any information from prior Consumers rate case**
3 **filings that would provide insight into the definition of an “early-mover LED**
4 **customer” and whether it would have a consistent application to DTE**
5 **municipal LED customers as presented here by Witness Bunch?**

6 A15. Yes. In reviewing MI-MAUI’s DEMAUI-6 discovery response, an “early-mover
7 LED customer” as referred to in Consumers Case No. U-20697 can generally be
8 defined as a municipal customer who proactively installed and “paid to convert
9 their streetlights to a LED technology prior to the Commission order approving the
10 burnout replacement program in Case No. U-18322.¹³” I will assume that this is
11 Mr. Bunch’s reference to an early-mover LED customer. At the heart of the matter
12 in the Consumers case, there are two issues. First, it appears from Witness Bunch’s
13 revised public direct testimony in Case No. U-20697, that Consumers had
14 previously charged customer CIAC upon HPS fixture failure prior to the
15 Company’s policy change to no longer charge CIAC as part of their burnout
16 replacement program. Second, Bunch notes that customer installed, first generation
17 LEDs have a much shorter life (15 years), than do the Company’s (referring to
18 Consumers Energy) preferred model (24 years). Witness Bunch’s proposed
19 Consumers bill credit sought to rectify both the difference in Company installed
20 LEDs with a longer life, and the shift in policy change in Consumers deciding to
21 no longer require CIAC upon failed fixtures. The contention being, had the
22 customer done nothing and let the fixture burn out, they would have received an
23 LED with a longer life at no cost.

¹³ Exhibit A-40 Schedule EE10 U-21534 DEMAUI-6 U-18322 Witness Miller Excerpt

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1 **Q16. Is there a parallel between Consumers bill credit for “early-movers” and DTE**
2 **installing LEDs upon failure of an HPS fixture?**

3 A16. No. As I have mentioned previously, similar to MVs becoming obsolete and being
4 replaced upon failure with an LED, HPS fixtures are being sunset by most lighting
5 manufacturers. Therefore, the DTE is similarly extending the same LED
6 replacement practice to HPS fixture failures. Second, DTE has not changed its
7 CIAC policy as was the case with Consumers. Therefore, the circumstances that
8 led to Consumers bill credits to its early-mover LED customers did not occur here,
9 has no bearing on this issue, and therefore are not relevant in this proceeding.

10

11 **Q17. What is your recommendation to the Commission regarding MI-MAUI’s**
12 **proposed bill credit scheme?**

13 A17. As I mentioned above, in addition to the circumstances that gave rise to Consumers
14 bill credit program having no relevance here, this scheme would have a significant
15 and adverse impact on customer rate design. We are at nearly 70% LED
16 penetration for municipal streetlights.¹⁴ Unwinding and providing credits to LED
17 customers would result in millions of dollars of increased rate base. As such, the
18 Commission should reject MI-MAUI’s credit scheme proposal.

19

20 PROPOSED ADJUSTMENT TO E1 STREETLIGHT SALES FORECAST

21 **Q18. Witness Bunch proposes two input value adjustments (a third being the total,**
22 **unadjusted electric sales forecast for which Mr. Bunch does not recommend**
23 **any changes) to the Company’s sales forecast which include “the Night Patrol**

¹⁴ Bellini U-21534 Direct Testimony, page 8, line 12 “Table 3: E1 Option Light Counts by Type”

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1 **outage rate...and, the number of HID fixtures remaining under the E1, Option**
2 **I rate.¹⁵ Do you agree with these proposed adjustments?**

3 A18. Generally, yes. My recommendation to the Commission is specific to using the
4 night patrol outage rate as a continuing proxy for total system outages. As I note in
5 my direct testimony, "...depending on prior patrol results and repair detail (i.e.
6 large percentage of outages noted in a single municipality or high concentration of
7 outages in a specific area), the Company may adjust the timing of the next
8 scheduled night patrol.¹⁶" This means that as our night patrols become more
9 targeted to those communities that are experiencing higher than average outage
10 events, this has the potential to skew the % of lights canvassed in a given year,
11 higher. In other words, this is less of a representative sample as we continue to
12 target specific communities. I would recommend that the Commission order the
13 Company to work with Staff and MI-MAUI to establish a reasonable and more
14 refined methodology that provides a closer representation of Company owned,
15 municipal streetlight outages.

16

17 **Q19. Does the Company's Sales Forecast already include an adjustment for non-**
18 **working lights?**

19 A19. Yes. The Company has already reduced its sales forecast by 3.25% as ordered by
20 the Commission in Case No. U-21297. Therefore, the proposed adjustment to the
21 Company's sales forecast of 4.06% should only reflect the incremental difference
22 of 0.81%.

¹⁵ Bunch U-21534 Direct Testimony, page 33, lines 7-16

¹⁶ Bellini U-21534 Direct Testimony, page 15, lines 18-20

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1 PROPOSED DISALLOWANCES TO BOTH STREETLIGHTING & PAINTING

2 **Q20. In reference to streetlight post inspections and post painting, Witness Bunch**
3 **states that he is concerned that “...the Company has a history of vastly over-**
4 **collecting for this area.¹⁷” Do you agree with this statement, and is it presented**
5 **in the proper context as compared to other O&M spend areas?**

6 A20. Witness Bunch does correctly state the Company’s as-filed position as it pertains
7 to its anticipated reduction and taken into account in the instant case, for spend for
8 both inspections and post painting. The Company does anticipate lower pole
9 inspection activity now that streetlight-only wood poles are being identified for
10 replacement through Distribution’s pole-top maintenance program, and a lower
11 painting spend due to the use of one painting contractor. Where I disagree with Mr.
12 Bunch is the narrow presentation of approved spend versus actual spend for only
13 these two programs. Mr. Bunch presents a simple table on page 35, line 1 of his
14 direct testimony, that compares Commission-approved spend for calendar years
15 2022 and 2023 (Orders U-20561 & U-20836, respectively) that shows the
16 Company’s spend was \$271K and \$384K less than approved for both programs for
17 each year. I have modified Witness Bunch’s table (see Table 1 below) to include
18 for calendar years 2022 and 2023 to include net O&M spend¹⁸:

¹⁷ Bunch U-21534 Direct Testimony, page 34, line 8

¹⁸ Exhibit A-40 Schedule EE2 MAUIDE-4.28b 2019-2023 O&M Spend

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Table 1 - Updated Company O&M Spend – Inspections/Painting/Outage Maintenance

	CY 2022/U-20561		CY 2023/U-20836	
Approved Spend				
(Inspection + Painting)	\$	489,000	\$	486,580
Actual Spend	\$	218,005	\$	102,886
Difference	\$	270,995	\$	383,694
Approved Net O&M				
Outage Maintenance	\$	1,355,786	\$	1,027,224
Actual Spend	\$	1,943,409	\$	1,980,819
Difference	\$	(587,623)	\$	(953,595)
Total Difference when				
including Outage	\$	(316,628)	\$	(569,901)

2

3

4

5

6

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8

9

10 **Q21. Witness Bunch also recommends that the Company “file as part of their next**
 11 **rate case a report on actual costs with amounts recovered in rates, looking**
 12 **back 5 years.¹⁹” Do you agree with this proposal?**

13 A21. No, I do not. As I stated previously, isolating specific areas of Commission-
 14 approved spend to actuals can be misleading. Similar to budgeting and forecasting,
 15 Company projections are snapshots in time that are based on information available
 16 at that time. There will be variances both favorable and unfavorable when actual
 17 costs are incurred, as was the case for post painting, post inspections, and as the

¹⁹ Bunch U-21534 Direct Testimony, page 36 line 23 – page 37 line 1

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1 Company included here, O&M outage spend. Mr. Bunch's presentation and
2 interpretations drawn were based on an incomplete set of facts and therefore do not
3 support valid conclusions.

4 Therefore, I recommend that the Commission reject both MI-MAUI's proposed
5 disallowance for post painting & post inspections as well as the proposal to provide
6 a report on actual costs with amounts recovered over the past 5 years. Conversely,
7 if the Commission approves the recommended disallowances for post painting and
8 inspections, I recommend that the Company's total O&M spend should be
9 approved as reflected in Table 1 above.

10

11 PROPOSED DISALLOWANCE FOR UNDERGROUND CABLE REPLACEMENT
12 AND INCLUSION OF PROGRAM COSTS IN DISTRIBUTION GRID PLAN

13 **Q22. Witness Bunch recommends that the Commission disallow the Company's**
14 **capital investment costs for its underground cable replacement program**
15 **because DTE has not "provided reliability or cost data to justify this**
16 **program²⁰" and that these costs "have not been incorporated as part of DTE's**
17 **DGP.²¹" Do you agree with Witness Bunch's proposed disallowance?**

18 A22. No, for two reasons. First, DTE has laid out the specific criteria used to prioritize
19 and replace failed/end-of-life underground cable. The criteria referenced in DTE's
20 response to MAUI U-21534 discovery question MAUIDE-4.26 (Exhibit MAU-23
21 as part of Bunch's U-21534 direct testimony) are 1) age of cable, 2) pedestrian
22 conflict (level of pedestrian traffic), 3) recurring outages, 4) number of lights out
23 on a circuit, and 5) type of road. The Company has also provided cost data as
24 reflected on line 5 of its Exhibit A-12, B5.5, titled "Cable Replacement."

²⁰ Bunch U-21534 Direct Testimony, page 37, line 12

²¹ Bunch U-21534 Direct Testimony, page 37, lines 19-20

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1 Second, Community Lighting operates as a separate unit for which investments are
2 made unique to its assets and infrastructure (i.e. posts, fixtures, overhead &
3 underground cable, etc.), and therefore not part of the Distribution Grid Plan
4 (DGP).

5

6 **Q23. Please elaborate on the how DTE applies these criteria in selecting and**
7 **replacing cable as part of this program in relation to its projected capital**
8 **expenditures shown in Exhibit A-12, Schedule B5.5**

9 A23. This can best be demonstrated through a project the Company recently identified
10 as an underground capital cable replacement candidate. By way of background,
11 there have been several previously reported outages (as shown in the notes to the
12 right of the sketch) along the circuit located in the City of Riverview referenced in
13 Exhibit A-40, Schedule EE3. DTE has previously responded by making “locate and
14 repairs,” charged to O&M reactive maintenance, in which small sections of cable
15 are replaced to fix the specific fault (note that this type of repair does not extend
16 the useful life of the cable or mitigate future faults that may occur on the same
17 stretch of cable, as was the case here). The attached job sketch in Exhibit A-40,
18 Schedule EE3 “Riverview Capital Cable Replacement Job” shows contractor cable
19 testing results specific to a circuit in Riverview, and the notes on the job that were
20 entered into our outage management system, Kloudgin. As this sketch indicates,
21 cable testing revealed 3K – 10K Ohms of resistance (newly installed cable should
22 reflect close to zero resistance), indicating that the underground cable is end of life
23 and prone to future failures. In comparing to our criteria used for prioritization, the
24 age of the cable is at least 39 years old (using the pole install date is an indication
25 of the age of cable), there have been outages reported previously on this circuit, the

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1 roadway has high pedestrian traffic, and 9 lights are currently impacted. This job is
2 representative of the types of cable replacement candidates the Company targets
3 for long-term repairs. Mr. Bunch's proposal to deny recovery for these costs, is
4 counterproductive, will result in the Company continuing to engage in expensive
5 and reactive repairs, addressing only symptomatic issues, and unnecessarily
6 increasing outage counts and customer discontent.

7 Table 2 below shows Company O&M costs for locate and repairs for 2022 and
8 2023:

9 **Table 2 - O&M costs for locate and repairs for 2022 and 2023:**

	Events	Cost
2022	2,096	\$ 898,555
2023	1,520	\$ 672,477

10 By contrast, the Company replaced a total of approximately 71,000 ft of cable in
11 2022 and another 74,000 ft of cable in 2023, under the cable replacement program.
12 If the Company is denied recovery of its capital costs, repairs involving
13 underground cable failures will only be able to be made through locate and repairs.
14 As Table 2 indicates, these repairs are costly and do not mitigate the root cause.

15

16 **Q24. Is Mr. Bunch correct in stating that the second reason for denial of recovery**
17 **for the underground cable replacement program is that it was not included in**
18 **the Company's DGP?**

19 A24. No. As I mentioned earlier, Community Lighting's assets are separate and distinct,
20 and operates independently from DTE Distribution Operations. The focus of the
21 DGP is specific to distribution investments, not streetlighting. The Company
22 defines the composition of the distribution grid and customers impacted (filed in
23 Case No. U-20147) as including "approximately 31,000 miles of overhead

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1 distribution lines and 14,500 miles of underground distribution lines. Its service
2 territory encompasses 7,600 square miles and includes approximately 2.3 million
3 residential, commercial and industrial customers.²²”

4

5 Further, Community Lighting from a cost of service/rate design perspective,
6 maintains its own rate base, a separate set of projected capital and O&M
7 expenditures, etc.

8

9 **Q25. What is your recommendation to the Commission with respect to Witness**
10 **Bunch’s proposal to disallow recovery of underground capital cable**
11 **replacement costs?**

12 A25. I recommend that the Commission reject this proposal. The Company has
13 demonstrated that there is a direct and positive impact on lighting system reliability,
14 customer satisfaction, and a long-term cost benefit by reducing expensive locate
15 and repair work that does not mitigate the root cause, which is the failed
16 underground cable itself. The Company also has demonstrated Community
17 Lighting assets, are in fact separate and distinct from Electric Distribution, are
18 appropriately excluded from its DGP.

19

20 PROPOSED COMPANY OUTAGE PERFORMANCE AND MI-MAUI PROPOSAL
21 FOR A REPORTING SCHEME ON COMPANY OUTAGE CAUSES AND COSTS

22 **Q26. Though Witness Bunch supports recovery of the Company’s outage costs, he**
23 **caveats his support with a proposal for the Commission to “order the**
24 **Company to provide a proposed reporting scheme within three months of its**

²² Exhibit A-40, Schedule EE4 U-20147 DGP Excerpt

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1 **final order in this case, for review and discussion with Staff and**
2 **Intervenors.²³” Do you agree with this proposal?**

3 A26. No, but I do offer an alternative proposal below for the Commission to consider.
4 First however, it is important to discuss Witness Bunch’s premise as to why he
5 believes this proposal is necessary. Witness Bunch’s premise revolves around three
6 central themes. The first theme is that DTE’s outage restoration performance
7 continues to get worse. The second theme is that to the extent there have been
8 reductions, it is solely based on the sheer number of lights converted to LED. The
9 last theme being that since the Company has deployed a new outage management
10 system (OMS), it should have necessary information to provide root cause data,
11 costing data, and breakout per light.

12

13 **Q27. Please explain why you think even though Witness Bunch, while**
14 **acknowledging both outage frequency and duration are declining, states that**
15 **these declines “are not attributable to the Company’s outage response**
16 **efforts²⁴”**

17 A27. As I have discussed previously in rebuttal during Case No. U-21297, in order for
18 Witness Bunch to propose a reporting scheme, he needs there to be persistent
19 problem that cannot be solved without such a scheme. Here, I point out two
20 problems with Mr. Bunch’s assertion that performance is getting worse. First, by
21 way of his own testimony, Witness Bunch arbitrarily shifts to a pre-pandemic
22 baseline of 3.57 days without explanation or proper context. The reality is that the
23 Company as well as the rest of the world were negatively impacted by Covid
24 resulting in supply chain and resourcing constraints. Additionally, the Company

²³ Bunch U-21534 Direct Testimony, page 43, line 22 -page 44, line 1

²⁴ Bunch U-21534 Direct Testimony, page 40, line 13

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1 has been impacted by a high frequency of catastrophic storms since 2020, that
2 pulled our crews away from responding to lighting repairs. Despite these
3 challenges, the Company has consistently continued to drive down its duration from
4 a peak of 5.22 days in 2021 to 4.16 days in 2023 (U-21534 Bellini Direct
5 Testimony, Exhibit A-25, Schedule O1).

6 Second, as I have mentioned in my U-21297 rebuttal, Mr. Bunch held DTE's outage
7 performance as a baseline when critiquing Consumers in case U-20697, filed in
8 2020. In direct testimony in that case, he used DTE's outage performance to
9 contrast that of Consumers when reflecting on their 2018 outage duration.
10 Specifically, he stated "Over the last ten years, DTE has reduced average outage
11 duration from 8.5 days to 3.5 days and has reduced the incidence of outages longer
12 than 10 days almost 90%.²⁵" He went on to recognize DTE's efforts as "significant
13 improvements."

14

15 **Q28. Witness Bunch states "[a]ll reductions in outage counts can be attributed to**
16 **increased deployment of LED luminaires...²⁶" Is this true?**

17 A28. No. Witness Bunch's statement that all reductions are due to LED conversions is
18 simply not true. As referenced on page 16, lines 6-8 of my direct testimony when
19 discussing the underground cable replacement program, outages are generally the
20 result of a failed luminaire, failed wiring or components such as a photocell, or
21 failed underground cable. While replacement of HIDs with LEDs may play a part,
22 actual outage data as reflected in Exhibit A-25, Schedule O1 "Community Lighting
23 Outage Duration," in my direct testimony, coupled with Table "Community

²⁵ Witness Bunch's direct testimony, Consumers case U-20697, page 55, lines 21-22 through page 56, lines 1-2.

²⁶ Bunch U-21534 Direct Testimony, page 42, lines 5-6

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1 Lighting Assets by Type (2012-2023)” also in my direct testimony on page 8, line
2 4, provide us with data from which we can draw a fact-based conclusion. From
3 2017 – 2023, HIDs decreased by nearly 50%, being replaced generally with LEDs.
4 Reviewing outages on line 2 of Schedule O2, outage events increased from 2017
5 and peaking in 2019. This is not a coincidence, but instead 2020 happened to be
6 the first year of the Company’s proactive night patrol program, which Witness
7 Bunch now supports.²⁷ This has allowed our crews to not just replace failed
8 fixtures, but also address wiring problems and identify other root cause issues, such
9 as underground cable failures. As such, there was a steady decline in each
10 consecutive year in reported outages since the Company’s night patrol program was
11 rolled out. If Mr. Bunch’s assertion that all reductions in outage were the result of
12 LED conversions, there would have been a linear decline in both outage events and
13 reduction in HIDs in service since 2017, which was not the case.

14

15 **Q29. Witness Bunch claims the Company’s new outage management system “will**
16 **greatly increase the Company’s ability to track and report on root causes and**
17 **their costs.²⁸” Do you agree with this characterization of the Company’s new**
18 **OMS and its capabilities?**

19 A29. Somewhat. While there is merit in our ability to better track events and know where
20 we are seeing recurring outages, Witness Bunch is overstating the Company’s new
21 OMS capabilities as it relates to the system being able to provide a “taxonomy of
22 root cause outages, causes of delays in restoration, cost breakdowns, and other
23 data...”²⁹ I have clearly outlined the benefits of our new OMS system - Kloudgin,

²⁷ Bunch U-21534 Direct Testimony, page 37, lines 4-9

²⁸ Bunch U-21534 Direct Testimony, page 43, lines 5-6

²⁹ Bunch U-21534 Direct Testimony, page 44, lines 1-2

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1 and its benefits, in my direct testimony (page 21, line 21 – page 22, line 2). These
2 attributes differ from Witness Bunch’s expectations.

3

4 **Q30. Has Witness Bunch advocated that the Company be required to adopt other**
5 **outage management systems in the past noting that they possessed similar**
6 **reporting capabilities and characteristics?**

7 A30. Yes. Mr. Bunch in his direct testimony in case U-20836, proposed that the
8 Commission “[i]nstruct the Company to file plans for a networked lighting controls
9 pilot as soon as possible.³⁰” He went on to state, *without citing to any supporting*
10 *evidence* that with networked lighting controls “operating costs are reduced...” and
11 construction crews can “bring along whatever material is needed to resolve each
12 outage because the light can send diagnostic data...” and that “the costs of installing
13 and operating networked controls is largely, if not entirely, offset by reduced
14 operating costs...”³¹ When questioned through Company rebuttal as to how MI-
15 MAUI member Ann Arbor’s networked lighting control pilot had performed, Mr.
16 Bunch ceased to mention anything more on this topic, and has remained notably
17 silent since on the benefits of networked lighting control systems.
18 I mention this in relation to our OMS system, Kloudgin and the contrast between
19 the characteristics and benefits we expect to receive, with Mr. Bunch’s
20 expectations. While I can appreciate the desire to have access to this type of data
21 in the manner that Witness Bunch believes is available, the reality is, similar to his
22 promise of cost savings and efficiencies garnered by networked lighting controls,
23 that is not what is available to us today at a justifiable cost that the entire municipal
24 rate class would ultimately bear.

³⁰ Bunch U-20836 Direct Testimony, page 66, lines 14 - 15

³¹ Bunch U-20836 Direct Testimony, page 65, line 11 – page 66, line 2

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1 **Q31. You mentioned that Ann Arbor has piloted a networked lighting system**
2 **solution. Were you able to obtain any insight as to the effectiveness of this**
3 **system in terms of data collection?**

4 A31. When we asked Ann Arbor Witness Naheedy to provide data similar to the data
5 that Witness Bunch claimed was available through a networked lighting system or
6 through any other outage management system currently in use (DEAA-2.1bi
7 through DEAA-2.1ci), nothing was available.³² This is peculiar given that Ann
8 Arbor has been a MI-MAUI member for several years, yet Witness Bunch appears
9 not to have worked with its own member to employ such solutions he advocates
10 and claims DTE has readily available.

11

12 **Q32. Would you then recommend a different proposal than the one Witness Bunch**
13 **offered?**

14 A32. Yes, I would. I believe it is reasonable for a Staff facilitated workshop in which we
15 can discuss features of the Company's OMS system, what it is capable of doing and
16 not capable of doing and discuss the potential for future enhancements and whether
17 or not such investments would be prudent relative to their benefits.

18

19 LED SELECTION METHODOLOGY AND PROPOSAL FOR CONTINUED LED
20 CAPITAL DISALLOWANCE

21 **Q33. Witness Bunch on page 49, lines 17-19, continues to contend that DTE has**
22 **again “failed to meet the clear standard that the Commission set in case no. U-**
23 **21297 which is to demonstrate that its costs are consistent with reasonable**
24 **efforts to comply with roadway lighting standards.” As such, he further**

³² Exhibit AA-40 Schedule EE11 DEAA-2.1bi – DEAA2.1ci

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1 recommends a cumulative disallowance of either \$7,705,567 or using
2 Consumers Energy's LED equivalencies as a benchmark then the disallowed
3 amount should be \$5,833,539.³³ Do you agree that DTE still fails to meet the
4 standard set by the Commission?

5 A33. No, I do not. I will focus my responses on four critical topics: 1) Why Leotek's
6 chart which they no longer support, is fundamental to this topic, 2) Witness Bunch's
7 misstatement of fact regarding color-correlated temperature (CCT) LEDs and
8 allegation that DTE is out of step with the industry, 3) Witness Bunch's inaccurate
9 assertion that Don McLean's analysis demonstrates DTE over light its roadways,
10 and 4) additional support for the Company's recommendation in my direct
11 testimony (page 36, lines 15-20) relating to a Staff facilitated technical workshop.

12

13 **Q34. Why is Leotek's decision to no longer support its crossover chart that was used**
14 **as the basis for Witness Bunch's proposal for disallowance and as a proxy for**
15 **DTE to use as a guide for installing lights for HID-LED conversions important**
16 **for the Commission in considering this topic?**

17 A34. It is important for two reasons. First, Witness Bunch in his U-21297 direct
18 testimony, placed sole reliance on advocating that the Company adhere to Leotek's
19 crossover chart when replacing its 100W and 250W HPS fixtures. When asked if
20 the Company should "follow the LED crossover recommendations of its primary
21 LED manufacturer," Bunch answered, "Yes, it should."³⁴ In essence, this crossover
22 chart became the new standard by which the Company was required to use in
23 replacing its 100W and 250W HPS during conversion projects.

³³ Bunch U-21534 Direct Testimony page 68, lines 13-16

³⁴ Bunch U-21297 Direct Testimony, page 24, lines 1 - 3

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1 Second, this crossover chart was used as a basis in Commission order U-21297 to
2 calculate the Company's LED disallowance as proposed by Bunch. He stated "I
3 can use witness Bellini's workpaper to find the difference in cost between the
4 Leotek recommended model, and the LEDs that DTE chose to install instead.... I
5 find that DTE overspent on unnecessarily bright LED luminaires in the amount of
6 \$5,835,192.³⁵"

7

8 **Q35. Why has the Company continued to install 58W and 136W LED luminaires**
9 **after the Commissions December 1st, 2023 order in U-21297 was received?**

10 A35. As part of the Commission's order, it cited on page 137 of the Commission's
11 December 1st order in U-21297, "Absent convincing evidence to the contrary, the
12 ALJ found that the crossover recommendations are reasonable."

13 DTE decided to reach out to Leotek as part of a fact-finding effort to understand
14 how the chart should be interpreted. In response to MAUIDE-5.48 (attached here
15 as Exhibit A-40, Schedule EE5 "MAUIDE-5.48 Leotek Removal of Crossover
16 Chart Correspondence"), I explained that we discussed how the chart was
17 developed and should be interpreted with Leotek's executive level personnel and
18 other key Leotek team members, none of whom could explain it. They decided that
19 it could not be explained and therefore removed it.

20 Without this chart, DTE decided the most prudent course of action was continuing
21 to install its 58W and 136W LEDs until further guidance can be provided by the
22 Commission. At the same time the Company engaged two industry experts as I
23 discussed in my direct testimony, to provide an assessment of the Company's LED

³⁵ Bunch U-21297 Direct Testimony, page 25, lines 15 - 20

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1 selection methodology for HID-LED conversions. Both experts independently
2 confirmed that our methodology was sound.³⁶
3

4 **Q36. Did Witness Bunch provide any evidence that he reached out to Leotek to**
5 **discuss the crossover chart?**

6 A36. No, even though Mr. Bunch had ample time in which to do so during this
7 proceeding³⁷. Instead, he glosses over this important fact by stating the Leotek
8 crossover chart is “not currently available³⁸” and finally admitting that “...Leotek
9 has removed that chart and now offers no conversion advice.³⁹”
10

11 **Q37. You mentioned that Bunch mis-represented ANSI/IES RP-8 in recommending**
12 **3,000K CCT further illustrating that DTE is out of step and inflexible in its**
13 **lighting choices?**

14 A37. Mr. Bunch asserts that “ANSI/IES RP-8 standard recommends luminaires around
15 3,000k on highways to improve driver visibility and reduce glare.⁴⁰” There is no
16 such guidance in this standard. To the contrary, the Federal Highway
17 Administration handbook⁴¹ (sponsored by the U.S. Department of Transportation)
18 states “at higher speeds, 4000K LED lighting might be beneficial for increasing
19 driver visibility (Engineering & Medicine, 2020). Similarly, other research has
20 shown that the use of 4000K light sources generally improves object detection
21 distance.⁴²” The Company’s standard stock LED is a 4000K CCT. I also discuss in

³⁶ Bellini U-21534 Direct Testimony, page 28, line 11 – page 29, line 18

³⁷ Exhibit A-40, Schedule EE9 U-21534 DEMAUI-2.1 (DEMAUI-4)

³⁸ Bunch U-21534 Direct Testimony, page 51, lines 9-10

³⁹ Bunch U-21534 Direct Testimony, page 55, line 16

⁴⁰ Bunch U-21534 Direct Testimony, page 60, lines 19-21

⁴¹ [FHWA Lighting Handbook \(dot.gov\) accessible at
https://highways.dot.gov/sites/fhwa.dot.gov/files/2023-05/FHWA-Lighting-Handbook_0.pdf](https://highways.dot.gov/sites/fhwa.dot.gov/files/2023-05/FHWA-Lighting-Handbook_0.pdf)

⁴² Exhibit A-40 EE6 2023 FHWA Lighting Handbook Excerpt

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1 my rebuttal to Ann Arbor Witness Naheedy later on, that IESRP-8-22 aligns with
2 4000K CCT as well.

3

4 **Q38. Are Witness Bunch's claims accurate when he says that Mr. McLean's**
5 **analysis demonstrates that the incumbent 100W and 250W HPS fixtures over**
6 **lit or drastically over lit roadways relative to current standards as claimed in**
7 **his direct testimony on page 57, line 20 and page line 5?**

8 A38. No, they are not. Both experts evaluated DTE's replacement LEDs as an equivalent
9 to the original HPS fixture. Most of these HPS fixtures when installed decades ago,
10 pre-dated any such set of formal standards that exist today. However, we shouldn't
11 also assume that those municipalities unwittingly selected fixtures that "over lit"
12 these roadways. A more plausible reason is that HPS lumen output, similar to LEDs
13 today, diminish/dim over its useful life. And similar to lighting standards today,
14 there are safety factors assumed built into the design. In other words, streetlight
15 systems are designed to overperform when initially deployed knowing lumen
16 output of the LED roadway luminaire will diminish over time. Witness Bunch
17 appears to acknowledge this fact when he states that Grand Rapids installs dimmers
18 on their 55W LEDs and "as the luminaire's light output slowly decreases over time,
19 Grand Rapids can adjust to yield constant illumination by giving the luminaire more
20 electricity.⁴³" Therefore, there must be what is referred to as a light loss factor
21 (LLF) included in the initial lighting design, the intent of which is to add a safety
22 factor, or measure of over-light to ensure adequate lumen output throughout the
23 fixtures useful life.

⁴³ Bunch U-21534 Direct Testimony, page 65, lines 14-15

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1 **Q39. Was there a light loss factor included in DTE's data provided to Mr. Mclean?**

2 A39. No, there was not. Had we included our light loss factor that include adjustments
3 for each roadway type, our luminance results are in line with published luminance
4 guidance.

5
6 **Q40. When incorporating LLF into the lighting analyses, does luminance fall within**
7 **industry standards?**

8 A40. Yes, they do. The Federal Highway Administration handbook states that "...it is
9 recommended that lighting not exceed the maintained lighting level specified for
10 the roadway by more than 50%...designers are encouraged to get as close as
11 possible to the required maintained level while not going below that level.⁴⁴"

12 Using the 100W analysis as an example, when adjusting for a LLF of 0.701, the
13 100W HPS and our recommended equivalent 58W LED replacement show a
14 positive result of 3% and 29%⁴⁵ respectively, both within the limits as set forth by
15 the FHWA. Notably, the 37W, 30W, and 27W LEDs all fall below the maintained
16 lighting level. Therefore, the result can be interpreted as neither the 100W HPS,
17 nor the Company's equivalent 58W LED were over lit, but instead provide adequate
18 lighting.

19

20 **Q41. Would you still recommend to the Commission that they order a technical**
21 **workshop determine an appropriate LED selection standard specific to HID-**
22 **LED conversions?**

23 A41. Yes, I would, but I would revise my recommendation given Witness Bunch's
24 apparent shift in now recommending an alternative disallowance amount that aligns

⁴⁴ Exhibit A-40 Schedule EE7 2023 FHWA Excerpt – Lighting Level Recommendation

⁴⁵ Exhibit A-40 Schedule EE8 Revised 100W HPS Analysis With LLF

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1 with Consumers equivalent LEDs used during its HID-LED conversions due to
2 Leotek no longer supporting their crossover chart.

3 Therefore, it would be reasonable to recommend that Staff conduct a technical
4 workshop or joint collaborative that includes Consumers so that we may compare
5 and contrast their LED selection methodology to DTE's. In addition to Consumers,
6 I would include as I recommended in my direct testimony: Leotek, both Dr.
7 Gibbons, Mr. McLean, MAUI, and any other interested intervenors or experts. The
8 purpose of this workshop or collaborative should be to establish an agreed upon
9 standard when selecting common LED fixtures best suited for municipal
10 streetlighting customers served by DTE. This topic is one of critical importance
11 that involves public safety and should be handled in a forum in which expert,
12 intervenor, and Company perspectives can be shared freely without risk of being
13 taken out of context. Given the voluminous and technical information provided by
14 both myself and Witness Bunch in this proceeding, a technical workshop or joint
15 collaborative is exactly the venue necessary to drive toward a resolution, and reason
16 they exist. We owe it to our communities to get this right.

17

18 **Q42. Do you also recommend that the Commission reject the cumulative**
19 **disallowance of \$7.7M (including the \$5.8M already written down by the**
20 **Company as part of Commission order U-21297)?**

21 A42. Yes. As I have discussed above, the Commission adopted MI-MAUI's proposed
22 disallowance in its order U-21297 for which the sole basis was the Leotek crossover
23 chart. The chart is no longer supported by Leotek and has been removed.
24 Therefore, I recommend the Commission reject Witness Bunch's cumulative

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1 disallowance proposal under both of his methodologies, and instead order a
2 technical workshop or joint collaborative as I have also discussed above.

3

4 LED COST OF SERVICE AND IMPACTS ON HID TO LED CONVERSIONS

5 **Q43. Witness Bunch advocates for an end to “gradualism” which the Commission**
6 **approved in its Order in Case No. U-18014, and set rates to true cost of service.**
7 **Specifically, he states on page 70, lines 16 - 18 of his direct testimony, “gradual**
8 **adjustment has not worked as intended nor within a reasonable timeline, and**
9 **its perpetuation causes a subsidy of less-efficient lights by more-efficient**
10 **LEDs.” Do you agree?**

11 A43. As previously stated on page 7, lines 14-24 of my U-20836 rebuttal testimony, and
12 again on page 8, lines 1-7 of my U-21297 rebuttal testimony, I am not advocating
13 for a specific outcome. Instead, my intent is to provide information to the
14 Commission in making a prudent decision on whether to continue using the current
15 design methodology while considering the interests of all rate payers. The reality
16 is that moving to true cost-of-service would have a significant financial impact for
17 certain communities, many of whom are under financial constraints, who still have
18 a high concentration of HID fixtures in service.

19

20 **Q44. Do you believe there continues to robust and proactive adoption by municipal**
21 **customers in converting HIDs to LEDs?**

22 A44. Yes, I do. As evidenced by the data provided in Table 2 (Community Lighting
23 Assets by Lighting Type (2012-2023))⁴⁶ from my U-21534 direct testimony (table
24 provided below for convenience), there continues to be robust and proactive
25 conversions driven by municipalities themselves:

⁴⁶ Table 2, Direct Testimony of Robert Bellini, p8, line 15

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1 Community Lighting Assets by Lighting Type (2012-2023) Further, as I mentioned

Lighting Type	2012	2017	2023
Light Emitting Diode (LED)	2,851 (1%)	53,018 (27%)	124,565 (62%)
High Pressure Sodium (HPS)	98,070 (49%)	91,422 (46%)	53,374 (27%)
Mercury Vapor (MV)	94,681 (48%)	52,518 (26%)	19,895 (10%)
Metal Halide (MH)	2,977 (2%)	2,468 (1%)	1,622 (1%)
Total Assets	198,579	199,426	199,377

2 earlier, there will be another approximately 11,000 additional municipal
3 conversions of the remaining 52,000 municipal HIDs between 2024 – 2025.

4

5 **REBUTTAL OF ANN ARBOR WITNESSES NAHEEDY & STULTS**

6 **STREETLIGHT RELIABILITY**

7 **Q45. Witness Naheedy states in his direct testimony on page 2, line 17 that**
8 **“streetlight reliability continues to be a concern for Ann Arbor...” Do you**
9 **share in Witness Naheedy’s conclusion on page 3 lines 4 – 5 of his direct**
10 **testimony that based on his impression “DTE’s outage response is very similar**
11 **to past years?”**

12 **A45. No. As Mr. Naheedy admits, his impression of DTE’s performance was formed**
13 **based on testimony and data presented by his predecessor two years ago as part of**
14 **Case No. U-20836 stating that DTE-owned streetlights in Ann Arbor experienced**
15 **an average outage rate of approximately 26%.⁴⁷ The results cited from that data**
16 **are questionable as the Company has conducted 8 Ann Arbor night patrols from**
17 **2020 through 2023, with outage results ranging from 2% to 6% over that period.**

18

19 **Q46. Does the City of Ann Arbor maintain outage performance metrics such as**
20 **number of outages, average duration, or outage root causes?**

⁴⁷ Witness Naheedy U-21534 Direct Testimony, page 2, lines 20-21

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1 A46. No, they do not. As I discussed and highlighted in my rebuttal to Witness Bunch's
2 proposals specific to DTE being required to collect data beyond its OMS systems
3 capabilities, Ann Arbor, who has been piloting 75 network streetlighting nodes
4 (discussed below), does not maintain or have access to any such data.⁴⁸

5
6 **Q47. Is it your understanding that Ann Arbor deployed a networked lighting**
7 **control pilot inclusive of 75 nodes?**

8 A47. Yes. Approximately 2021, Ann Arbor deployed nodes on 75 City owned
9 streetlights. My understanding was the intent was to allow for immediate
10 notification of an outage, actual outage duration from inception of event to
11 restoration, and allow for some form of root cause analysis (i.e. fixture failure,
12 wiring failure, cable failure, etc.).

13
14 **Q48. Why would it be important for the Company to glean this outage information**
15 **from the results of the City's pilot?**

16 A48. This information would help compare and contrast outage results, help understand
17 the nature of outage causes, facilitate restoration of outages, and determine how the
18 collected data sent by the nodes have assisted in optimizing restoration cost and
19 performance.

20

21 ANN ARBOR HID-LED CONVERSION PROJECT – 58W LED 3000K CCT SAMPLE
22 SELECTION

23 **Q49. Witness Naheedy states on page 5, lines 7 – 15 of his direct testimony, that it**
24 **was important for the City's sampled LEDs (both 29W and 58W) they selected**

⁴⁸ Exhibit A-40 Schedule EE11 U-21534 DEAA-2.1bi – DEAA-2.1ci

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1 **for its conversion project to “meet lighting standard IES RP-8, have a**
2 **correlated color temperature no higher than 3000K” and that “none were**
3 **“standard offerings” from DTE.” Would the City’s sampled LEDs have met**
4 **IES RP-8 standards?**

5 A49. No, they would not have. ANSI/IES RP-8-22, section 10.3.4 titled “Spectral
6 Considerations” which notes a “practical difference for 4000K, which had greater
7 detection distances especially for pedestrians, than any of the other light sources.”
8 Therefore, our standard 58W LED fixture with a 4000K CCT is the only fixture
9 that would have aligned with ANSI/IES RP-8-22, while all of Ann Arbor’s sampled
10 lights would have not been in alignment.

11

12 ANN ARBOR POSITION ASSERTING THEY WERE FINANCIALLY
13 DISADVANTAGED BECAUSE REACTIVE HPS FAILURES ARE NOW REPLACED
14 WITH EQUIVALENT COMPANY LED FIXTURES

15 **Q50. Is Witness Naheedy correct in stating that, in reference to DTE now replacing**
16 **all HPS fixtures with LEDs, had the City waited for all the HPS fixtures to fail,**
17 **that the City would have had to pay no CIAC?⁴⁹**

18 A50. No, for two reasons. First, as discussed in the previous section, our standard stock
19 LED would not have been what the City selected for installation as part of their
20 conversion project and have clearly stated that the Company’s standard stock 58W
21 LED was not acceptable, and as such they would not want this fixture installed
22 under any scenario. Second, as I mentioned in my rebuttal to Witness Bunch on
23 this topic earlier, this methodology is consistent with how conversions are handled
24 during reactive maintenance for mercury vapor lights which we began converting

⁴⁹ Witness Naheedy U-21534 Direct Testimony, page 8, lines 2-5

Line
No.

1 and still do with equivalent LEDs. To the extent that a city decides to convert their
2 system to LEDs and have had MV or HPS lights replaced with equivalent LEDs
3 during reactive maintenance, those replaced lights would not be included as part of
4 the customers project costs, provided they don't want Company-installed standard
5 stock LEDs replaced.

6

7 ANN ARBOR BILL CREDIT PROPOSAL

8 **Q51. Do you agree with Witness Stults when she states in her direct testimony on**
9 **page 33, lines 2-5 that "Communities who proactively converted their**
10 **streetlights to LEDs and paid a CIAC up front should receive a credit so that**
11 **they are not paying both for the entirety of their own conversions and a portion**
12 **of others?"**

13 A51. No. In addition to the reasons I mentioned in response to Witness Naheedy's same
14 assertion above, there is no basis of fact in Witness Stults inference that Ann Arbor
15 or a similarly situated municipal customer wanting to convert to LEDs are both
16 paying for their own conversion as well as paying for a portion of others. Cost of
17 reactive conversions (including those performed in Ann Arbor) are socialized
18 among all municipalities, and municipal project conversion costs incurred to
19 convert a specific municipality's lights to LED are excluded from impacting all
20 other municipal customers (including Ann Arbor) that would otherwise be reflected
21 through higher rates. Lastly, Ann Arbor received a SEMCOG funded grant equal
22 to 80% of their total project HID-LED conversion costs.

23

24 **Q52. Does this conclude your rebuttal testimony?**

25 A52. Yes, it does.

1 JUDGE WALLACE: All right. That's it.

2 MS. REITZEL: That is it from me, your
3 Honor.

4 JUDGE WALLACE: That's it for you. Is
5 that it for the Company, or do we got more?

6 MS. REITZEL: I believe we are set.

7 MR. CHRISTINIDIS: I believe there's one
8 Vangilder exhibit that you may have misspoken,
9 Ms. Reitzel, and I want to say if you give me one second
10 here, we can clarify that. I believe for Vangilder, it's
11 Exhibit A-2 B1, you may have said B2 I think we heard.
12 So Exhibit A-2 Schedule B1 instead of B2. Can we take a
13 moment to clarify that?

14 MS. REITZEL: For, I do have B2 listed,
15 but I will confirm. Mr. Christinidis is correct, it
16 should be Exhibit A-2 Schedule B1. I apologize.

17 JUDGE WALLACE: All right. So with that,
18 you've got all the Company's witnesses and all the
19 Company's exhibits, at the very least the exhibits have
20 been moved; is that correct?

21 MR. CHRISTINIDIS: Yes, your Honor.

22 JUDGE WALLACE: All right. Then now at
23 this point, I'm going to admit Exhibits A-1 through A-6,
24 inclusive of all schedules, Exhibit A-11 through A-53,
25 inclusive of all schedules, plus Exhibit A-54. Am I

1 correct, there is no A-7, 8, 9, or 10; is that correct?
2 I pulled this off of the list of exhibits you sent me.

3 MR. CHRISTINIDIS: That sounds right,
4 your Honor.

5 JUDGE WALLACE: O.K. All right. And I
6 would note, then, that -- so A-1 through A-6, A-11
7 through A-53, A-54, by stipulation of the parties, I'll
8 note that a number of these exhibits, as discussed on the
9 record, have been revised and we have at least one
10 confidential schedule in the list that was provided, I
11 believe it was A-40 Schedule EE5, is that correct, that
12 is confidential, it is not available in the public
13 record.

14 All right. Thank you very much,
15 Mr. Christinidis, et al. And so we've got DTE bound in.
16 Let's go ahead with Mr. Abrams.

17 - - -

18 (Continued in Part 2.)

19 - - -