STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the Matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the the distribution and supply of electric energy, and for miscellaneous accounting authority.	)	Case No. U-21860

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on December 22, 2025.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before January 9, 2026, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before January 22, 2026.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sally L. Wallace

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December 22, 2025
Lansing, Michigan

Sally L. Wallace
Administrative Law Judge

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* * * * *

In the Matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the the distribution and supply of electric energy, and for miscellaneous accounting authority.	)	Case No. U-21860

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On April 24, 2025, DTE Electric Company (DTE or the Company) filed a rate application requesting a $574.1 million revenue increase, and other relief.[1] The rates requested in the application are based on a January 1 through December 31, 2026 projected test year; a January 1, 2024 through December 31, 2025 bridge period, and a 2023 historical year. The Company's application was accompanied by the testimony and exhibits of 34 witnesses. The most recent rate case order for DTE was issued by the Commission on January 23, 2025 in Case No. U-21534 (U-21534 order).

A protective order was entered on April 25, 2025, and, pursuant to due notice, Staff, DTE, and potential intervenors attended the May 22, 2025 prehearing conference.

[1] After various concessions, this amount was reduced to $562.2 million in the Company's reply brief, p. 3.

Intervention was granted to a total of 21 parties, some of whom participated collectively as noted: the Attorney General; City of Ann Arbor (Ann Arbor); Michigan Environmental Council (MEC), Citizens Utility Board (CUB), Natural Resources Defense Council (NRDC), Sierra Club (SC) (collectively, MNSC, MNC, CUB/NRDC or MNAG); Ecology Center, Union of Concerned Scientists, Environmental Law and Policy Center, Vote Solar (collectively, the Clean Energy Organizations (CEO)); Michigan Energy Innovation Business Council, Institute for Energy Innovation and Advanced Energy United (collectively, MEIU); Foundry Association of Michigan; Energy Michigan, Inc.; the Kroger Company (Kroger); Utility Workers Union of America, Local 223; Michigan Municipal Association for Utility Issues (MAUI), Michigan Coalition to Protect the Public Rights of Way (PROTEC) (together MAUI/PROTEC); Soulardarity, We Want Green, Too (together, the Detroit Area Advocacy Organizations or DAAO); Electrify America; Gerdau MacSteel, Inc.; Great Lakes Renewable Energy Association (GLREA); Walmart, Inc. (Walmart); Association of Businesses Advocating Tariff Equity (ABATE); International Transmission Company (ITC); and the Michigan Cable Telecommunications Association. The parties agreed to a schedule meeting the time limits of MCL 460.6a.

By the August 22, 2025 deadline, Staff and the following intervenors filed direct testimony and exhibits: Attorney General; CUB; MAUI/PROTEC; DAAO; Electrify America; MNC; Energy Michigan; Staff; Walmart; Ann Arbor; MNSC; ABATE; ITC; MEIU; MNAG; CUB/NRDC; and the CEO. By the September 22, 2025 filing deadline, DTE; Staff; DAAO; MEIU; ABATE; and Kroger filed rebuttal testimony.

At the evidentiary hearings held on September 24-26 and September 30, 2025, four witnesses appeared for cross-examination, while the testimony of the remaining

witnesses was bound into the record by agreement of the parties without the need for them to appear. The parties timely filed briefs and reply briefs in accordance with the established schedule.

As discussed in section II below, the record in this matter includes testimony from a total of 97 witnesses.

II.

OVERVIEW OF THE RECORD

The record in this case is comprised of approximately 5,319 transcript pages in five volumes plus a confidential transcript and numerous exhibits admitted into the record, several of which also have a confidential version. The following discussion is intended to give a general overview of the principal issues addressed by each witness. More detail on disputed issues is provided, as necessary, in the sections below.

A. DTE Electric

DTE presented the direct and rebuttal testimony of a total of 35 witnesses and Exhibits A-1 through A-6; Exhibits A-11 through A-48, and Exhibits A-50 through A-59, including numerous schedules included in several exhibits. As noted above, certain testimony and exhibits are designated confidential and are not available in the public record.

Joyce E. Leslie, Director, Regulatory Affairs for DTE Energy Corporate Services, LLC, introduced the Company's witnesses, and she discussed certain corporate memberships included in rates (focusing specifically on the Edison Electric Institute (EEI)), DTE's voluntary incentive separation plan (VSIP), and cost recovery for outage

credits.[2] Ms. Leslie's rebuttal testimony responded to recommendations on corporate memberships by the DAAO.

Marco A. Bruzzano, senior vice president, Regulatory Affairs, for DTE, provided: (1) an overview of the Company's method for projecting its revenue deficiency; (2) a summary of this rate case and purported customer benefits from DTE's proposed investments; and (3) he discussed the importance of timely cost recovery.[3] Mr. Bruzzano's rebuttal testimony addressed recommendations and adjustments by ABATE, the Attorney General, Staff, and CUB/NRDC.

Akarsh Sheilendranath, a Principal at the Brattle Group, testified on behalf of DTE, regarding how the under-recovery of capital expenditures purportedly affect the Company's regulatory, business, and financial risks.[4] Mr. Sheilendranath's rebuttal addresses certain claims and recommendations by MNC.

Kirk M. Vangilder, Principal Financial Analyst for DTE Energy Corporate Services, LLC, testified concerning the Company's historical revenue deficiency for the 2023 historical period.[5] Mr. Vangilder also provided support for DTE's projections for the test period as well as the incremental revenue requirement for the Company's alternative infrastructure recovery mechanism (IRM) proposals. Mr. Vangilder's rebuttal testimony addressed calculations of net rate base provided by Staff.

Theresa M. Uzenski, Manager of Regulatory Accounting for DTE Electric Company and DTE Gas Company at DTE Energy Corporate Services, LLC, testified

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[2] Ms. Leslie's qualifications, revised direct testimony, and rebuttal testimony are transcribed at 3 Tr 1016-1045.
[3] Mr. Bruzzano's qualifications, revised direct, and rebuttal testimony are transcribed at 3 Tr 964-1012.
[4] Mr. Sheilendranath's qualifications, direct, and rebuttal testimony are transcribed at 3 Tr 1049-1084.
[5] Mr. Vangilder's qualifications, direct testimony, and rebuttal testimony are transcribed at 3 Tr 1579-1607.

regarding the development of historical, bridge and test period financial statements, adjusted for ratemaking purposes.[6] Ms. Uzenski also supported capital expenditures and operations and maintenance (O&M) expense for the Corporate Staff Group area as well as various accounting treatments. Ms. Uzenski provided rebuttal testimony in response to Staff, the Attorney General, MNAG, and MNC.

John C. Robertson III, a Senior Manager in the Energy and Utilities practice for West Monroe Partners, LLC, testified regarding DTE's cost estimation procedures and interpretation thereof, the Association for the Advancement of Cost Engineering (AACE) cost estimate classifications used to support disallowances, and the role of contingency in cost estimation.[7]

Shawn D. Burgdorf, Manager of the Power Supply Strategy & Modeling team within DTE's Generation Optimization department, discussed the calculation of capacity-related generation costs that are part of power supply costs.[8] Mr. Burgdorf also discussed changes to the Midcontinent Independent System Operator (MISO) rules that may affect load modifying resources in the Company's portfolio. Mr. Burgdorf filed rebuttal testimony in response to Energy Michigan and Staff.

Jeffrey C. Davis, Expert - Nuclear Strategic Business Operations at DTE's Fermi 2 nuclear plant, testified regarding DTE's capital expenditures and O&M expenses for its nuclear operations at Fermi in the historical, bridge, and test periods.[9] In his rebuttal

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[6] Ms. Usenski's qualifications, revised direct testimony, and rebuttal testimony are transcribed at 4 Tr 2389-2515.
[7] Mr. Robertson's direct testimony is transcribed at 4 Tr 2081- 2104. As noted in his testimony, Mr. Robertson adopted the direct testimony and exhibits of DTE witness William H. Ludlow.
[8] Mr. Burgdorf's qualifications, direct and rebuttal testimony are transcribed at 4 Tr 2060-2078.
[9] Mr. Davis's qualifications, direct, and rebuttal testimony are transcribed at 3 Tr 416-533.

testimony, Mr. Davis addressed capital expenditure and O&M expense reductions proposed by the Attorney General.

Robert J. Lee, Manager of Environmental Strategy for DTE, discussed significant EPA regulations that affect the Company's currently operating and retired coal units.[10]

Ryan M. Stowe, Vice President of Reliability Operations for DTE, testified regarding the historical, bridge, and test period capital expenditures in the distribution strategic investment category of the infrastructure redesign and modernization programs proposed by DTE, including the 4.8 kilovolt (kV) and 8.3kV conversion programs; City of Detroit Infrastructure (CODI) conversion program; system loading projects; subtransmission redesign and rebuild (SRR) program; and the strategic undergrounding program.[11] Mr. Stowe provided rebuttal testimony in response to Staff, MNAG, the CEO, MNC, and ABATE witnesses as discussed below.

Jason D. De Stigter, Director of Utility Investment Planning in the Utility Consulting Practice of 1898 & Co. testified on behalf of DTE concerning the benefit cost analyses (BCAs) for (1) the pole and pole top maintenance and modernization (PTMM) program; (2) the strategic undergrounding pilot; (3) distribution automation; and (4) grid automation telecommunications.[12] Mr. De Stigter filed rebuttal testimony in response to MNAG, ABATE, the CEO, and Ann Arbor regarding the modeling and BCAs presented in this case.

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[10] Mr. Lee's direct testimony is transcribed at 3 Tr 1612-1633.
[11] Mr. Stowe's qualifications, revised direct, and rebuttal testimony are transcribed at 2 Tr 33-245. Portions of his rebuttal testimony, and some of his exhibits, are contained in the confidential record. Cross examination of Mr. Stowe begins at 2 Tr 246 and ends at 2 Tr 314.
[12] Mr. De Stigter's qualifications, direct testimony and rebuttal testimony are transcribed at 4 Tr 1836-1911. Portions of Mr. De Stigter's rebuttal testimony, and some of his exhibits, are confidential and are not contained in the public record.

Bill Chiu, Vice President of Distribution Engineering and Technology for DTE, provided a detailed overview of the Company's current distribution system and strategic investments planned for the system going forward.[13] Mr. Chiu provided rebuttal testimony in response to Staff, MNAG, ABATE, MNC, NRDC-CUB, the CEO and MAUI/PROTEC.

Joseph E. Robinson, Director of Distribution Operations Asset & Work Management for DTE, testified concerning the historical, bridge and test period capital expenditures and O&M expense for infrastructure resilience and hardening programs, including 4.8kV hardening, PTMM, preventative maintenance, and equipment replacement.[14] Mr. Robinson presented rebuttal testimony in response to recommendations or adjustments by MNAG, the Attorney General, the CEO, ABATE, and Ann Arbor.

Steven B. Ambrose, a Vice-President and the Chief Information Officer for DTE, testified regarding the Company's information technology (IT) planning, programs, and capital and O&M spending for the historical, bridge, and test periods.[15] Mr. Ambrose provided rebuttal testimony in response to Staff and the Attorney General on certain IT program adjustments.

Neal T. Foley, Director of Electric Marketing in the Electric Sales and Marketing organization of DTE, discussed the Company's transportation electrification plan (TEP) DTE's proposals concerning merchant fees, time-of-use (TOU) or time-of-day (TOD)

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[13] Mr. Chiu's qualifications, direct and rebuttal testimony are transcribed at 3 Tr 1087-1177.
[14] Mr. Robinson's qualifications, revised direct testimony, and rebuttal testimony are transcribed at 4 Tr 1915-2057.
[15] Mr. Ambrose's qualifications revised direct testimony and rebuttal testimony are transcribed at 4 Tr 2108-2384.

customer outreach expenses, and electric regulated marketing O&M expense.[16] Mr. Foley provided rebuttal in response to Staff, MEIU, the Attorney General, and NRDC/SC.

Aaron Willis, Director, Regulatory Affairs for DTE testified regarding power supply costs, residential rate design, the IRM (including surcharge design and proposed modifications to the IRM), and other tariff changes.[17] Mr. Willis provided rebuttal in response to recommendations made by Staff, MNC, the DAAO, ABATE, the CEO and MNAG.

Allen J. Kryscynski, Director of Distribution Operations Long Term Capital Planning and Regulatory Operations for DTE, presented an overview of the O&M spending proposed for the Company's distribution operations, including the use of the Global Prioritization Model (GPM) used for ranking projects and the incorporation of environmental justice (EJ) in investment decisions.[18] Mr. Kryscynski responded to issues raised and adjustments made by Staff, MNAG, the Attorney General, CUB/NRDC, MNC, the DAAO, and the CEO.

Markus B. Leuker, Director of Load Management and Forecasting in DTE's Business Planning and Development organization, provided the Company's current sales and a projection of maximum demand and system output for 2025-2029.[19] Mr. Leuker also addressed DTE's demand response (DR) programs, regulatory framework, and future DR investments. Mr. Leuker responded to issues raised by Staff, the Attorney General, MNSC, MNAG, MEIU, and Ann Arbor.

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[16] Mr. Foley's qualifications, direct, and rebuttal testimony are transcribed at 4 Tr 2612-2681.
[17] Mr. Willis's qualifications, direct testimony, and rebuttal testimony are transcribed at 4 Tr 1721- 1791. Cross examination of Mr. Willis begins at 4 Tr 1792 and ends at 4 Tr 1831.
[18] Mr. Kryscynski's qualifications, revised direct, and rebuttal testimony are transcribed at 3 Tr 1181-1295.
[19] Mr. Leuker's qualifications, direct, and rebuttal testimony are transcribed at 3 Tr 1300-1403.

Christopher J. Hartley, Business Development and Support Manager for Community Lighting for DTE, described the Company's community lighting assets, projected lighting sales, and projected capital and O&M spend in the test year.[20] In his rebuttal testimony, Mr. Hartley addressed recommendations by Staff and MAUI/PROTEC.

Timothy J. Lepczyk, Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Corporate Services, LLC, testified regarding the Company's proposed capital structure and short-term debt cost rate used in developing DTE's overall rate of return (ORR) in this case.[21] Mr. Lepczyk also provided rebuttal in response to Staff, the Attorney General, ABATE, MNAG, MNC, NRDC/CUB, and CUB.

Jennifer E. Nelson, a Vice President at Concentric Energy Advisors testified on behalf of DTE.[22] Ms. Nelson presented the Company's recommendation regarding its return on equity (ROE). Ms. Nelson also provided rebuttal testimony in response to Staff, the Attorney General, ABATE, CUB, Walmart, and MNC.

Matthew A. Fix, Director of Compensation and Retirement Income for DTE Energy Corporate Services, LLC, testified regarding the Company's compensation practices and costs, including labor inflation projections.[23] Mr. Fix's rebuttal addressed adjustments recommended by the Attorney General, ABATE, Staff, and CUB/NRDC.

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[20] Mr. Hartley's qualifications, revised direct testimony and rebuttal testimony are transcribed at 3 Tr 1407-1453.
[21] Mr. Lepczyk's qualifications, direct, and rebuttal testimony are transcribed at 4 Tr 2905-2936.
[22] Ms. Nelson's qualifications, direct testimony, and rebuttal testimony are transcribed at 4 Tr 2940-3125.
[23] Mr. Fix's qualifications, revised direct testimony and rebuttal testimony are transcribed at 3 Tr 1457-1522.

Margaret E. Guillaumin, Plant Director in DTE's Energy Supply organization, testified regarding the Company's capital investments and O&M expenses for (non-nuclear) steam power generation, Ludington Pumped Storage (Ludington), and battery energy storage systems (BESS) in the historical, bridge, and test periods.[24] Ms. Guillaumin's rebuttal testimony addressed certain adjustments by Staff, the Attorney General, and ABATE.

Brian L. Hill, Director Southwest Regional Customer Operations and Scheduling & Coordination for DTE, described the Company's base capital expenditures (historical, bridge and test period) for emergent needs such as storm and non-storm replacements, customer connections, and relocations.[25] Mr. Hill also discussed the Company's portable generator program for vulnerable customers. Mr. Hill presented rebuttal testimony in response to positions taken by the Attorney General, ABATE, Staff, MNC, and NRDC/CUB. He also presented surrebuttal testimony in response to the Attorney General.

David C. Milo, a Fuel Resources Specialist in the Operations and Logistics group within DTE's Fuel Supply department, testified regarding capital expenditures and O&M expense for fuel supply and Midwest Energy Resource Company (MERC) fuel handling for the historical, bridge, and test periods, including the planned retirement of MERC, as directed in the December 1, 2023 order in Case No. U-21297 (U-21297 order).[26] Mr. Milo's rebuttal addressed recommendations by MNAG concerning MERC O&M expense.

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[24] Ms. Guillaumin's qualifications, revised direct, and rebuttal testimony are transcribed at 3 Tr 537-710. Portions of her rebuttal testimony are confidential and thus not available in the public record.
[25] Mr. Hill's qualifications, direct testimony, rebuttal testimony, and surrebuttal testimony are transcribed at 4 Tr 2754-2841.
[26] Mr. Milo's qualifications, direct, and rebuttal testimony are transcribed at 3 Tr 713-736.

Stephen P. Rademacher, the Engineering Manager over Standards, New Technology, Interconnections and Distribution Operations NERC Compliance for DTE, testified regarding capital expenditures in the historical, bridge, and test periods for numerous technology and automation programs, including conservation voltage reduction (CVV) and volt-var optimization (VVO), certain BESS proposals, and grid management and enhancement programs.[27] Mr. Rademacher's rebuttal addressed recommended adjustments by MNAG, Staff, Ann Arbor, the CEO, and ABATE.

Timothy S. Lyons, a Partner with ScottMadden, Inc., testified on behalf of DTE. Mr. Lyons discussed the use of constant dollar averaging (CDA) in the development of the Company's forecasts.[28] Mr. Lyons submitted rebuttal testimony in response to Staff, the Attorney General, MNC, and ABATE.

Michael S. Cooper, Head of Total Rewards for DTE Energy Corporate Services, LLC, testified regarding the design, implementation, and administration of DTE's employee benefits and payroll.[29] Mr. Cooper's rebuttal and surrebuttal testimony addressed recommendations or adjustments proposed by Staff and the Attorney General.

Rachel Steudle, Director of Tree Trimming for DTE, testified regarding the progress made in the Company's tree-trimming program, including details on the tree-trimming "surge," customer benefits, and O&M expense for the historical and test periods.[30] Ms. Steudle also discussed vegetation management post-surge, and she

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[27] Mr. Rademacher's qualifications, revised direct, and rebuttal testimony are transcribed at 3 Tr 741-962.
[28] Mr. Lyons' qualifications, amended direct testimony, and rebuttal testimony are transcribed at 4 Tr 3160-3196.
[29] Mr. Cooper's qualifications, direct testimony, rebuttal testimony, and surrebuttal testimony are transcribed at 3 Tr 1525-1576.
[30] Ms. Steudle's qualifications, direct testimony, and rebuttal testimony are transcribed at 4 Tr 2845-2901.

presented rebuttal in response to Staff, the Attorney General, MNAG, NRDC/SC, and Ann Arbor.

Jason E. Sparks, Director of Revenue Management and Protection for DTE Energy Corporate Services, LLC, provided details concerning DTE's customer service O&M expense; the Company's low-income offerings, uncollectible expense, and details regarding notice of cash-only payment requirements.[31] Mr. Sparks presented rebuttal in response to recommendations and adjustments by the Attorney General, the DAAO, the CEO, and CUB.

Sherri L. Wisniewski, Director of Tax Operations for DTE Energy Corporate Services, LLC, discussed the Company's calculations of federal, state, local, and property tax expense and other tax expense.[32] She presented rebuttal in response to adjustments by the Attorney General and ABATE.

Quinn Gerdes, a Senior Strategist, Regulatory Affairs for DTE Energy Corporate Services, LLC, addressed forecast allocation schedules for the test year, and he presented an analysis on the transition of Rate Schedule D1.6 customers to Rate Schedule 9 D1.11.[33]

Rodrigo Cejas Goyanes, Consultant – Regulatory Economics in the Revenue Requirements Department of Regulatory Affairs for DTE Energy Corporate Services, LLC, presented the cost-of-service studies (COSS) for DTE.[34] Mr. Cejas Goyanes also

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[31] Mr. Sparks' qualifications, second revised direct testimony and rebuttal testimony are transcribed at 4 Tr 2684-2749.
[32] Ms. Wisniewski's qualifications, direct testimony, and rebuttal testimony are transcribed at 4 Tr 3129-3155.
[33] Mr. Gerdes' qualifications and direct testimony are transcribed at 4 Tr 2518-2537.
[34] Mr. Cejas Goyanes' qualifications, direct, and rebuttal testimony are transcribed at 4 Tr 2541-2577.

presented revenue requirement calculations for customer-related costs, state reliability mechanism (SRM) charge by customers class, and IRM charges by voltage class. Mr. Cejas Goyanes presented rebuttal in response to MNC and ABATE.

Anthony L. Turner, a Senior Strategist in Regulatory Affairs for DTE Energy Corporate Services, LLC, provided DTE's proposed rate design and certain tariff language modifications.[35] Mr. Turner presented rebuttal in response to recommendations by ABATE and Electrify America.

B. Commission Staff

Staff presented the testimony of a total of 30 witnesses and Exhibits S-1 through S-4 (with associated schedules); Exhibits S-6 and S-7 (with associated schedules); Exhibits S-8.0 through S-8.3; S-9.1 through S-9.4; S-10.1 through S-10.4; S-11.1 through S11.3; S-12.1 through S-12.12; S-13.1 through S-13.3; S-14.1, S-14.2; S-15.0 through S15.6; S-16.0; S-17.1 through S-17.17; S-18.0; S-19.1; S-20.1; S-21.0; S-22.0 through S-22.4; S-23; S-24.0 through S-24.6; S-25; S-26.0; S-27.0 through S-27.2; and S-28. Staff also filed a confidential exhibit.

Robert F. Nichols II, Manager of the Revenue Requirements Section of the Commission's Regulated Energy Division, presented Staff's projected revenue deficiency, projected net operating income, and projected Monroe regulatory asset return for DTE.[36]

Justin J. Hecht, an auditor in the Revenue Requirements section of the Commission's Regulated Energy Division, presented Staff's total projected rate base for

[35] Mr. Turner's qualifications, direct, and rebuttal testimony are transcribed at 4 Tr 2580-2608.
[36] Mr. Nichols qualifications and direct testimony are transcribed at 5 Tr 4876-4881.

the test year, and he supported adjustments to DTE's projected depreciation and amortization expense and property tax expense.[37]

Timothy G. Witt, an auditor in the Revenue Requirements Section of the Commission's Regulated Energy Division, sponsored Staff's projected test year working capital requirement for DTE.[38]

David W. Isakson, a Departmental Analyst in the Rates and Tariff Section of the Commission's Regulated Energy Division, presented Staff's present revenue, rate design and Staff's positions on certain rates, credits, and tariff provisions.[39] Specifically, Mr. Isakson addressed DR charges for Rate D1.1 and Rate D8, and he discussed modified language for S6.1 of DTE's tariff book, and the facilities allowance for Rate D13. Lastly, Mr. Isakson recommended certain changes to tariff sheet formatting in the Company's next rate case. Mr. Isakson also submitted rebuttal testimony in response to ABATE.

Michelle L. Schreur, Manager of the Income Analysis Unit in the Revenue Requirements section of the Commission's Regulated Energy Division, presented Staff's total O&M expense projection for the test year.[40]

Joseph E. Ufolla, a financial analyst in the Revenue Requirements Section of the Commission's Regulated Energy Division, presented Staff's recommendations concerning capital structure and cost rates.[41]

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[37] Mr. Hecht's qualifications and direct testimony are transcribed at 5 Tr 4884-4890.
[38] Mr. Witt's qualifications and direct testimony are transcribed at 5 Tr 4893-4896.
[39] Mr. Isakson's qualifications, direct testimony, and rebuttal testimony are transcribed at 5 Tr 4899-4923.
[40] Ms. Schreur's qualifications and direct testimony are transcribed at 5 Tr 4926-4928.
[41] Mr. Ufolla's qualifications and direct testimony are transcribed at 5 Tr 4931-4954.

Mark J. Pung, a Departmental Specialist (COSS) in the Rates and Tariff Section of the Regulated Energy Division, presented Staff's class COSS, Staff's recommended SRM capacity charge, customer charges, and allocator changes.[42]

Jay S. Gerken, Manager of the Rate Base Unit in the Revenue Requirements Section of the Commission's Regulated Energy Division, discussed the effect on revenues of DTE's alternative IRM proposals.[43]

Theresa L. McMillan-Sepkoski, an Audit Specialist in the Revenue Requirements Section of the Commission's Regulated Energy Division, presented Staff's recommendation on DTE's proposed employee incentive compensation plan (EICP) O&M expense and regulated marketing expense.[44] She also addressed the Company's accounting requests for deferral of merchant fees, a request for a regulatory liability for MERC costs, and the Company's request for a regulatory asset for the TEP rebate program.

Jing Shi, a Public Utilities Engineer in the Electric Operations Section in the Commission's Energy Operations Division, testified regarding Staff's review and recommended adjustments to the Company's strategic distribution capital expenditures.[45]

Jonathan J. DeCooman, a Public Utilities Engineering Specialist in the Resource Optimization and Certification Section of the Commission's Energy Resources Division, presented Staff's review and recommendations related to capital expenditures for the Trenton Channel BESS.[46]

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[42] Mr. Pung's qualifications and direct testimony are transcribed at 5 Tr 4957-4967.
[43] Mr. Gerken's qualifications and direct testimony are transcribed at 5 Tr 4970-4974.
[44] Ms. McMillan-Sepkoski's qualifications and direct testimony are transcribed at 5 Tr 4977-4988.
[45] Ms. Shi's qualifications and revised direct testimony are transcribed at 5 Tr 4991-5030.
[46] Mr. DeCooman's qualifications and direct testimony are transcribed at 5 Tr 5033-5042.

Danielle R. Rogers, a Departmental Analyst in the Data Access, Privacy, and IT Section of the Commission's Customer Assistance Division, presented Staff's position on the reasonableness and prudency of the Company's investments in IT programs.[47]

Cody S. Matthews, Manager of the Interconnection and Distributed Energy Resources Section of the Commission's Energy Operations Division, presented Staff's recommendations on DTE's proposed C&I BESS pilot.[48]

Lisa M. Kindschy, a Public Utilities Engineering Specialist in the Energy Cost Recovery & Generation Operations section within the Commission's Energy Operations Division, addressed O&M costs for steam power and other generation.[49] She also supported an increase to power supply expense resulting from Staff's sales forecast adjustment; and she supported adjustments to several O&M expense categories to incorporate Staff's inflation amounts.

Brittney Klocke, a Senior Analyst in the Data Access, Privacy and IT Section of the Commission's Customer Assistance Division, testified regarding Staff's recommendations and adjustments for certain IT programs in the Customer Experience and Operations area.[50]

Emma Zichi, an Analyst in the Data Access, Privacy and IT Section of the Commission's Customer Assistance Division, presented Staff's recommendations on DTE's proposed Information Protection Security capital expenditures for the bridge and test years, and O&M expenses.[51]

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[47] Ms. Rogers' qualifications and direct testimony are transcribed at 5 Tr 5045-5076.
[48] Mr. Matthews' qualifications and direct testimony are transcribed at 5 Tr 5079-5086.
[49] Ms. Kindschy's qualifications and direct testimony are transcribed at 5 Tr 5089-5108.
[50] Ms. Klocke's qualifications and direct testimony are transcribed at 5 Tr 5111-5128.
[51] Ms. Zichi's qualifications and direct testimony are transcribed at 5 Tr 5131-5135.

Ryan Boutet, a Public Utilities Engineer in the Electric Operations Section of the Commission's Energy Operations Division, provided Staff's review and recommendations related to the Company's infrastructure resilience and hardening programs, including PTMM, small wire replacement program, and cable replacement program.[52] Mr. Boutet provided rebuttal testimony in response to MNAG, ABATE, and the Attorney General.

Joshua S. Towslee, a Departmental Analyst in the Interconnection and Distributed Energy Resources Section within the Commission's Energy Operations Division, presented Staff's review and recommendations related to DTE's DR call center and suggested modifications to the DR approval and cost recovery framework.[53]

Hunter Hansen, a Public Utilities Engineer in the Data Access, Privacy & IT Section of the Commission's Customer Assistance Division, presented Staff's review and recommended adjustments to projected meters, the customer power status visibility project, EV fleet and maintenance and other miscellaneous.[54] Mr. Hunter also provided background on the Company's unregistered meters, contingency, and line loss factors.

Zachary S. Simmons, an Auditor in the Revenue Requirements Section of the Commission's Regulated Energy Division, presented Staff's recommendation regarding DTE's proposed courtyard space project.[55]

Shannon Rueckert, an auditor in the Revenue Requirements Section of the Commission's Regulated Energy Division, presented Staff's adjustment to the tree trimming regulatory asset. [56] Mr. Rueckert also addressed uncollectibles expense,

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[52] Mr. Boutet's qualifications, direct testimony, and rebuttal testimony are transcribed at 5 Tr 5138-5155.
[53] Mr. Towslee's qualifications and direct testimony are transcribed at 5 Tr 5158-5163.
[54] Mr. Hansen's qualifications and direct testimony are transcribed at 5 Tr 5166-5181.
[55] Mr. Simmon's qualifications and direct testimony are transcribed at 5 Tr 5184-5186.
[56] Mr. Rueckert's qualifications and amended direct testimony are transcribed at 5 Tr 5189-5198.

employee benefits, and administrative and general expenses. Lastly, Mr. Rueckert provided Staff's position on the Company's proposal to utilize the Department of Energy (DOE) 1706 loan program.

Allan David Freeman, an Assistant to the Division Director in the Commission's Energy Resources Division, presented Staff's review and recommendations related to DTE's TEP. [57] In rebuttal testimony, Mr. Freeman responded to NRDC/SC.

Elaina M. Braunschweig, a Departmental Analyst for the Rates and Tariff Section of the Commission's Regulated Energy Division, presented Staff's recommendations on allocation of low-income residential and senior citizen credits, as well as the payment stability plan revenue shortfall in the COSS.[58] Ms. Braunschweig presented rebuttal testimony in response to the DAAO concerning approval of a percentage of income payment plan (PIPP) and other modifications to DTE's energy assistance programs.

Paul R. Ausum, an Economic Analyst in the Resource Adequacy & Forecasting Section of the Commission's Energy Resources Division, presented recommended adjustments to DTE's forecast of deliveries, customer count, and peak demand used to design rates.[59] Mr. Ausum also recommended modifications to future filings by the Company including customer class level sales and customer counts.

Kevin S. Krause, a Gas Cost of Service Specialist within the Rates and Tariff Section of the Commission's Regulated Energy Division,[60] presented Staff's recommendations on EV rate design and tariffs, including the demand charge holiday,

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[57] Mr. Freeman's qualifications, direct and rebuttal testimony are transcribed at 5 Tr 5201-5212.
[58] Ms. Braunschweig's qualifications, direct, and rebuttal testimony are transcribed at 5 Tr 5215-5229.
[59] Mr. Ausum's qualifications and direct testimony are transcribed at 5 Tr 5232-5240.
[60] Mr. Krause's qualifications, direct testimony, and rebuttal testimony are transcribed at 5 Tr 5243-5253.

and TEP cost allocation. Mr. Krause also made recommendations for DTE's next rate concerning production cost allocation. Mr. Krause filed rebuttal testimony in response to TEP recommendations by ABATE and Walmart. Mr. Krause also addressed various rate and tariff proposals by the CEO, MEIU, and MNC.

Jessica Duell, a Public Utilities Departmental Analyst in the Electric Operations Section of the Commission's Energy Operations Division, presented Staff's recommendations regarding DTE's tree-trimming program and service restoration programs. [61]

Ally Durfee, a Public Utilities Engineer in the Electric Operations Section of the Commission's Energy Operations Division, presented Staff's positions on DTE's distribution base capital expenditures. [62]

Nicholas M. Evans, Manager of the Electric Operations Section of the Commission's Energy Operations Division, presented Staff's position on DTE's proposal concerning outage credits, and the Company's proposed changes to the IRM. [63] Mr. Evans filed rebuttal testimony in response to recommendations by ABATE, the CEO, and MNAG regarding the IRM.

Nicholas M. Revere, Director of the Energy Operations Division, presented Staff's position on the sales forecast to be used in calculating the Company's power supply cost recovery (PSCR) factor revenue forecast as an input to uncollectible expense.[64] Mr.

[61] Ms. Duell's qualifications and direct testimony are transcribed at 5 Tr 5256-5266.
[62] Ms. Durfee's qualifications and direct testimony are transcribed at 5 Tr 5269-5274.
[63] Mr. Evans' qualifications, direct testimony and rebuttal testimony are transcribed at 5 Tr 5277-5295.
[64] Mr. Revere's qualifications and direct testimony are transcribed at 5 Tr 5298-5306.

Revere also presented Staff's recommendation to reset the PSCR base in DTE's next rate case.

Anne T. Armstrong, Director of the Commission's Customer Service Division, presented rebuttal in response to the DAAO concerning shutoff protections.[65]

C. Attorney General

The Attorney General presented the testimony of one witness and Exhibits AG-1 through AG-19; AG-20 revised; AG-21 through AG-32, AG-34 through AG-60, AG-61 revised; and AG-62 through AG-93. This PFD notes that several of these exhibits have both public and confidential versions.

Sebastian Coppola, an independent business consultant with expertise in public utility and energy regulation, testified regarding adjustments to rate base, O&M expense, and cost of capital. [66]

D. Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), Citizens Utility Board (CUB) and Attorney General (AG)

In various configurations, MEC, NRDC, SC, CUB and the Attorney General presented a total of six witnesses and sponsored Exhibits MNAG-DS-1 through MNAG-DS-8; Exhibits MNAG-PA-1 through MNAG-PA-9; Exhibits CUB-1 through CUB-52; and Exhibits MEC-12, MEC-13, and MEC-15 through MEC-69.

Richard J. Bunch, a lead consultant at 5 Lakes Energy, LLC, testified on behalf of NRDC/CUB.[67] Mr. Bunch discussed the Company's residential electric rates compared to national and regional rates as well as energy burden, arrearages and customer

[65] Ms. Armstrong's qualifications and rebuttal testimony are transcribed at 5 Tr 5309-5318.
[66] Mr. Coppola's qualifications revised direct testimony are transcribed at 4 Tr 3413-3591.
[67] Mr. Bunch's qualifications and direct testimony are transcribed at 5 Tr 4822-4869.

disconnection levels. He also generally supported the findings and recommendations from the audit conducted by the Liberty Consulting Group (Liberty Audit), specifically addressing tree trimming recommendations, and he discussed the aggregate adjustments to capital expenditures and O&M expense proposed by other NRDC/CUB witnesses. Mr. Bunch recommended that DTE update its inflation rates and employee count and apply a productivity offset to its projected inflation rate for labor. He recommended adjustments to distribution operations capital investment and O&M expense, with certain amounts deferred for future securitization. Lastly, Mr. Bunch recommended that in its next rate case, DTE be required to present a BCA of its cash-only payment requirement to demonstrate that such practice does not increase arrears.

Dennis Stephens, an independent consultant specializing in electric and gas distribution operations, management, and performance measurement, testified on behalf of MEC, NRDC, and the Attorney General (MNAG).[68] Mr. Stephens testified regarding the Company's distribution capital spending proposed in this case. He specifically addressed: (1) distribution automation; (2) SRR proposals; (3) system loading projects; (4) the PTMM program; (5) certain circuit conversions; and (6) the strategic undergrounding pilot.

Paul J. Alvarez, who leads the Wired Group, a consultancy addressing the needs of consumer, environmental, and business advocates in state utility regulatory

[68] Mr. Stephens qualifications and direct testimony are transcribed at 5 Tr 4476-4545. Mr. Stephens also submitted a confidential version of his testimony. Cross examination of Mr. Stephens begins at 5 Tr 4546 and ends at 5 Tr 4589.

proceedings, testified on behalf of MEC, NRDC, and the Attorney General (MNAG).[69] Mr. Alvarez discussed findings from the Liberty Audit; his views on the Company's GPM and reliability models; DTE's BCA related to distribution automation, PTMM, and strategic undergrounding; grid telecommunications options; and the proposed extension of the IRM.

Matthew Bandyk, a Principal Associate at Synapse Energy Economics Inc., testified on behalf of CUB. Mr. Bandyk addressed cost of capital, including capital structure, ROE, and ORR for DTE.[70]

Douglas B. Jester, Managing Partner of 5 Lakes Energy, testified on behalf of MEC, NRDC, and CUB (MNC) regarding his recommendations to securitize the net book value of assets retired early due to distribution system conversions and costs associated with a distribution system "surge."[71] Mr. Jester also addressed O&M expense associated with MERC operations, and he responded to claims made by DTE concerning CDA and under-recovery of capital expenditures. Lastly, Mr. Jester discussed his recommendation that DTE transition to seasonal distribution rates.

Graham G Woolley, a Consultant at 5 Lakes Energy, testified on behalf of NRDC/SC in part, and MNSC in part.[72] On behalf of NRDC/SC, Mr. Woolley addressed several topics related to DTE's TEP including contribution in aid of construction (CIAC) for EV charging, the BCA for the Company's TEP, DTE's smart charge pilot and charging

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[69] Mr. Alvarez's qualifications and direct testimony are transcribed at 5 Tr 4596-4658. Portions of Mr. Alvarez's testimony are confidential. Cross examination and redirect of Mr. Alvarez begins at 5 Tr 4659 and ends at 5 Tr 4703.
[70] Mr. Bandyk's qualifications and direct testimony are transcribed at 5 Tr 4707-4744.
[71] Mr. Jester's qualifications and direct testimony are transcribed at 5 Tr 4748-4786.
[72] Mr. Woolley's qualifications and direct testimony are transcribed at 4 Tr 4790-4818.

hubs initiative. On behalf of MNSC, Mr. Woolley addressed the Company's transformer network capacity.

E. Association of Businesses Advocating Tariff Equity

ABATE presented the direct and rebuttal testimony of five witnesses, as well as Exhibits AB-1 through AB-28.

James R. Dauphinais, a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc., testified on behalf of ABATE regarding the use of projected test years and the proposed IRM and alternative.[73] Mr. Dauphinais also introduced ABATE's remaining witnesses.

Jessica A. York, a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc., testified on behalf of ABATE regarding production and distribution capital adjustments and incentive compensation and inflation adjustments to O&M expense.[74]

Colin T. Fitzhenry, a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc., testified on behalf of ABATE regarding the BCAs used by DTE to support the PTMM program, strategic undergrounding pilot, distribution automation, and grid automation telecommunications.[75]

Christopher C. Walters, a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc., testified on behalf of ABATE regarding the cost of capital, focusing specifically on capital structure and ROE.[76]

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[73] Mr. Dauphinais' qualifications and direct testimony are transcribed at 4 Tr 3378-3408.
[74] Ms. York's qualifications and direct testimony are transcribed at 4 Tr 3236-3269.
[75] Mr. Fitzhenry's qualifications and direct testimony are transcribed at 4 Tr 3354-3374.
[76] Mr. Walters' qualifications and direct testimony are transcribed at 4 Tr 3274-3350.

Brian C. Andrews, a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc., testified on behalf of ABATE regarding COSS, specifically concerning the allocation of TEP costs, as well as various rate design and tariff issues.[77] Mr. Andrews presented rebuttal testimony in response to Staff and MNC.

F. Soulardarity and We Want Green, Too (Detroit Area Advocacy Organizations (DAAO)

The DAAO sponsored the testimony of five witnesses and presented Exhibits DAO-1 through DAO-53; Exhibits DAO-101 through DAO-117; Exhibits DAO-201 through DAO-253; Exhibits DAO-301 through DAO-358; and Exhibits DAO-401 through DAO-486.

Shimekia Nichols, the Executive Director for Soulardarity, testified regarding issues in this rate case that may harm low-income and vulnerable customers, including recommendations to mitigate those harms.[78] Specifically, Ms. Nichols discussed energy affordability and the need to implement a percentage of income payment plan (PIPP) program; the Company's environmental justice (EJ) analysis and infrastructure investments; issues with TOU rates; and DTE's corporate memberships.

Toyia Watts, President of the Charlevoix Village Association, described her experiences as a DTE customer and made recommendations concerning energy affordability; DTE's assistance programs; shut off practices; outages; and the Company's communications and customer service.[79]

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[77] Mr. Andrews' qualifications, direct testimony, and rebuttal testimony are transcribed at 4 Tr 3205-3232.
[78] Ms. Nichols' qualifications and revised direct testimony are transcribed at 5 Tr 4102-4158.
[79] Ms. Watts' qualifications and direct testimony are transcribed at 5 Tr 4161-4192.

Dr. Yunus Kinkhabwala, a Senior Scientist with PSE Healthy Energy, discussed the impact that DTE's proposed revenue increase will have on residential customers, particularly low-income customers and customers in EJ communities.[80] He also discussed outage impacts, and made recommendations for alternatives for resilience for the Company's most vulnerable customers.

Elizabeth Jacob, Lead Staff Attorney at the Sugar Law Center for Economic and Social Justice, testified regarding her experiences as a legal services provider for residential customers of DTE, who are facing issues of affordability, including insufficiency of assistance programs; shutoffs, and high fees.[81] Ms. Jacobs submitted rebuttal testimony concerning merchant fees and the impacts of TOU rates on low-income customers.

Justin Schott, Director of the Energy Equity Project (EEP) and Lecturer of Energy Justice at the University of Michigan's School for Environment and Sustainability, discussed overall energy equity concerns of DTE residential customers, including energy insecurity, affordability, shutoffs, and assistance programs; issues with the Company's unregulated programs; and he made recommendations for improvements.[82]

G. Michigan Energy Innovations Business Council, Institute for Energy Innovation, and Advanced Energy United (MEIU)

MEIU presented the testimony of three witnesses and sponsored Exhibits MEIU-1.1 through MEIU-1.11; Exhibits MEIU-2.1 through MEIU-2.3; and Exhibits MEIU-3.1 through MEIU-3.4.

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[80] Dr. Kinkhabwala's qualifications and direct testimony are transcribed at 5 Tr 4195-4250.
[81] Ms. Jacob's qualifications, direct testimony, and rebuttal testimony are transcribed at 5 Tr 4253-4332.
[82] Mr. Schott's qualifications and direct testimony are transcribed at 5 Tr 4334-4439.

Sophia Schuster, a Policy Principal with MIEIBC and IEI, testified regarding DTE's EV forecast and TEP program offerings, including reallocation of funding between programs.[83] Ms. Schuster presented rebuttal testimony in response to Staff, ABATE, and the Attorney General.

Dr. Laura S. Sherman, President of MIEIBC and IEI, testified concerning DTE's proposed commercial and industrial (C&I) BESS pilot program.[84]

John D. Albers, a Director overseeing regulatory policy in the Midwest for Advanced Energy United, testified regarding the Company's efforts to acquire demand response (DR) resources as required under the settlement agreement in Case No. U-21193, DTE's most recent integrated resource plan (IRP) proceeding.[85] Mr. Albers also addressed DTE's concerns related to the lifting of the ban on aggregating DERs and the Company's plans for DERMS. Mr. Albers presented rebuttal testimony in support of testimony on VPPs provided by the CEO.

H. City of Ann Arbor

Ann Arbor presented the testimony of two witnesses and sponsored Exhibits AA-1 through AA-19.

Joseph Lange, a Senior Energy Analyst for the City of Ann Arbor, testified regarding the Company's proposed residential home generator program and the costs included for that program.[86]

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[83] Ms. Schuster's qualifications and direct and rebuttal testimony are transcribed at 5 Tr 3924-4021.
[84] Dr. Sherman's qualifications and direct testimony are transcribed at 5 Tr 4025-4042.
[85] Mr. Albers' qualifications, direct testimony, and rebuttal testimony are transcribed at 5 Tr 4046-4070.
[86] Mr. Lange's qualifications and direct testimony are transcribed at 4 Tr 3707-3712.

Dr. Melissa Stults, the Sustainability and Innovations Director for the City of Ann Arbor, made recommendations concerning DTE's proposals related to: (1) tree trimming; (2) distribution automation; (3) pole material cost increases; (4) demand response programs; and (5) communications and coordination with local government.[87]

I. The Clean Energy Organizations (CEO)

The CEO presented the testimony of three witnesses and Exhibits CEO-1 through CEO-35.

William D. Kenworthy, Senior Regulatory Director - Midwest for Vote Solar, testified regarding DTE's proposed distribution system investments, with a specific focus on the treatment of distributed energy resources (DERs), grid-edge technologies, including distributed energy resources management systems (DERMS), and customer programs.[88] Mr. Kenworthy also discussed and made recommendations concerning virtual power plants (VPPs) non-wires alternatives (NWAs), the transition of customers from Rate 1.6 to Rate D1.11, and he introduced the remaining CEO witnesses.

Curt Volkmann, President and founder of New Energy Advisors, LLC, testified on behalf of the CEO regarding the Company's distribution system and strategies and the BCAs related to the PTMM program, distribution automation, the SRR program, and the IRM proposals.[89]

Boratha Tan, Senior Regulatory Manager, Midwest for Vote Solar, provided analyses of the Company's distribution spending compared to other Midwest utilities, along with reliability data and increases to the producer price index (PPI).[90] Mr. Tan also

[87] Dr. Stultz's qualifications and direct testimony are transcribed at 4 Tr 3715-3739.
[88] Mr. Kenworthy's qualifications and direct testimony are transcribed at 4 Tr 3604-3637.
[89] Mr. Volkman's qualifications and direct testimony are transcribed at 4 Tr 3641-3672.
[90] Mr. Tan's qualifications and direct testimony are transcribed at 4 Tr 3676-3703.

presented an analysis of reliability and customer disconnections, making recommendations with respect to that topic.

J. Michigan Municipal Association for Utility Issues and the Michigan Coalition to Protect the Public Rights-of-Way (MAUI/PROTEC)

MAUI/PROTEC presented the testimony of one witness and sponsored Exhibits MAUI-1 through MAUI-16.

Pete Schultz, a Consultant at 5 Lakes Energy, LLC, made recommendations concerning DTE's streetlighting rate design and conversion of mercury vapor luminaires, streetlighting post inspection and cost recovery, and communication and coordination with local government on utility projects.[91]

K. Electrify America

Electrify America presented the testimony of one witness and sponsored Exhibit EA-1.

Jigar J. Shah, the Director of Energy Services for Electrify America, testified regarding DTE's proposed Rate D3.5 for Company-owned direct current fast charging (DCFC) pilot.[92]

L. Energy Michigan

Energy Michigan presented the testimony of one witness and sponsored Exhibits EM-1 through EM-8.

[91] Mr. Schultz's qualifications and direct testimony are transcribed at 4 Tr 3743-3770.
[92] Mr. Shah's qualifications and direct testimony are transcribed at 4 Tr 3595-3600.

Alexander J. Zakem, an independent consultant with experience in utility and energy matters, testified regarding DTE's state reliability mechanism (SRM) calculation and associated capacity charge, and he discussed the SRM true-up.[93]

M. Walmart

Walmart presented the testimony of one witness and sponsored Exhibits WAL-1 through WAL-4.

Matthew T. Lyon, Senior Manager, Utility Partnerships – Regulatory, for Walmart, Inc., testified regarding ROE, specifically customer impacts and national ROE trends.[94] Mr. Lyon also commented on the COSS production cost allocator, rate design for Rate D11, the IRM proposals, and EV charging rates.

N. Kroger

Kroger presented the rebuttal testimony of one witness.

Justin Bieber, a Principal for Energy Strategies, LLC, a consulting firm specialized in economic and policy analysis related to energy, provided rebuttal to ABATE on primary rate design.[95]

O. ITC Holdings

ITC presented the testimony of two witnesses.

Kevin Thompson, Director of System Protection & Control for ITC Holdings Corp., testified in support of DTE's proposal to prioritize the transformer high side protection

[93] Mr. Zakem's qualifications and direct testimony are transcribed at 5 Tr 3881-3919.
[94] Mr. Lyon's qualifications and direct testimony are transcribed at 5 Tr 4075-4099.
[95] Mr. Bieber's qualifications and rebuttal testimony are transcribed at 5 Tr 4442-4457.

program as part of the Company's SRR investments, with a focus on how DTE's investments in its subtransmission system impact the bulk electric system.[96]

Pushkar Chindhade, Principal Operations Engineer for ITC Holdings Corp., testified regarding the Company's plan to prioritize investments in blackstart resources.[97]

III.

LEGAL STANDARDS

Before addressing the disputes among the parties regarding other matters, it is appropriate to review the legal standards applicable in a rate case. The Commission applies the preponderance of the evidence standard when making findings of fact or weighing conflicting evidence.[98] The Commission is required to set rates that are just and reasonable when exercising its ratemaking authority.[99]

The rate-making process necessarily "involves a balancing of the investor and the consumer interests."[100] A public utility is constitutionally protected from being limited to rates that are so inadequate as to be confiscatory.[101] One of the factors relevant to the rate-setting process is the return a utility's investors may reasonably expect given the risk profile of public utilities as business enterprises.[102] The Commission has acknowledged

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[96] Mr. Thompson's qualifications and direct testimony are transcribed at 5 Tr 4459-4462.
[97] Mr. Chindhade's qualifications and direct testimony are transcribed at 5 Tr 4464-4467. Because no party disputed DTE's proposed investments in blackstart resources, this issue is not addressed further in this PFD.
[98] January 31, 2017, order, Case No. U-18014, p 8 (Rejecting a utility's request to apply the "substantial evidence" test and agreeing that the Commission utilizes the preponderance of the evidence standard).
[99] MCL 460.557(4).
[100] *Fed Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944).
[101] *ABATE v Pub Serv Comm*, 208 Mich App 248, 269; 527 NW2d 533 (1994).
[102] *Hope Natural Gas Co*, 320 US at 603; see also *Bluefield Water Works & Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679, 692-693; 43 S Ct 675, 679; 67 L Ed 1176 (1923).

that rates should be set so as to balance the interests of customers and shareholders such that the utility has "the opportunity to earn a reasonable return on its investments."[103]

In considering whether rates are just and reasonable, it is the result reached, and not the methods employed, that is controlling.[104] Further, the Commission has broad discretion in determining the appropriate amount of investment on which a return will be computed. For example, in discussing the Commission's predecessor agency, the Michigan Railroad Commission, the Michigan Supreme Court has held that "[w]hat return a public utility shall be entitled to earn upon its invested capital and what items shall be considered as properly going to make up the sum total of that invested capital are questions of fact for the determination of the commission[.]"[105] Additionally, ratemaking is a legislative function, and the Commission is not bound by any particular method or formula in the exercise this legislative function.[106]

Given the Commission's broad discretion in the rate-making process, and in the absence of any issues rising to the level of constitutional concern, this PFD will primarily look to past decisions of the Commission for guidance in determining how to resolve disputed issues involving rate case elements.

IV.

TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both

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[103] Case No. U-20561, May 8, 2020 Order, p 7.
[104] *Hope Natural Gas Co*, 320 US at 602; see also *Duquesne Light Co v Barasch*, 488 US 299, 310; 109 S Ct 609; 102 L Ed 2d 646 (1989); *Verizon Communications, Inc v FCC*, 535 US 467, 524–25; 122 S Ct 1646; 152 L Ed 2d 701 (2002).
[105] *City of Detroit v Michigan R Comm*, 209 Mich 395, 433; 177 NW 306 (1920).
[106] *ABATE v Pub Serv Comm*, 208 Mich App 248, 258; 527 NW2d 533 (1994); see also *Hope Natural Gas Co*, 320 US at 602.

the regulated utility and its customers. The Commission has explained that the selection of an appropriate test year has two components:

> First, a decision must be made regarding a 12-month period to be used for setting the utility's rates. A second determination must then be made regarding how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula. The Commission may use different methods in establishing values for these components, provided that the end result is a determination of just and reasonable rates for the company and its Customers.[107]

In developing its rates for this proceeding, DTE states that it relied on a projected test year from January 1 through December 31, 2026, explaining that in determining test year amounts the Company began with the 2023 historical year, normalized and adjusted for known and measurable changes.[108]

As he has in past rate cases, ABATE witness Dauphinais objected to DTE's use of a projected test year, testifying that based on past revenue deficiencies or revenue excess, DTE would not have been able to request such large rate increases absent the use of a projected test year.

Mr. Dauphinais described the adverse impacts to customers resulting from a projected test year, including: (1) customers experience rate increases sooner than they would with a historical test year; (2); projected test years have resulted in higher rates for customers than rates based on a historical test period; (3) DTE includes expense projections "that either DTE has not irrevocably committed to or otherwise can avoid if it finds it advantageous to do so to improve its realized rate of return for its shareholders;"

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[107] See January 11, 2010 order, Case No. U-15678, page 9.
[108] DTE Application, pp. 2-3.

and (4) Staff and intervenors are disadvantaged in reviewing the Company's application because the projections do not reflect actual expenditures and are "developed over many separate cost subaccounts and revenue categories," requiring additional time and resources, despite the reduced 10-month timeframe for completing the case.[109]

Next, Mr. Dauphinais addressed DTE's claim that its projected costs are based on known and measurable changes, opining that, "[k]nown and measurable changes are changes to costs that are inescapable and precisely identifiable in amount and timing. Future capital expenditures and projected expenses are often not inescapable, not precisely identifiable in amount and timing, or both."[110] Mr. Dauphinais discussed examples of known and measurable changes including normalization adjustments to address weather or economic volatility, annualization for costs associated with planned outages, and costs that are incurred in the later months of the historical period that are expected to continue at the same level going forward.[111]

Mr. Dauphinais further observed that the Commission is not required to set rates based on a projected test year, quoting the November 2, 2009 order in Case No. U-15645, p. 8-9, wherein the Commission discussed evidentiary presentations and standards and the utility's burden to substantiate its projections. As discussed in the order, in the absence of sufficient support, "the Commission may choose an alternative method for determining the projection." Mr. Dauphinais recommended that the alternative should be the use of a historical test year.[112]

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[109] 4 Tr 3389.
[110] 4 Tr 3390.
[111] *Id*.
[112] 4 Tr 3393.

Mr. Dauphinais presented Table JRD-3 at 4 Tr 3388, which demonstrates that in three of the last four rate cases, DTE had revenue sufficiencies of $80.5 million to $111.7 million, meaning that "in each of these historical test years (calendar years 2020, 2021 and 2022), DTE received revenues $80.6 to $111.7 million higher than necessary to earn its authorized rate of return during that historical test year, which totaled over the three years to approximately $285.8 million -- well in excess of the $150.5 million revenue deficiency DTE is reporting for its 2023 historical test year in this current proceeding."[113] He further noted that if the historical values reported by DTE were more closely scrutinized, they may contain costs that are not recoverable in rates, thus increasing the amount of excess earnings.

Based on this historical record of revenue sufficiencies, Mr. Dauphinais urged the Commission to be cautious to ensure:

> (i) that the projected expenses and investments included in DTE's projected test year are truly necessary to provide reliable electric service at the lowest reasonable cost; (ii) that DTE is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by DTE with respect to their amount and timing.[114]

In response, Mr. Bruzzano testified that the use of a projected test year is lawful and that the Commission has approved the use of projections since 2008, further noting that the Company disagrees with ABATE's claim that the Commission "is legally authorized" to reject a projected test year.[115] He also disputed Mr. Dauphinais' definition of known and measurable changes, stating that, "[t]he forward test year is a projection of

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[113] 4 Tr 3391.
[114] 4 Tr 3385.
[115] 4 Tr 1003.

the expenditures that are likely to be made given the information known at the time of the rate case filing."[116]

Mr. Bruzzano also countered Mr. Dauphinais' assertion that projected test years harm customers, testifying: "[u]nder a forward test year methodology, base rates are proposed for a future twelve-month period and, once approved by the Commission, go into effect no earlier than the start of that future period. As such, the implementation of new rates matches the projected costs approved by the Commission."[117] He added that basing rates on a historical year creates a mismatch between when costs are incurred and when they are recovered, resulting in regulatory lag that would impede the Company's ability to carry out its plans for investments intended to improve reliability.

As for projected test periods creating more problems in the review and auditing process, Mr. Bruzzano pointed to the Commission's most recent order adopting new rate case filing requirements that significantly increased the amount of detail required to support the Company's requests.[118]

MNAG witness Alvarez also discussed the problems with rate setting based on forward test years, noting that the use of projected test periods, and trackers like the IRM, reduce regulatory lag but also virtually eliminate the possibility of cost disallowance, thereby shifting financial risk from shareholders to ratepayers, and resulting in several additional unintended consequences.[119]

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[116] 3 Tr 1004.
[117] *Id*.
[118] 3 Tr 1006, citing the May 18, 2023 order in Case No. U-18238.
[119] 5 Tr 4648-5654. Mr. Alvarez's discussion of investment pre-approval is discussed in more detail, *supra* in the subsection addressing IRM proposals,

In its brief, ABATE reiterates that the use of projected test periods has "routinely" resulted in revenue excess. ABATE again urges the Commission to carefully scrutinize the Company's projections and use historical costs in cases where the Company failed to meet its burden to demonstrate that projected costs are reasonable and prudent.[120] ABATE also quoted and discussed comments criticizing projected test years submitted in Case No. U-21637, noting that in response to the Commission's query regarding whether a fully projected test year is in the interest of customers, "numerous entities representing myriad interests have explained in no uncertain terms that it does not."[121]

ABATE maintains that given DTE's track record of over-projecting costs, the Company's test year should be rejected in this case lest the Commission run afoul of its mandate to set just and reasonable rates. ABATE counters DTE's claim that projected test years address concerns regarding regulatory lag resulting from the use of historical periods, stating:

> This claim misses the point. The issue with projected test years is not that the projections cover the period in which the costs may be incurred, the issue is that they authorize recovery for hypothetical costs *before* they are incurred. In other words, the Company is authorized to collect revenue for costs it may never incur at all and thus customers pay higher rates than necessary for the Company to provide service. As demonstrated by DTE's three previous rate case filings this is not an idle concern, it is a consistent occurrence. The Company's argument regarding regulatory lag is therefore an argument that the Commission prioritize cost recovery expedience, rather than accuracy, and utility revenue security over accurate and affordable rates.[122]

ABATE concludes that if the Commission does consider projected costs as the basis for DTE's revenue requirement in this case, it should be more conscientious in

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[120] ABATE brief, 2.
[121] ABATE brief, 4.
[122] ABATE brief, 7, fn 5.

ensuring that the Company meets its burden to show that its projections are accurate, that the projects or programs it proposes are reasonable and prudent, and that the costs are certain to be incurred in the test period.[123]

DTE's brief reiterates that projected test years provide for timely recovery of costs that the Commission has reviewed and authorized, and, pointing to the May 18, 2023 order in Case No. U-18238 updating the rate case filing requirements, DTE maintains that it is mandated to provide detailed support for all of its projections in order to meet its burden of proof.

The parties' reply briefs do not raise any additional arguments.

While this PFD agrees that ABATE's concerns regarding the use of projections in establishing rates are significant and well-supported, the Commission has consistently determined that it is not unreasonable to use a projected test year to set rates for the period following the expected date of a Commission order. Addressing nearly identical arguments concerning the test period, in the U-21534 order, pp. 25-26, the Commission stated:

> MCL 460.6a(1) provides that "[a] utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." The statutory language plainly provides the utility with the opportunity to develop requested rates based on projected costs and revenues. It does not require the Commission to approve such requested rates. Thus, the Commission has rejected ABATE's arguments several times. See, e.g., November 18, 2022 order in Case No. U-20836, p. 8 (November 18 order); and December 1 order, p. 9. The Michigan Court of Appeals has twice affirmed the Commission on this issue. *In re Application of DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued December 21, 2021 (Docket No. U-353767); and *In re Application of DTE Electric Co to Increase Rates*, unpublished per curiam opinion of the Court of Appeals, issued February 25, 2021 (Docket Nos.

[123] ABATE brief, 9.

> 349924 and 350008). Nothing in the instant record persuades the Commission to deviate from those (and many other) prior rulings. The Commission will continue to evaluate every projection presented by the applicant utility for evidence of reasonableness and prudence and to rely on alternatives to the projected test year where appropriate.

As addressed in more detail below, the Commission has made clear that it is not required to accept those projections that it finds insufficiently supported or where it determines that there is a likelihood that the funds will not be spent as planned. If DTE fails to provide sufficient support, the Commission may disregard the projection, or it may employ some other means (such as a historical amount or average) to arrive at a reasonable and prudent amount.

V.

RATE BASE

A. Introduction

A utility's rate base is the value of the utility's property on which it is permitted to earn a specified rate of return. Rate base consists of the capital invested in used and useful plant, less accumulated depreciation, plus the utility's working capital requirements. In its application, DTE projected a total electric rate base of approximately $23.56 billion, adjusted to $23.53 billion in its brief. Staff projected a rate base of $23.17 billion in its initial brief.

Net plant is the primary component of rate base, and its key elements are total utility plant (plant in service, plant held for future use, and construction work in progress (CWIP)) less the depreciation reserve, which includes accumulated depreciation, amortization, and depletion.

However, before discussing disputed issues regarding the components of rate base, it is appropriate to note the Commission's standards for decision-making. As discussed above, a utility may use projected costs and revenues for a future test year when requesting an increase in rates, see MCL 460.6a(1), but the Commission has made clear that a utility must establish the credibility of its projections.[124] If a utility seeks approval for a projected cost, it must provide sufficient evidence to demonstrate that the specific project and its cost are reasonable and prudent, and it must also show by a preponderance of the evidence that the cost will actually be incurred before the end of the test period.[125] Further, if a utility fails to provide sufficient support for a particular item, then the Commission may choose an alternative method for determining the projection.[126]

Finally, it should be emphasized that an adjustment to the utility's projection for a particular item in this PFD is not necessarily the equivalent of a permanent disallowance of that expenditure. Rather, many adjustments made to capital expenditure items reflect a finding that the specific projected cost is currently not supported by sufficient evidence but could be recovered in a future case if adequately supported at that time.

Before addressing disputes over specific cost items, two issues must be addressed: (1) DTE's request for inclusion of contingency amounts in future rate cases;

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[124] See June 12, 2012 order in Case No. U-16794, p. 13 (Rejecting the argument that the Commission must necessarily accept a utility's projection and stating that a utility must supply the Commission with enough evidence to support a finding that the costs requested are just and reasonable).

[125] January 13, 2017 order in Case No. U-18014, pages 8-9 ("Moreover, in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test period.").

[126] January 11, 2010 order in Case No. U-15768, pages 9-10; see also September 8, 2016 Order, Case No. U-17895, page 4.

and (2) the Attorney General's and others' concerns regarding the significant increase in rate base over the past several years.

1. Contingency

DTE witness Robertson testified that while DTE has followed the Commission's directives by excluding contingency from the cost estimates in this proceeding, he recommended that in the future, the Commission "explicitly allow for the inclusion of contingency in cost allowances."[127] He stated that the use of contingency is considered a best practice and "a necessary component of project cost estimation" among industry associations; it is allowed by other jurisdictions, and it is used by some regulated utilities in cost forecasts for rate cases or similar regulatory proceedings.[128]

Relying on previous Commission orders, Staff witness Hansen disagreed that contingency should be allowed in the Company's next rate case. He noted that the Commission has been clear that contingency should not be recovered in rates because the forward nature of contingency cannot be evaluated for reasonableness and prudence. In fact, the Commission has consistently reasoned that reasonableness and prudence of contingency can only be evaluated when it is known – after an expense has been made and it is an actual cost.[129]

Neither the Company nor any intervening party addressed this issue in initial briefing. Staff's brief repeats Mr. Hansen's objections to allowing contingency in costs, noting that no party took issue with Staff's position in rebuttal.[130]

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[127] 4 Tr 2085-2086, 2103.
[128] 4 Tr 2099-2102.
[129] 5 Tr 5179-5180.
[130] Staff brief, 208.

The arguments made by Mr. Robertson regarding inclusion of contingency in cost recovery are not new. Although DTE appears to have abandoned this issue by failing to brief it, it is worth recognizing that Staff cited the Commission's order in Case No. U-20940 for the Commission's finding that actual costs incurred may be included in a subsequent rate case for a review of reasonableness and prudence, and potential recovery. Notably, the Company has filed rate cases on an annual basis for many years and there is no reason to believe that such a practice will not continue. Thus, the Company is at no articulated risk for delay in seeking recovery of actual costs incurred above those forecasted and approved for a project. This PFD, therefore, agrees with Staff that the Company has not presented a sufficient reason for the Commission to deviate from its now decade-long stance that contingency should be excluded from rate base, and DTE's proposal as outlined by Mr. Robertson should be rejected. [131]

2. Capital Expenditures and Increase in Rate Base

In this case, as has been raised in prior cases, several parties note the significant increase in rate base investments, particularly in distribution capital, without corresponding improvements in reliability. The Attorney General points to Table 1 of Mr. Coppola's testimony at 4 Tr 3423, which shows that until 2011, DTE was able to keep capital investments below $1 billion annually. However, for the bridge and test periods in this case, projected capital expenditures have tripled, increasing rate base by 11%, and more than doubling the size of DTE's rate base compared to a decade ago.[132]

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[131] See December 1, 2023 order in Case No. U-21297, p. 166 ("The Commission has repeatedly disallowed contingency in past rate cases."); November 18, 2022 order in Case No. U-20836, p. 199 (listing numerous Commission orders rejecting the use of contingency in rate cases).
[132] Attorney General brief, 11-12.

According to Mr. Coppola, some portion of this increased spending results from the need to replace aging infrastructure, but much of it "include[s] hundreds of millions of dollars in expensive automation projects, digital projects, a dizzying number of pilot projects, information technology projects, and office remodeling, all of which are unrelated or only tangentially related to fundamental infrastructure upgrades and serve mainly to increase rate base and customer costs without providing commensurate customer value."[133]

A second key driver of the increase in capital spending, according to Mr. Coppola, is the opportunity to increase earnings and shareprice for stockholders, as shown in Exhibit AG-1, a May 2025 Investor Presentation by DTE, which projects increases in earnings per share of 6%-8% through 2029, based largely on capital additions.

Although more specifically focused on distribution system investments, MNAG witness Alvarez similarly raises concerns about DTE's capital spending "[that] has skyrocketed in recent years" pointing to the costs requested for recovery in this rate case and the Company's 2023 Grid Distribution Plan that projects even greater capital spending.[134] Noting that both he and MNAG witness Stephens appreciate the Commission's concerns about safety and reliability, "we are also concerned about the impact of DTE's rapidly increasing capital spending on rates over the long term, the associated impact on Michigan's economy generally, and the associated impact on the state's low-income consumers specifically."[135] Further, Mr. Alvarez pointed out that DTE's capital investments have not led to significant improvements in reliability, presenting

[133] Attorney General brief, 12-13.
[134] 5 Tr 4599.
[135] 5 Tr 4599-4600.

Figure 2 at 5 Tr 4603, which shows system average interruption duration index (SAIDI), with and without major event days (MEDs, x-MEDs) for DTE, versus capital additions from 2014-2024. According to Mr. Alvarez:

> DTE claims its rates are reasonable, noting that requested rate increases are below inflation, and that DTE residential bills are below U.S. averages. While the Commission may look favorably upon such comparisons, what these comparisons lack is an indication of DTE's rapidly growing rate base. The rate base can be thought of as a liability that customers must repay. As it grows, customers' repayment liability grows. If customers are not getting reliability improvements from increases in their repayment liability, then why have previous Commissions allowed continuous and significant increases in customers' repayment liability? While the Commission is examining what customers are getting for their rate increases, I respectfully suggest that the Commission should also examine what customers are getting for the exceptional growth in DTE's rate base, as it represents a liability customers must re-pay. If the Commission holds rates steady while the size of the rate base skyrockets – and reliability is still not improving – customer interests are not being served.[136]

In her brief, the Attorney General relies on Mr. Coppola's testimony, reiterating that "[f]or a utility such as DTEE with limited sales and revenue growth, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base. The presentation is devoid of any discussion about sales or revenue growth to propel earnings growth at the utility."[137] As such, the Attorney General urges the Commission to be mindful of the significant increase in DTE's rate base in evaluating the Company's requests here, including special consideration of the burden annual rate increases impose on residential customers, especially those with fixed or low incomes.

This PFD acknowledges that the issues raised by the Attorney General and MNAG are of significant concern but nevertheless finds they are best addressed by scrutinizing

[136] 5 Tr 4603-4604.
[137] Attorney General brief, 13.

the Company's proposed investments to ensure that they are reasonable and prudent, including benefits that are demonstrated to exceed the costs, as this PFD endeavors to do. This PFD further notes that affordability issues are addressed in detail below.

In the following sections, this PFD discusses various specific issues raised in relation to the following program or cost categories: Production Plant (non-nuclear); MERC and Fuel Supply; Nuclear Plant (including fuel); Distribution (including constant dollar averaging, the Liberty Audit, and the various analytical approaches DTE used to support its spending); Community Lighting; Demand Side Management; Information Technology; Corporate Staff Group; and Charging Forward (DTE's TEP) as shown in Exhibit A-12, Schedule B5, lines 1-12. As also shown in that exhibit, DTE incurred total capital expenditures for the listed programs of $2.642 billion in the 2023 historical year, and it projected capital expenditures of $2.631 billion in 2024, $2.552 billion in 2025, and approximately $2.8 billion in the 2026 test year.[138]

B. Production Plant (non-nuclear)

DTE's non-nuclear production plant historical and projected capital expenses through the test year are shown in Exhibit A-12 Schedule B5.1, in the following categories: steam power generation, hydraulic power generation, other power generation, and MERC/fuel supply, which is addressed below. Schedule B5.1, page 1, line 10 shows 2023 historical spending on the first three of the categories totaling $450.04 million, estimated 2024 spending of $576.22 million, projected 2025 spending of $466 million, and projected test year spending of approximately $282 million. Steam, hydraulic, and other categories

[138] Exhibit A-12, Schedule B5, line 13.

are subdivided into routine and non-routine subcategories, and Schedule B5.1 also includes Monroe Regulatory Asset Expenditures. Specific disputes concerning various non-nuclear production plant projects are addressed below.

1. Trenton Channel Seawall and Greenway

Ms. Guillaumin summarized the Trenton Channel Power Plant decommissioning, with $36.5 million spent in 2024 to complete asbestos abatement, equipment removal, demolition completion, and the commencement of final site grading and soil remediation.[139] She added that DTE projects spending $7.5 million in 2025 to complete the decommissioning process with additional soil remediation and final site grading.[140] This does not appear to be contested.

However, as set forth in Exhibit A-12, Schedule B5.1, DTE is proposing $0.514 million in the bridge period, and $9.456 million for the test year, to restore the integrity of the seawall at the Trenton Channel Power Plant, and to install a pedestrian greenway path along the Detroit River.[141] Ms. Guillaumin indicated that $0.9 million was spent on engineering and design of the seawall, shoreline, and greenway path between 2023 to early 2025. For 2026, $9.5 million is projected to be spent to complete engineering, design, and construction of the seawall, as well as to complete the engineering and design of the greenway path.[142] The seawall expenditure incudes removal of deteriorated sheet piles, maintaining existing piles, and adding new piles along the Detroit River and Slocum Canals to prevent sloughing into, and contamination of, the two waterways. Ms.

[139] 3 Tr 578-579.
[140] 3 Tr 579.
[141] 4 Tr 3254.
[142] 3 Tr 580.

Guillaumin added that the construction of a pedestrian greenway path was agreed upon to secure issuance of the plant demolition permit from the City of Trenton, as well as to address concerns of the U.S. Army Corps of Engineers and EGLE.[143]

Ms. York opined that spending for the Trenton Channel Seawall should be excluded from rate base because the funds are not likely to be spent in the bridge period and test year.[144] In support, she cited the Commission's approved inclusion of $1.1 million for the Trenton Seawall in Case No. U-21534, and disallowance of $9.5 million until DTE could support the amounts requested with additional internal review and approval. Ms. York stated that the request in this case was identical to the one the Commission addressed in Case No. U-21534. She added that DTE's testimony did not include any indication that additional internal review or approval for the project had occurred, further adding that a discovery request showed negative $285,000 in capital spending on the project for January through May 2025.[145]

Mr. Coppola clarified in his testimony that the forecasted expense of the seawall project is $4.8 million for 2026; the greenway path has $4.6 million forecasted for 2026; the remainder ($2.6 million) of the total $7.2 million for the greenway path is to be incurred in 2027.[146] Like Ms. York, Mr. Coppola noted that the seawall and greenway projects had not yet received DTE internal approval, and he recommended removal of the $9,456,000

[143] 3 Tr 579-580.
[144] 4 Tr 3254-3255.
[145] 4 Tr 3254-3255, referencing Exhibit AB-7, pp. 25-31.
[146] 4 Tr 3458.

for 2026 from DTE's capital expenditures.[147] He opined that both projects were in the early stages of design and concluded that they were premature to include in rate base.[148]

Ms. Guillaumin testified in rebuttal that DTE had spent $0.9 million to support engineering and design work on the project, and full project completion is still set for 2027.[149] She reiterated that the existing seawall is at the end of its life and must be replaced to ensure the stability of the riverfront, again noting that construction of the pedestrian greenway path was part of the stipulated demolition permit for the Trenton Channel Power Plant from the City of Trenton.[150] She clarified that DTE had approved an appropriation request for $1.1 million for the project covering engineering and design of the future site, contending that the project is "progressing as planned and there is no reason to expect . . . [it] . . . will not be completed."[151] Ms. Guillaumin stated that an appropriation request for the full project budget would be executed upon completion of design and engineering, but that the project was necessary for both safety and to satisfy the permit requirements for the already demolished Trenton Channel Power Plant.[152]

ABATE takes this to mean that DTE has not followed the Commission's direction from Case No. U-21534, that was based on the same exhibit in that case as in this one, to seek approval of the $9.5 million declined in that case only after additional internal review and approval had taken place. As a result, "further cost recovery is unreasonable and baseless at this time."[153] ABATE notes that no documentation of internal review and

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[147] 4 Tr 3458.
[148] 4 Tr 3458.
[149] 3 Tr 708-709.
[150] 3 Tr 708-709.
[151] 3 Tr 709.
[152] 3 Tr 709.
[153] ABATE brief, 11.

approval has been provided, and that the documents that were provided in this case showed negative capital spending of $285,000 for January through May 2025.[154] Because DTE has not demonstrated that the proposed investment is likely to be made during the bridge period or projected test year, ABATE maintains that the requested recovery has not been demonstrated to be reasonable or prudent and should be denied.[155] ABATE's reply brief raises the same points.[156]

In her brief, the Attorney General emphasizes that project completion is outside the test year, and that the seawall and greenway are in early stages of design and development. Therefore, the forecasted expenses are highly speculative and unsupported. The Attorney General again recommends that $9,456,000 be disallowed for 2026, contending that recovery should only be permitted at a later date when costs are more certain.[157] She reaffirms this recommendation in her reply brief.[158]

DTE responds with most of the same rationale and facts set forth in Ms. Guillaumin's direct and rebuttal testimony, highlighting the copy of the approved $1.1 million appropriation request it provided in discovery, and again noting that the project is necessary to comply with the requirements for the decommissioning of the Trenton Channel Power Plant.[159] DTE's initial brief does not appear to directly address ABATE's assertion that the project had negative spending in the first five months of 2025. While DTE recognizes ABATE's argument regarding the negative spending in its reply brief, the

[154] ABATE brief, 11, citing Exhibit AB-7.
[155] ABATE brief, 10-11.
[156] ABATE reply, 5.
[157] Attorney General brief, 48-50.
[158] Attorney General reply, 16.
[159] DTE brief, 35-36, citing AB-8.

reply provides no new explanation, and it relies on the same arguments raised in its initial brief.[160]

The $1.1 million expenditure request in this case appears to match the $1.1 million that ABATE notes was approved in Case No. U-21534.[161] In that case, the Commission specifically concluded that, even for a project that "is likely to be carried out at some point," the projection had to be both objectively reasonable and likely to be carried out during the test year to be considered reasonable and prudent.[162] Based on this rationale, the Commission allowed recovery of the $1.1 million that had already received Company appropriations approval, but disallowed the remaining $9.8 million that had been projected for the 2025 test year.[163] Because this is a project that must be completed at some point, per the agreements between DTE and various governmental units related to the demolition of the Trenton Channel Power Plant, approving the $0.514 million requested for the bridge period seems reasonable to allow planning and engineering to continue. However, DTE has not provided the documentation of progress required by the Commission in U-21534 for approval of the remaining $9.456 million. Therefore, this PFD recommends disallowance of the $9.456 million test year expenditure because, lacking internal approvals, it is not likely to be spent during the test year.

2. Monroe Fly Ash Basin Closure

Ms. Guillaumin provided an overview of the Environmental Protection Agency (EPA) Steam Electric Effluent Limitation Guidelines (ELG) rule, and its impacts on coal-

[160] DTE reply, 20-21.
[161] ABATE brief, 10-11. January 23, 2025 order in Case No. U-21534, p. 52.
[162] January 23, 2025 order in Case No. U-21534, pp. 52-53.
[163] January 23, 2025 order in Case No. U-21534, pp. 51-53.

fired generation investments, including bottom ash transport water (BATW), flue gas desulfurization (FGD) wastewater, and fly ash transport water (FATW) limitations.[164] She noted that infrastructure for the dry transport of fly ash from Monroe Power Plant boilers was completed in 2023 in compliance with the FATW-portion of the ELG rule.[165] DTE spent $20.8 million on the fly ash handling systems in 2023, and $2.6 million for final site work in 2024.[166]

While the Monroe Power Plant fly ash basin ceased operations on December 29, 2023, its closure has continued with dewatering the approximately 400-acre pond, grading the existing 28 million cubic yards of fly ash, and installing an impervious synthetic membrane cover.[167] Ms. Guillaumin stated that, in 2023, $3.8 million was spent on engineering and design. She further stated that $4.8 million was spent in 2024 to continue engineering and design for the basin closure project, and for developing the RFP to effectuate basin closure. The RFP was issued in October 2024, with bids received in December 2024.[168]

Monroe Power Plant investments after January 1, 2025 will be recovered through a regulatory asset.[169] Ms. Guillaumin testified that, for 2025, expenditures of $13.9 million are projected, to award the ash basin closure construction contract, begin construction, establish a trailer and staging area, and procure a basin liner cap. She further testified that $107.8 million in spending is projected for 2026 for dewatering the 410-acre pond,

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[164] 3 Tr 541, 556-558.
[165] 3 Tr 558, 565.
[166] 3 Tr 565.
[167] 3 Tr 572-573.
[168] 3 Tr 573-574.
[169] 3 Tr 573, citing Exhibit A-12, Schedule B5.1, pp. 2, line 46.

mass grading, material delivery, and liner cap and synthetic turf installation. According to Ms. Guillaumin, closure of the Monroe Fly Ash Basin is anticipated to be completed by December 28, 2028 to comply with 40 CFR 257.102(f)(1).[170]

Mr. Lee testified similarly regarding the necessary steps for the basin's closure, adding that closure activities were "underway," and that closure construction would be "completed in phases and take a minimum of five years."[171] He also testified that the Company must complete closure within five years of commencing closure activities, with the possibility of up to five 2-year extensions. He added that the final receipt of waste at the basin occurred December 29, 2023.[172]

Mr. Coppola noted that the actual amount spent between 2021 and 2024 was $9.2 million, while $13,899,000 is forecasted for 2025, and $107,759,000 is projected for 2026 to be charged to the regulatory asset.[173] He interpreted DTE's position to be that the fly ash basin retirement will occur in two phases in 2028 and 2032, with the initial work having commenced in 2021. According to Mr. Coppola, the Attorney General requested details regarding the 2023 through 2026 capital spending on the basin closure, and requested a copy of the basin closure plan.[174] Mr. Coppola characterized what was provided in response as including "ballpark" cost estimates of $102 million for labor, $58 million for dewatering, and $43.6 million for earth moving, along with a 2023 version of the basin closure plan showing "wide ranges of dates for major tasks" "from 2024 to 2028 and

[170] 3 Tr 574.
[171] 3 Tr 1628-1629.
[172] 3 Tr 1631-1632.
[173] 4 Tr 3454.
[174] 4 Tr 3454.

completion in the second quarter of 2029."[175]

According to Mr. Coppola, DTE indicated that the plan is being updated, and that the approval for the capital expenditures had not yet been obtained from the DTE Board of Directors.[176] Mr. Coppola thought it possible that DTE might do some work on the project in 2025 or 2026, but, with the implementation plan still being finalized, and contractors not yet selected to perform the work, he found it unlikely that DTE would spend the forecasted $107,809,000 in 2026.[177] As a result, he recommended removal from the regulatory asset of at least half of the $107,809,000, approximately $53,880,000, for 2026 as a working capital adjustment.[178]

Ms. Guillaumin, in rebuttal, emphasized that the Monroe Fly Ash Basin Closure was necessary to comply with state and federal environmental regulations, noting from her initial testimony that the basin will be closed and will require "significant dewatering, grading, and capping efforts to meet regulatory requirements."[179] She indicated that management has approved the funds for the work to proceed in the ordinary course, opining that Mr. Coppola's recommended exclusion should be disregarded.[180] Nevertheless, she admitted that additional formal funding approvals would be "gained in the ordinary course to complete the required environmental rule-based work as the implementation plan is finalized, and contractors will be selected to perform the work."[181]

The Attorney General contends that "[w]hile the work may eventually be

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[175] 4 Tr 3454.
[176] 4 Tr 3454-3455.
[177] 4 Tr 3454-3455.
[178] 4 Tr 3455-3456.
[179] 3 Tr 707-708.
[180] 3 Tr 708.
[181] 3 Tr 708.

completed, there is no reason to jam all of the spending into this rate case and burden customers that much more, when the contractors have not even been identified and DTE does not have formal approval for all of the funding it seeks."[182] The brief reiterates Mr. Coppola's testimony that the project has not received fully approved capital spending from DTE's Board of Directors and that it is unlikely that all of the proposed spending will occur in 2025 and 2026. As a result, the Attorney General recommends that $53,880,000 be removed from the 2026 capital expenditures forecasted for the regulatory asset account, half of DTE's forecasted amount, which also results in a working capital adjustment.[183]

In its brief, DTE notes that it has approved funds to proceed with the work as scheduled, and that "additional formal funding approvals will be gained in the ordinary course to complete the required regulatory work as the implementation plan is finalized, and contractors" are chosen to perform the work.[184] DTE raises this and its earlier arguments in its reply brief, emphasizing the need for funding approval to support regulatory compliance.[185] The Attorney General's reply brief also offers no new insights, instead stressing that "the fact that contractors have not even been selected for this project yet should be disqualifying for recovering these projected costs."[186]

Without the selection of a contractor, and without the bulk of the necessary approvals for project spending, this PFD agrees with the Attorney General that it is unlikely that the Company will spend the bulk of the projected $107.8 million in 2026. Mr. Lee's testimony regarding the timeline for the project and closure of the fly ash basin,

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[182] Attorney General brief, 45-46.
[183] Attorney General brief, 46.
[184] DTE brief, 34-35.
[185] DTE reply, 18-20.
[186] Attorney General reply, 15.

bolster this conclusion. Ms. Guillaumin's rebuttal testimony, and DTE's brief, are insufficient to establish that all of the work projected to be performed will actually *be* performed during the test year. As a result, this PFD recommends disallowance of half of the proposed test year spending, $53,880,000, which is included as an adjustment to working capital.

3. Trenton Channel Battery Energy Storage System

Ms. Guillaumin testified that the Trenton Channel Energy Center 220 MW BESS, an 880 MWh lithium ion (Li-ion) battery project, is anticipated to commence operations in 2026.[187] In her initial testimony, she summarized Exhibit A-12, Schedule B5.1, page 2, line 38, that $5.3 million was spent to bid equipment, award a contract, and procure long lead materials in 2023; and that $103 million was spent to take delivery of major electrical equipment and begin construction in 2024. DTE forecasted $260.1 million in project spending for 2025 to take delivery of batteries and electrical collection equipment, and to complete construction of the substation and BESS electrical switchyard, with $41.4 million forecasted for final payments, commissioning, performance testing, and capacity testing in 2026.[188]

Mr. Coppola also reviewed Exhibit A-12, Schedule B5.1, noting the historical capital expenditures for the project, and the forecasted spending of $260,089,000 for 2025 and $41,350,000 for 2026.[189] He reported that, despite an initial project forecast of $409.7 million, DTE reduced this forecast in its discovery responses to $378.5 million, cutting spending for 2025 from $260,089,000 to $74,311,000, but also increasing the

[187] 3 Tr 546, 586.
[188] 3 Tr 586, citing Exhibit A-12, Schedule B5.1, p. 2, line 38.
[189] 4 Tr 3456.

2026 forecast to $195,175,000 from the initial $41,350,000.[190]

According to Mr. Coppola, additional discovery responses from the Company indicated that DTE had entered into a replacement contract with a new battery supplier after the original supplier filed for bankruptcy. He noted that the BESS equipment contract had been finalized, but three supporting contracts of $33,480,000 total for engineering and construction, owner engineering services, and test energy, were not finalized. Because of the project changes, the fact that there were multiple parties involved, the experimental nature of the technology, and the likelihood of additional delays, Mr. Coppola recommended that $33,480,000 be removed from 2026 forecasted capital expenditures.[191] When factoring in DTE's altered projections, he recommended disallowance of $185,778,000 from 2025 capital expenditures, and an increase of $120,345,000 for 2026, representing the $153,825,000 revised DTE forecast for 2026 minus the $33,480,000 disallowance Mr. Coppola recommended.[192]

Staff witness DeCooman similarly outlined the history of the Trenton Channel BESS, the updated commercial operations date (COD) for 2026, DTE's originally requested $409.8 million in forecasted capital expenditures, and the breakout of project costs found in Exhibit S-11.1.[193] And he remarked on the capital expenditures approved in Case Nos. U-21297 and U-21534, as well as the disallowances of expenses that had not yet been contracted at the time of those cases.[194] Mr. DeCooman also noted that DTE has executed another $11.2 million in contract labor, or $361.7 million when combined

[190] 4 Tr 3456.
[191] 4 Tr 3457.
[192] 4 Tr 3456-3457.
[193] 5 Tr 5037-5038.
[194] 5 Tr 5038-5039.

with other approved major contracts, representing approximately 95% of the overall proposed capital expenditure for contract labor.[195] Mr. DeCooman stated that there were a few remaining contracts that "were not finalized as of August 4, 2025: an extension of two existing contracts and costs associated with providing test energy for commissioning."[196] He noted that the Commission had previously approved major contracts for an ESA; an EPCA; and a TA, collectively representing roughly $334 million of the anticipated $423 million to $460 million in total project capital expenditures.[197]

According to Mr. DeCooman, Staff audited the contract with the new battery supplier on August 4, 2025, which DTE entered into after the original contracted battery supplier, Powin, LLC, filed for Chapter 11 bankruptcy on June 9, 2025, and DTE canceled that contract. The new agreement pushed the Trenton BESS COD to December 2026 in this case, but it reduced the overall projected costs from $409.6 million to $378.5 million.[198] As a result of the signed battery supply contract and the reduction in the forecasted capital expenditures, Mr. DeCooman conveyed Staff's recommendation that "the Company provide all of the revenue deficiency impacts in rebuttal, so parties and the Commission may understand how this update in costs would impact the Company's requested relief."[199]

In her rebuttal, Ms. Guillaumin identified two parts of Mr. Coppola's proposed $64.7 million reduction: $31.2 million for the revised project forecast, and $33.5 million in relation

[195] 5 Tr 5038-5039.
[196] 5 Tr 5039.
[197] 5 Tr 5040.
[198] 5 Tr 5040-5041.
[199] 5 Tr 5041.

to contracts that have not yet been finalized.[200] She agreed that the proposed $31.2 million reduction was reasonable, commenting that Mr. Vangilder calculated the revenue deficiency impact as requested by Staff, and that this was presented in his rebuttal testimony.[201] However, in relation to the $33.5 million for contracts that had not yet been finalized, Ms. Guillaumin explained the sources of these expenditures, including continuation of engineering and construction services, which themselves included updated design, field modifications and schedule changes and incident changes to construction methods; continuation of engineering services; and test energy for commissioning the project.[202] Mr. Vangilder, in turn, reaffirmed that the project would be placed in service during 2026, adding the revenue deficiency impacts of the project.[203]

Staff's brief recommends that the Trenton Channel BESS expenditure be reduced by $31.953 million, with $31.2 million of this matching the reduced price of the new battery supply contract and supported by Ms. Guillaumin's rebuttal testimony.[204] Staff also agrees that the rate impact of $2.7 million proposed by DTE and reflected in Exhibit A-56 is reasonable.[205] However, in relation to Mr. Coppola's recommendation for an additional $33.48 million disallowance for contracts not yet finalized, Staff now agrees with Ms. Guillaumin's rebuttal testimony that the $33.48 million for unsigned contractual work is, based on her explanation, a continuation of existing contractual work necessary to complete the project. Staff thus finds the $33.48 million for unsigned contractual work to

[200] 3 Tr 696.
[201] 3 Tr 696, 698.
[202] 3 Tr 697-698; 3 Tr 1675 (Confidential)
[203] 3 Tr 1606-1607.
[204] Staff brief, 12-14.
[205] Staff brief, 12-13.

be reasonable, recommends that the Attorney General's additional disallowance be disregarded, and further recommends that the updated revenue deficiency in Exhibit A-56 be adopted.[206]

The Attorney General's brief initially notes that the Company agrees that a $31.2 million reduction is reasonable.[207] The Attorney General also characterizes Ms. Guillaumin's rebuttal testimony as supporting Mr. Coppola's additional proposed reduction, asserting that the scope and cost projection changes outlined by Ms. Guillaumin necessarily mean that the costs are premature.[208] As a result of the forecasted changes, the Attorney General recommends a decrease of $185,778,000 in 2025 capital expenditures, and an increase of $120,345,000 in 2026 capital expenditures.[209]

In its brief, DTE summarizes the parties' testimony and appears to agree with the $31.2 million proposed reduction in forecasted capital expenditures. The Company reiterates that Mr. Coppola's proposed disallowance of an additional $33,480,000 should be rejected because those expenditures are necessary to complete the project.[210] Additionally, based on Ms. Guillaumin's updated testimony regarding additional reduced expenses, the Company appears to agree to a higher reduction in the confidential version of its initial brief.[211]

However, in its reply brief, DTE references only a reduction of $31.2 million, and again urges the Commission to reject the Attorney General's additional recommendation

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[206] Staff brief, 13-14.
[207] Attorney General brief, 46-47.
[208] Attorney General brief, 47-48.
[209] Attorney General brief, 48.
[210] DTE brief, 32-34.
[211] CONF DTE brief, 33.

to disallow $33.48 million.[212] The Attorney General, in her reply brief, continues to advocate for the removal of the full $64.7 million in relation to the Trenton Channel BESS project, plus the additional amount of reduced expenditures appearing in DTE's reply.[213]

The parties appear to agree that DTE's currently forecasted capital expenditures for the Trenton Channel BESS project are substantially lower than what was requested initially. Reviewing Exhibit S-11.3, the updated Trenton Channel BESS schedule and cost breakdown, this PFD adopts the agreed upon disallowance of $31.2 million in capital expenditures that will no longer be incurred due to the change in battery supplier for the project. This PFD further recommends a downward adjustment, based on Ms. Guillaumin's confidential rebuttal testimony and DTE's confidential brief, that should be incorporated into the final revenue requirement.[214]

4. Slocum Battery Energy Storage System

Ms. Guillaumin testified that the Slocum BESS has a rating of 14 MW, and is a 56 MWh Li-ion BESS projected to be completed in 2025.[215] The Slocum Battery Pilot is intended to replace the diesel fueled peakers at the existing Slocum peaker site, and to store excess energy generated on the grid during off-peak hours for dispatch during peak hours.[216] Ms. Guillaumin indicated that $10.1 million was spent in 2023 to finish engineering, continue procurement of materials, complete the construction bid package, issue an RFP, and to award the construction contract while the existing diesel peakers and their supporting equipment were decommissioned and removed. She then indicated

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[212] DTE reply, 18.
[213] CONF Attorney General reply, 13-15.
[214] CONF DTE brief, 33.
[215] 3 Tr 545-546, 585.
[216] 3 Tr 585.

that $26.3 million was spent on BESS installation in 2024, and $0.7 million was projected for final project closeout costs in 2025, with commercial operations having started in February 2025.[217]

Mr. Coppola noted that in response to discovery, DTE provided a table demonstrating that the Slocum BESS project cost $10.4 million more than the originally estimated $34.7 million, with $6.0 million attributed to higher lithium prices, $2.7 million to higher labor costs, $0.9 million for additional engineering and design, and $1.4 million for higher overhead costs; only electrical infrastructure came in slightly lower than initially forecast.[218] Mr. Coppola opined that DTE never provided a BCA for the project, and did not disclose escalating costs or demonstrate that it was taking corrective action. As a result, Mr. Coppola recommended a disallowance of $5.0 million, to split the cost of the overruns between DTE and its customers, with $4,345,000 to be removed from 2024, and $655,000 to be removed from 2025, to hold DTE accountable for the 30% cost overrun.[219]

In response to Mr. Coppola's claims regarding a lack of disclosure, Ms. Guillaumin noted that in Case No. U-21534, she testified that the project costs had increased to $44.7 million, mainly due to increased lithium costs and the actual construction bids received, and supporting discovery was provided. According to her, the Commission approved all but "$2 million related to uncertainty in overheads on the project."[220] Ms. Guillaumin also stated that the Attorney General's request for disallowance based on an insufficient BCA was rejected in Case No. U-21297. And she pointed to Staff's findings regarding the value

[217] 3 Tr 585.
[218] 4 Tr 3459.
[219] 4 Tr 3459-3460.
[220] 3 Tr 704-705.

of the pilot in Case No. U-20836, indicating that the BESS was expected to produce approximately 20,000 MWh of energy annually, and that the retirement of diesel-fired peaking units at Slocum would have positive emissions and environmental impact.[221] Ms. Guillaumin maintained that Mr. Coppola's recommendations failed to consider information presented, and matters decided, in prior rate cases. She concluded that the cost increases and justification for the Slocum BESS have been considered fully, providing certainty for DTE, its contractors, and local municipalities.[222]

The Attorney General discounts Ms. Guillaumin's rebuttal, contending that project cost overruns of 30% above original projections are a "tremendous variance" that "should be held against the Company," irrespective of updates that DTE provided over the course of annual rate cases.[223] The Attorney General again highlights that no BCA was performed, and that DTE pointed only to competitive bidding when asked what corrective action the Company had taken to minimize cost overruns.[224] She also repeats her assertion that DTE must be held accountable for the cost overruns and maintains her recommended disallowances of $4,345,000 for 2024 and $655,000 for 2025.[225]

DTE responds by summarizing Ms. Guillaumin's testimony and the total projected expenditures of $45.1 million to complete the project, emphasizing that increased lithium prices and actual construction bids received were the primary drivers for the actual project costs exceeding initial projections.[226] The BESS was placed in service in February 2025,

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[221] 3 Tr 705.
[222] 3 Tr 706.
[223] Attorney General brief, 50.
[224] Attorney General brief, 51.
[225] Attorney General brief, 51-52.
[226] DTE brief, 31-32.

storing excess, off-peak energy from the grid for peak-hour dispatch, and, DTE contends, the project has provided valuable information to DTE, contractors, and municipalities in planning upcoming BESS projects.[227] DTE takes the position that the Attorney General has not demonstrated that any costs incurred were unreasonable or imprudent, that she provides no legal basis for disallowing any cost increases, and that she ignores Commission approval of the bulk of the contested expenses in prior cases.[228]

DTE's reply brief repeats the same arguments, highlighting that it is not clear, given the worldwide increase in lithium prices and the competitive bidding process used throughout the project, for what the Attorney General wishes to hold the Company accountable.[229] In her reply, the Attorney General asserts that she has not ignored prior cases, instead asserting that the prior case history is one of "continually escalating costs."[230] She reiterates her recommendation for a 50% cost overrun reduction, arguing that allowance of the full amount provides "no incentive for DTE to control costs on future projects."[231]

Although DTE incorrectly asserts in its briefing that any other party bears the burden of proving a lack of prudence or lack of reasonableness in the Company's incurred costs, DTE's explanation of the project, and the reasons for actual costs exceeding initial estimates, has merit. The $26.3 million spent in 2024, and the projected $0.7 million requested for project completion costs for 2025, are facially reasonable. And DTE is correct in arguing that no party has provided a factual or legal basis for disallowing project

[227] DTE brief, 31-32.
[228] DTE brief, 32.
[229] DTE reply, 15-17.
[230] Attorney General reply, 12-13.
[231] Attorney General reply, 12-13.

expenses previously approved by the Commission. This PFD recommends approval of the requested expense.

5. Blue Water Energy Center Kiewit Final Payment

Ms. Guillaumin briefly stated that, in relation to BWEC, the Company spent $0.3 million for project closeout activities, and the Company projects a $6.0 million expenditure for the "final milestone payment to Kiewit."[232] She highlighted that DTE forecasts total project capital expenditures of $946.8 million for the project, which is less than the $951.8 million approved in Case No. U-18419.[233]

Based on discovery responses from DTE, the Attorney General understood the $6.0 million payment to be the final contractually required payment to Kiewit, the main contractor for BWEC, for BWEC's completion.[234] Mr. Coppola took issue with the payment, given work quality problems as evidenced, he explained, by the power replacement costs from outages to replace faulty equipment and remediate construction problems.[235] He noted that DTE has proposed more than $85 million in capital expenditures in this case to repair, upgrade, and overhaul transformers, water pumps, heaters and controls, steam turbine valves, and turbine hot gas paths despite the fact that the plant commenced commercial operation in 2022.[236] Mr. Coppola opined that DTE had not addressed the "construction deficiencies," or held Kiewit accountable for poor performance. As a result, he recommended disallowance of the $6.0 million payment from

[232] 3 Tr 581. 4 Tr 3460.
[233] 3 Tr 581.
[234] 4 Tr 3460-3461.
[235] 4 Tr 3461.
[236] 4 Tr 3460-3461.

the 2025 forecasted capital expenditures.[237] Mr. Coppola also recommended that the Commission direct DTE "to fully document and justify in the next rate case" the large capital expenditures needed for a relatively new plant.[238]

Ms. Guillaumin responded that the final payment is contractually required to complete the project, and that resolving punch list items and equipment modifications to maximize performance and reliability are part of normal project completion.[239] She stated that BWEC has generated more than 26,000 GWh since June 2022.[240] In relation to Mr. Coppola's recommendation that all BWEC capital expenditures be documented and justified, Ms. Guillaumin opined that this was already done in the ordinary course of the rate case, that sufficient evidence had been provided for all BWEC capital expenditures, and that, because BWEC is fully operational, and its total construction cost was below that approved by the Commission in 2018, the Commission should reject Mr. Coppola's suggested disallowance.[241]

In her brief, the Attorney General adopts Mr. Coppola's testimony and asserts that the cost of bringing BWEC online, plus the $84 million in repairs, upgrades, and overhauls at BWEC in this case, represent a pattern of problems for the relatively new plant that is unreasonable, irrespective of whether initial costs were below those projected.[242] She maintains that Kiewit and other contractors should be held accountable for the problems at the new plant, and that DTE has not adequately addressed "the construction

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[237] 4 Tr 3461-3462.
[238] 4 Tr 3462.
[239] 3 Tr 702-703.
[240] 3 Tr 702.
[241] 3 Tr 702-703.
[242] Attorney General brief, 52-53.

deficiencies and the need to undertake additional capital expenditures." As a result, the Attorney General again recommends disallowance of the $6.0 million payment to Kiewit, and she repeats her request that DTE "fully document and justify in the next rate case why there is a need to undertake large capital expenditures" for a plant in operation for less than four years.[243]

DTE counters with the same points raised by Ms. Guillaumin in her testimony, emphasizing that the total projected capital expenditures for the project of $946.8 million is less than the $951.8 million approved by the Commission in Case No. U-18419.[244] The Company also stresses the normalcy of having completion items and equipment modifications in the operation of a new generating plant, and the information that DTE already provides regarding the costs and expenses involved with BWEC. As a result, DTE sums up that the Commission should reject the Attorney General's recommendations.[245] DTE raises the same points in its reply brief and characterizes the costs the Attorney General paints as construction performance problems as routine.[246]

In her reply brief, the Attorney General adopts the points made in testimony and her original brief. She adds that DTE's arguments in relation to BWEC coming in under budget should be disregarded, as projected costs have a high level of uncertainty and DTE continues to carry "the burden of showing that its actions and decisions were reasonable."[247] She then reiterates her concerns about $84 million in capital expenditures for a plant three years in service, and that this necessarily indicates that contractors and

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[243] Attorney General brief, 53.
[244] DTE brief, 36-37.
[245] DTE brief, 37.
[246] DTE reply, 21-22.
[247] Attorney General reply, 16-17.

others who had oversight should bear the cost of these "repairs."[248] And she repeats her request for additional documentation regarding the need for large capital expenditures at a plant that is still very new.[249]

Although the Attorney General's vigilance regarding BWEC, and the costs incident thereto, is commendable, the $6.0 million final payment to Kiewit does not appear to be unreasonable; thus, this PFD recommends authorizing the expenditure. Nevertheless, while the information provided in the ordinary course of the average rate case is generally sufficient to establish the reasonableness of expenses, given the close call in this case regarding some of the BWEC expenditures, while it is still a new plant, the Company should pay particular attention to mproviding the justification for any extraordinary expenses sought for the BWEC going forward.

6. Routine Projects

Mr. Coppola recommended the removal of five routine projects totaling $63.7 million from the Company's 2026 projected test year, based on his assessment that these projects are budget estimates and in the early phase of development. Mr. Coppola testified that, as shown in Exhibit A-12, Schedule B5.1, p. 3, DTE has projected capital expenditures of $241 million for 2025, and $324.1 million for the test year. In discovery, Mr. Coppola requested that DTE provide updated project phases and CODs for each project of $3.0 million or more. According to Mr. Coppola, most projects for 2025 are either completed or have firm cost estimates; however, for 2026, Mr. Coppola determined that most of the projects are based on expected bids or the Company's own budget

[248] Attorney General reply, 17.
[249] Attorney General reply, 17.

estimates.[250] Although Mr. Coppola did not take issue with any of the "bid estimate" projects, he raised concerns that the costs for projects based on DTE's internal budgeting are not sufficiently advanced to be included in rates at this time.

As shown in Exhibit AG-12, p. 1, Mr. Coppola recommends disallowance of: (1) $6.9 million for the Monroe Unit 1 SCR Catalyst Layers 1, 2, and 4; (2) $22.9 million for the CTG11 Hot Gas Path Overhaul; (3) $23.8 million for the CTG12 Hot Gas Path Overhaul; (4) $6.3 million for the BWEC Steam Turbine Valves; and (5) $3.8 million for the Renaissance Unit 3 Peaker Combustion Overhaul.

In rebuttal, Ms. Guillaumin pointed to Table 1 in her direct testimony at 3 Tr 555, and pages 2 and 3 of Exhibit AG-12, stating that "I was asked to define the current phase of development for each project over $3 million. In response, I utilized Table 1 of my revised direct testimony . . . to define each project. This is a high-level definition and does not completely specify what work has been completed."[251] Referencing Exhibit A-54, Schedule UU5, Ms. Guillaumin explained:

> The five projects Witness Coppola recommends for exclusion have full internal approval, a defined scope . . . and cost estimates based on actual costs from similar projects completed in the recent past or based on vendor proposals for the specific project. Most have contracts that were negotiated, including the Renaissance Unit 3 Combustion Overhaul, the BWEC Hot Gas Pass Overhauls on CTG11 and CTG12, and the BWEC Steam Turbine Valve Overhauls. Materials have been ordered and/or are in stock for the BWEC hot gas path overhaul and steam turbine valve projects. All five projects are progressing on schedule to meet the planned project timelines.[252]

[250] 4 Tr 3462.
[251] 3 Tr 700.
[252] 3 Tr 700.

In her brief, the Attorney General points out that Ms. Guillaumin "admits that all she provided in direct testimony *and* in response to discovery was a high level definition [that] did not cover work that has been completed."[253] According to her, this fact alone should disqualify these costs. Second, the Attorney General maintains that the costs associated with these projects are preliminary and should not be included in rates. She argues:

> [T]he Commission should hold DTE to a higher standard of support for cost recovery. In rejecting the costs, it will send the message to DTE that 1) the Company needs to more fully support cost projections in its testimony and especially when asked for further support in discovery, and 2) when DTE does come in for cost recovery, if it is reasonable, the costs will much more closely align with what is actually experienced, rather than speculative projections.[254]

In its reply brief, DTE argues that the Attorney General mischaracterizes the Company's discovery response as a confirmation that DTE "failed to provide full information," observing that the response "clearly points the AG to where DTE Electric provided detail on the current phase of development for each project."[255]

This PFD agrees with the Attorney General that DTE's discovery response, contained in Exhibit AG-12, does not provide the level of detail requested. For example, on page 2, the facility, unit, and project description are provided, as well as a "high level breakdown" of the purpose of the project (safety, reliability, environmental), and the expected in-service date. However, under "current phase of development" the projects are characterized as "bid estimate," "budget estimate" or "full detail, firm price estimate." Cross referencing that with Table 1 of Ms. Guillaumin's direct testimony (3 Tr 555)

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[253] Attorney General brief, 54.
[254] Attorney General brief, 55.
[255] DTE reply, 23-24.

indicates that a bid estimate is equivalent to a Class 3 estimate under the AACE cost estimate classifications. This is also not the information the Attorney General requested when asking for the specific phase of development.[256]

This PFD finds that the detailed information that DTE did offer for the projects at issue, namely in Exhibit A-54, Schedule UU5, was provided too late in this proceeding for the Attorney General or other parties to evaluate. As such, the costs for the five routine projects, totaling $63.7 million, should be disallowed. In the alternative, the Commission could consider a disallowance consistent with Staff adjustments for IT projects with equivalent AACE cost estimates, as discussed in more detail below.

C. MERC/Fuel Supply

Mr. Milo testified regarding DTE's MERC fuel supply capital expenditures, explaining that MERC is a wholly owned subsidiary of DTE that provides coal transportation services through a shipping terminal in Superior, Wisconsin. He specified that MERC is scheduled to shut down in June, 2026 when the Company's Belle River plant converts from coal to natural gas.[257] Mr. Milo testified that Exhibit A-12, Schedule B5.2 outlines capital expenditures for fuel supply and MERC across historical and projected periods, noting that remaining MERC assets are proposed for securitization after operations cease, as detailed in Case No. U-21534.[258]

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[256] Question No. AGDE-3.110a states: "Refer to Exhibit A-12, Schedule B5.1, pages 6 and 7. For 2025 and 2026 and for each project of $3 million or greater, please: a. Provide the current phase of project development (i.e., Preliminary Assessment, Conceptual Design, Engineering Design, Construction, Completed, etc.) and the completion and in-service month and year." Exhibit AG-12, p. 2.
[257] 3 Tr 720, 721.
[258] 3 Tr 724.

Mr. Milo explained that the capital expenditures for MERC decline from $0.87 million in 2023, to $0.31 million in 2024, to $0.11 million in 2025, with no expenditures in 2026. According to him, capital expenditures for MERC and fuel supply are related to safety, reliability, environmental requirements, and replacing end-of-life equipment. He added that the proposed expenditures are necessary and non-avoidable.[259]

DTE points out in its brief that no party took issue with capital expenditures for fuel supply and MERC. Accordingly, these amounts should be approved for recovery. Issues concerning MERC O&M expense are discussed below.

D. Nuclear Production

Company witness Davis discussed and supported investments that DTE contends are necessary to properly maintain the Fermi 2 nuclear plant, as shown in Exhibit A-12, Schedule B5.3 and Exhibit A-20, Schedule J2. For the historical year, the bridge period and for the projected test period capital investments total $264.0 million, $399.6 million and $187.4 million respectively.[260] Mr. Davis explained that the proposed investments in Fermi 2, shown in Exhibit A-12, Schedule B5.3, page 1, line 11 "accurately represent[] the capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage" adding that the proposed capital projects reflect the Company's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045."[261]

According to Mr. Coppola, DTE had actual capital expenditures for nuclear generation, excluding nuclear fuel, of $187.7 million for 2024, and has forecasted $76.3

[259] 3 Tr 725.
[260] 3 Tr 421.
[261] 3 Tr 486.

million for 2025 and $187.1 million for 2026 for both routine and non-routine projects in Exhibit A-12, Schedule B5.3.[262] He proposed several adjustments, totaling almost $80 million, which are discussed in detail below.[263]

In rebuttal, Mr. Davis opined that the proposed disallowance is imprudent and unreasonable.[264] DTE, in its brief, highlights that the total projected capital expenditures for 2023 were $266.7 million in Case No. U-21534, and that actual nuclear generation capital expenditures were $264 million, a variance of approximately 1% of the projected total nuclear generation spending.[265] In addition, the Company notes that Mr. Coppola's proposed reductions would eliminate almost "30% of the Company's projected capital expenditures for two years at Fermi 2."[266] To view expenditures correctly, Mr. Davis recommended "reviewing capital expenditures in the aggregate as that is a reasonable and prudent approach given the potential nuclear safety and reliability implications of disallowing a specific project."[267]

The Commission has consistently conducted its reviews on a project-by-project basis. Thus, unless a project is discussed below, and disallowance of specific spending is recommended, this PFD otherwise recommends adoption of the nuclear generation capital expenditures in the amounts sought. Matters not discussed below appear to be uncontested.

1. Security System Computer

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[262] 4 Tr 3464, citing Exhibit A-12, Schedule B5.3.
[263] 4 Tr 3464.
[264] 3 Tr 516.
[265] DTE brief, 89.
[266] DTE brief, 90. 3 Tr 516-517.
[267] 3 Tr 528.

As part of the routine and small projects expenditures, Mr. Davis indicated that the security system computer, plant radio system, and plant wireless projects were multi-year routine and small projects with largely online implementation, so they were not subject to the general pattern of other routine and small projects expenditures.[268] Mr. Davis outlined the security system computer project, explained why it was deemed necessary, and stated that the project was completed and put in service in February 2025.[269] The new security computer systems had to meet with Nuclear Regulatory Commission (NRC) requirements, and had to be designed and tested for continuous operations while the old system was maintained during the installation.[270] This resulted in $17 million spending for the historical test year, $16.1 million for the bridge forecast period, and $0 forecasted for spending in the test year.[271] Mr. Davis emphasized that the project was competitively sourced.[272]

Mr. Coppola testified that DTE actually spent $17,011,000 in 2023 and $13,441,000 in 2024 on the security computer system, with $2,627,000 forecasted for 2025.[273] According to Mr. Coppola, the cost of the project was contested in Case No. U-21534, and the Commission approved a total of $39.2 million for the project in that case through the projected test year. Nevertheless, Mr. Coppola noted that DTE responded in discovery in this case that the project cost has increased to $41.6 million.[274] Mr. Coppola

[268] 3 Tr 438.
[269] 3 Tr 438-442, 448.
[270] 3 Tr 441.
[271] 3 Tr 438.
[272] 3 Tr 442.
[273] 4 Tr 3464, citing Exhibit A-12, Schedule B5.3.
[274] 4 Tr 3464-3465.

recommended disallowance of $2.4 million for the 2025 bridge period to signal that DTE would be held accountable for cost overruns and failure to control costs.[275]

Mr. Davis responded by citing his testimony in Case No. U-21534, summarizing that the replacement project is an infrequent and complex undertaking that required changes in its scope, including additional site acceptance testing, additional cameras and microwave zones, updates to cyber assessments, and final system adjustments, resulting in the incremental $2.4 million cost adjustment.[276] Although factory acceptance testing and initial integrated testing were completed "without issue," the system did not respond as designed to "more complex security scenarios," and required mitigation measures.[277] Mr. Davis maintained that the projected cost had increased by approximately 6%, and that this replacement of a "significant portion of the Fermi 2 security equipment" was required to operate the NRC-regulated Fermi 2 Physical Protection Plan.[278] He repeated that the security system computer was placed in service in February 2025, with the replacement providing additional communication systems margins and addressing past NRC evaluation feedback.[279]

In her brief, the Attorney General contends that Mr. Davis's rebuttal ignores that cost overruns have extended beyond this case, quadrupling from the initial estimate of $9,948,000 to $29,225,000 in Case U-21534. What is now being requested, per the Attorney General, represents an additional cost overrun.[280] She characterizes Mr. Davis's

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[275] 4 Tr 3464-3465.
[276] 3 Tr 523, citing Exhibit AG-13.
[277] 3 Tr 523-524.
[278] 3 Tr 524.
[279] 3 Tr 525-526.
[280] Attorney General brief, 56-57.

rebuttal testimony as holding no one accountable for the higher costs, repeating her belief that customers should not carry the burden of the increasing project costs. In both her initial and reply briefs, the Attorney General again recommends disallowance of $2.4 million.[281]

DTE responds that the project cost increases were "necessary to mitigate challenges that arose in ensuring [the computer] could respond as designed," and that the replacement of the security equipment was necessary "to support the NRC-regulated Fermi 2 Physical Protection Plan."[282] DTE contends that the $2.4 million in capital expenditures that Mr. Coppola seeks to eliminate were reasonable and supported based on implementation challenges, repeating that the security system computer replacement addressed past evaluation feedback from the NRC.[283]

In its reply brief, DTE contends that the increases in costs were not, as the Attorney General asserts, cost overruns, but the natural evolution of the scope and cost of the project from its initial, partial $9.9 million request.[284] DTE continues to stress that the project was part of "a critical, NRC-regulated security upgrade," adding that unforeseen issues arose during the project that "required scope adjustments."[285] Otherwise relying on its earlier arguments and testimony to assert that the expense is fully supported, DTE further contends that the mere fact that costs exceed projections is not sufficient evidence of unreasonableness or imprudence, and the Attorney General's recommended

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[281] Attorney General brief, 57. Attorney General reply, 31-32.
[282] DTE brief, 91.
[283] DTE brief, 91, citing Mr. Davis's testimony, 3 Tr 524.
[284] DTE reply, 66-67.
[285] DTE reply, 67.

disallowance of $2.4 million is unfounded.[286] Contrary to the Attorney General's assertion, there is no message that needs to be sent through disallowance.[287]

The Commission addressed similar arguments in Case No. U-21534 when the total project cost was projected at $39 million, crediting the Company's explanation regarding "nine security-related items with changed costs," and also crediting DTE's position that the project was competitively sourced.[288] While it is true that DTE's explanation of additional site acceptance testing, more new cameras and microwave zones, added cyber assessments, and final system adjustments is not as clear as the nine changes outlined in Case No. U-21534, no one disputes that the computer is now in service. The additional $2.4 million expenditure does not appear to be unreasonable to complete the project and final installation. Accordingly, this PFD recommends that the Attorney General's adjustment be rejected.

2. Plant Radio System

Mr. Davis stated that the plant radio system replacement project capital expenditures were $6.0 million for the historical year, with $5.1 million projected for the bridge period, and nothing for the projected test year.[289] He outlined many of the issues leading to the radio replacement, including, but not limited to, inaudibility of field radio communications in the Fermi 2 main control room (MCR), and adding VHS and 800 MHZ radio frequencies to the existing UHS frequency band that had been available from the antenna system installed in the 1980s. The project allowed for improved operations

[286] DTE reply 67-68.
[287] DTE reply, 67-68.
[288] January 23, 2025 order in Case No. U-21534, pp. 59-62.
[289] 3 Tr 442, citing Exhibit A-12, Schedule B5.3, page 2, line 3.

communications in all areas of the plant, as well as with emergency responders, and required installation of 16 new antennae and approximately 5,800 feet of new conduit and cable. Mr. Davis added that the old plant radio system had to be maintained while the new one was installed, the replacement had to allow other Fermi 2 plant systems to remain functional, it had to meet NRC and FEMA requirements, and it had to be designed and tested for continuous operations with little maintenance time.[290] The replacement project was completed and placed in service in February 2025.[291]

Mr. Coppola recommended disallowance of $1.3 million in relation to the plant radio system replacement project.[292] The project had actual capital expenditures of $6,049,000 for 2023 and $3,807,000 for 2024, with forecasted capital expenditures of $1,311,000 for 2025 and no expenditures in 2026.[293] When the project was contested in Case No. U-21534, it was projected to have $19.4 million in costs through 2025.[294] Discovery in this case revealed that the total project cost is now estimated at $20.7 million; Mr. Coppola recommended disallowance of the difference between $20.7 million and $19.4 million.[295]

Mr. Davis clarified that the $1.3 million adjustment was to address unanticipated radio signal dead spots that were unique to the complex and exact equipment

[290] 3 Tr 443-445.
[291] 3 Tr 442.
[292] 4 Tr 3465-3466.
[293] 4 Tr 3465.
[294] 4 Tr 3465-3466.
[295] 4 Tr 3466.

locations.[296] All of the components had passed factory acceptance testing. Mr. Davis repeated that the radio system was placed in service in February 2025.[297]

The Attorney General counters that the cost overruns have continued through multiple cases, with the project cost more than tripling from the original $6.0 million estimate to $19,430,000 in Case No. U-21534.[298] She views approval of the additional costs as writing a "blank check" to DTE for these projects where no one is held accountable for those increased costs. As a result, the Attorney General repeats her recommendation that $1.3 million be removed from DTE's 2025 capital expenditures.[299] This recommendation and its underpinnings are again repeated in the Attorney General's reply brief, with the Attorney General expressing the corollary concern that DTE did not hold any vendor or contractor accountable for the repeated cost overruns.[300]

DTE responds that the radio signal dead spots that had to be addressed were both unanticipated and unacceptable for the plant system. The Company again contends that completion of the plant radio system "provides Nuclear Security with additional communication systems margins."[301] Similarly, DTE's reply brief relies on earlier arguments and testimony, but it also quotes the Company's discovery responses to the Attorney General to support that the additional costs were due to necessary and unforeseen circumstances that only arose after the radio system was fully integrated with parts of different manufacturers. DTE repeats that the additional costs for which the

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[296] 3 Tr 524-525.
[297] 3 Tr 525.
[298] Attorney General brief, 58.
[299] Attorney General brief, 58-59.
[300] Attorney General reply, 32-33.
[301] DTE brief, 91.

Company now seeks approval were not cost overruns. Instead, the initial budget approvals were partial, at best, and did not include all costs or the necessary evolution of the project over time.[302]

Again, the Commission addressed similar arguments in Case No. U-21534 when the total project cost was forecasted to be $19.43 million.[303] And, once again, the Commission rejected the Attorney General's proposed disallowance in that case.[304] This PFD sees no reason to deviate from past Commission action and recommends approval of the final plant radio system project costs, as requested, particularly where the radio is now in service and the relatively modest increase was used to bring this project to fruition.

3. Routine Nuclear Projects

Mr. Davis outlined routine and small projects capital expenditures for Fermi 2, generally, characterizing the expenditures as those required for safe operation, like pump, motor, valve, and reactor control component replacements, and as part of a proactive maintenance and replacement strategy.[305] Exhibit A-12, Schedule B5.3, shows routine and small projects totaling $64,822,000 in the historical year; $90,818,000 for 2024; $29,249,000 for 2025; and $72,656,000 for 2026. Mr. Davis added that the expenditures and projects are "generally consistent each operating cycle and peak during refueling outage periods."[306] The 2025 bridge year precedes a refueling outage in spring 2026, so

[302] DTE reply, 68-69.
[303] January 23, 2025 order in Case No. U-21534, pp. 59-62.
[304] January 23, 2025 order in Case No. U-21534, pp. 61-62.
[305] 3 Tr 435-452, citing Exhibit A-12, Schedule B5.3, pp. 2-3.
[306] 3 Tr 436.

2025 spending reflects planning, readying, and material procurement, and 2026 includes several projects to be completed and put into service.[307]

In addition to taking issue with the routine nuclear capital projects of the security system computer replacement, the plant radio system replacement, discussed separately, Mr. Coppola took issue with three routine nuclear capital projects (document management system enhancements, reactor recirculation system (RSS) replacements, and natural draft cooling towers), opining that the projects are still in a very early stage of development and premature to include in rate base at this time.[308] Mr. Coppola explained that he requested additional information by project, including current phase of development, and next phases with timelines, as well as related dollars to be spent in each phase, for projects costing $3.0 million or more.[309]

In response, the Company indicated that it does not use project management phases, or track costs by project phase, but provided some information regarding completed projects, project progress, and projects not yet commenced.[310] Mr. Coppola recommended removal of $24,331,000 from 2026 capital expenditures for the three projects that have not yet commenced.[311]

In relation to the document management system enhancements project, expected to go into service in 2028, and the RRS, expected to go into service in 2027, Mr. Davis pointed to Ms. Uzenski's testimony that the projects would have no impact on revenue

[307] 3 Tr 437.
[308] 4 Tr 3468.
[309] 4 Tr 3467.
[310] 4 Tr 3467-3468.
[311] 4 Tr 3468, citing Exhibit A-12, Schedule B5.3, p. 3, lines 52, 59, and 61.

requirement and deficiency because they would not be in service during the test period.[312] Mr. Davis stated that multi-year projects were appropriately included in the current rate case to start the projects and to provide proper accounting and ratemaking treatment. Although the projects might "not directly impact revenue requirements in this case, they represent necessary, well-justified expenditures" meriting Commission affirmation of "appropriateness for accounting and ratemaking purposes."[313] He again stressed the necessity of the investments for "safe and reliable Fermi 2 operations over the long term."[314]

In relation to the natural draft cooling tower project, Mr. Davis noted that work scope had been completed in 2024, and that the work scope had been approved for 2025 through 2028. Materials and services had been sourced, and the projected in-service date is June 2026.[315] The Company classifies the work as "not started" because the work is "not scheduled to restart implementation with the replacement of 22 bays of fill until 2026."[316]

Mr. Davis outlined the layout of the two towers, and testified that the natural draft cooling tower work cannot be done during the summer because the project requires removal of portions of the cooling towers, lessening their cooling capacity, which starts a cascade of potential impacts that could include plant derate or full shutdown.[317] The project is considered reoccurring, and not a continuous project because it is necessarily

[312] 3 Tr 519.
[313] 3 Tr 519-520.
[314] 3 Tr 520.
[315] 3 Tr 521.
[316] 3 Tr 521.
[317] 3 Tr 522-523.

seasonal. It is also because the project plan is modular and the planning and execution of the fill replacement scope is "proceduralized," so there are only a few months from the start of implementation planning through material ordering and replacement activities.[318] For instance, similar work was started in February 2019 and completed in May 2019.[319]

In his rebuttal testimony, Mr. Davis again focused on the document management system enhancements and RRS having no impact on DTE's revenue requirement and deficiency, and that commencement expenditures are properly included for accounting and approval in this case.[320] Mr. Davis went into more detail in relation to natural draft cooling towers, citing Exhibit A-20, Schedule J2, page 25, and noting that the projected work scope to replace 22 bays of fill is scheduled to occur in 2026.[321] He again explained the nature of the project and why it is considered a reoccurring, and not a continuous, project.[322] He also explained that the sourcing of services and materials is complete for the projected in-service date of June 2026 for the work scope scheduled for the 2025 to 2026 work cycle and routine outage.[323]

The Attorney General discounts Mr. Davis's repeated use of the words "safe" and "safety" without greater detail, even when the proposed expenditures "may be well outside of the test period." She contends that this unreasonably inflates costs with "mostly hypothetical and speculative projections." The Attorney General maintains her recommendation that $24,331,000 be removed from capital expenditures.[324]

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[318] 3 Tr 522.
[319] 3 Tr 523.
[320] 3 Tr 518-521.
[321] 3 Tr 520-521.
[322] 3 Tr 521-523.
[323] 3 Tr 521.
[324] Attorney General brief, 63.

DTE, in turn, contends that the Attorney General is not appropriately recognizing that the Company has completed sourcing services and materials, and has a projected June 2026 in-service date, for the natural draft cooling tower project. The Company reiterates its position that projects not projected to go into service during the test period have no impact on the revenue requirement and deficiency, but they are still appropriately included as necessary and justified expenditures to obtain a "Commission determination affirming their appropriateness for accounting and ratemaking purposes."[325] DTE's reply brief attempts to undermine the Attorney General's position, but otherwise offers no new insights in relation to routine nuclear capital projects, apart from again noting the progress of the natural draft cooling tower project.[326]

DTE has sufficiently explained the need for the cooling tower project, as well as the timing. Thus, this PFD finds that the projected costs will be incurred in 2026, and those expenditures should be included and approved in this rate case. The same cannot be said for the RRS and the document management system enhancement project. The RRS has a projected test year expenditure of $5,125,000.[327] The document management system enhancements project has projected spending of $408,000 for 2025, and $9,159,000 for 2026.[328] This PFD recommends the combined disallowance of $14,682,000 for these projects for the reason that, given the early stages of development, DTE has not established when the expenditures will actually be incurred. As noted by DTE, removal of these expenditures will have no impact on the revenue requirement.

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[325] DTE brief, 90.
[326] DTE reply, 72-73.
[327] Exhibit A-12, Schedule. B5.3, p. 3.
[328] Exhibit A-12, Schedule B5.3, p. 6.

4. Non-routine Nuclear Projects

According to Mr. Coppola, the Attorney General requested that DTE provide additional information for projects of at least $3.0 million falling under the umbrella of the 26 non-routine projects with total forecasted capital expenditures of $49.1 million for 2025 and $114.5 million for 2026.[329] DTE responded that nuclear generation operation does not use project management phases, does not track costs by project phase, "and does not otherwise conform to generally accepted project management protocols."[330] Nevertheless, DTE provided some basic information about whether projects were completed or in progress. Based on this information, Mr. Coppola stated that three projects (turbine controls replacements, reactor recirculation motor-generator (RRMG) replacements, and circulating water (CW) traveling screens) with total forecasted expenditures of $8,742,000 for 2025 and $28,298,000 for 2026, were not yet started.[331] Mr. Coppola recommended removal of $8,742,000 for 2025 and $28,298,000 for 2026 for those projects, contending that their inclusion in rate base in this case is premature.[332]

In his direct testimony, Mr. Davis spoke generally regarding the non-routine and large projects set forth in Exhibit A-12, Schedule B5.3, page 4, noting $89.2 million projected for 2024, $145.1 million for 2025, and $114.5 million for 2026.[333] He then outlined the expenditures of the individual projects and their underlying rationales.[334]

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[329] 4 Tr 3468.
[330] 4 Tr 3468-3469.
[331] 4 Tr 3469, citing Exhibit A-12, Schedule B5.3, page 4, lines 15, 22, and 25.
[332] 4 Tr 3469.
[333] 3 Tr 453.
[334] 3 Tr 454-459, 461-471, 473-480.

In relation to the turbine controls replacements questioned by Mr. Coppola, Mr. Davis testified that these "regulate turbine speed and protect the Fermi 2 turbine set and main generator unit," and that the project to replace the main unit turbine controls results from their being at the end of life and obsolete.[335] The expenditures are projected to be $2.2 million in the bridge period and $4.4 million in the test year.[336] Mr. Davis added that, while the turbine controls do not have a nuclear safety function, their installation will improve margins against main turbine and main unit generator damage.[337] The project is expected to be completed in the spring of 2030 and go into service later that year.[338]

Mr. Davis testified that the RRMG replacement project questioned by Mr. Coppola is projected to be completed and placed in service in spring of 2028, with projected bridge period spending of $7.2 million and test period spending of $17.8 million.[339] The RRMG sets are part of the Fermi 2 Reactor Recirculation System (RRS) providing variable power to the RRS pump motors, "one RRMG set controls," and one RRS pump motor.[340] The RRMG motor rotors have been in service since the 1980s, and replacement will reduce shorts, decrease house electrical loads, and serve the nuclear safety function of the RRS providing "sufficient flow to ensure adequate heat removal from the core."[341]

For the third project that Mr. Coppola opined was premature to include in this rate case, Mr. Davis testified that the CW traveling screens project would replace stationary debris screens at the circulating water pump house (CWPH) intake structure with traveling

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[335] 3 Tr 471-472.
[336] 3 Tr 471.
[337] 3 Tr 472.
[338] 3 Tr 471.
[339] 3 Tr 474.
[340] 3 Tr 474-475.
[341] 3 Tr 474-475.

screens, with the project to be completed and in service in 2027. The capital expenditures are forecasted to be $0.1 million in the bridge period and $6.2 million in the test year.[342] Mr. Davis explained that the CW system transports rejected cycle heat from the main unit condenser to the two parallel natural draft cooling towers, and that the CW screens filter debris at the CWPH intake as CW cycles from the cooling towers towards the main unit condenser.[343] The CW does not have a nuclear safety function, but the reliability of the feed water system is a function of electrical grid system operating requirements. Mr. Davis further indicated that replacement of the CW stationary screens with traveling screens will "improve the margin of the CWPH intake filtering and will incrementally improve the reliability of the main unit condenser."[344]

In relation to these non-routine nuclear capital projects, the Attorney General maintains in her brief that the projects are in a very early stage of development for this rate case and are premature. She repeats that the more than $37 million proposed in this case is for projects not yet started, and that the projections are too speculative and undeveloped for the costs to be passed on to customers. As a result, the Attorney General again recommends removal of $8,742,000 for 2025 and $28,298,000 for 2026.[345]

In his rebuttal testimony, Mr. Davis responded by asserting that his direct testimony supported the project expenditures, and he referred to Ms. Uzenski's testimony confirming that projects that do not go into service during the projected test period do not alter DTE's revenue requirement and deficiency.[346] He further stated that Mr. Coppola

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[342] 3 Tr 477.
[343] 3 Tr 477-478.
[344] 3 Tr 478.
[345] Attorney General brief, 64-65.
[346] 3 Tr 518-519.

was “making only an accounting argument . . . for excluding these projects.”[347] And he added that the in-service projections of 2030 for the turbine controls replacements, 2028 for the RRMG, and 2027 for the CW traveling screens were only provided for clarity regarding potential effect on the revenue requirement.[348] Mr. Davis testified generally regarding the necessity for all of the proposed projects to operate Fermi 2 safely and reliably.[349] DTE’s initial and reply briefs repeat the same points regarding all nuclear generation capital expenditures, stressing nuclear security and safety for Fermi 2-related projects.[350]

This PFD harbors little doubt of the value of the projects in relation to nuclear security and safety. This PFD does doubt, however, when the project spending will actually occur in the bridge or test period. Given that the earliest of the three contested projects is not slated to go into service until 2027, this PFD agrees with the Attorney General that $8,742,000 for 2025, and $28,298,000 for 2026, should be disallowed as premature. For equipment purchasing costs in advance of projects being put into service, more information regarding when essential components will be purchased, and costs of these components may be requested in a future rate case when plans are more certain. As DTE notes, removal of these costs does not affect the Company’s revenue requirement.

5. Underground Water Piping Replacement

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[347] 3 Tr 518.
[348] 3 Tr 519.
[349] 3 Tr 517, 528.
[350] DTE brief, 89-92. DTE reply, 73.

Mr. Davis outlined the underground safety-related service water piping project, specifically the Emergency Equipment Service Water (EESW) and Residual Heat Removal System Water (RHRSW) systems, and he outlined the underlying purpose of the piping itself.[351] He stated that the replacement was completed in spring 2024 and put into service; as a result, it has historical test year spending of $10.5 million, and projected bridge period expense of $18.8 million, with nothing projected for the test year.[352]

Mr. Coppola raised the issue that the underground water piping project was initially estimated to cost $44.3 million, and it had a final cost of $91.3 million.[353] He testified that DTE's explanation for the increase was that the project was re-evaluated in spring of 2022 after Refueling Outage 21, and the cost estimate increased to $103 million. He further stated that the appropriation request provided by DTE through discovery "identified $12.6 million to moving the project from 'MEP to Fermi Capital.'"[354] Because this entry was unexplained, unjustified, and related to a huge project cost increase, Mr. Coppola recommended removal of the $12.6 million from the 2024 actual capital expenditures.[355]

According to Mr. Davis, the phrase quoted by Mr. Coppola is shorthand for "Outage Shared Cost 12.6M – Due to moving from MEP to Fermi Capital."[356] He explained that the MEP to Fermi Capital notation properly allots shared services, materials and personnel during an outage from Major Enterprise Projects, which does not generally include shared activities in its original budgeting appropriation requests, to Nuclear

[351] 3 Tr 459-461, citing Exhibit A-12, Schedule B5.3, p. 4, line 4.
[352] 3 Tr 459.
[353] 4 Tr 3466, citing Exhibit A-12, Schedule B5.3, p. 4, line 4, and Exhibit AG-14 CONF.
[354] 4 Tr 3467.
[355] 4 Tr 3467.
[356] 3 Tr 527.

Generation where the "shared capital expenditures were always going to be incurred."[357] Mr. Davis stated that the project initially, and inappropriately, budgeted for the shared costs to "be absorbed by other capital projects;" based on work in spring 2022 and 2024.[358] The notation of the internal move was simply to properly apportion the expense.[359]

Mr. Davis also stated that, as reflected in his testimony in Case No. U-21534, relying on internal DTE "authorization forms can lead to misunderstandings and misconceptions regarding actual project performance."[360] He added that $103 million in expenditures had been approved for the project, with $3.8 for an unused contingency, $12.6 million for outage shared cost, $5.8 million for Nuclear A&G, and $2.6 million for "Corporate OH."[361] Mr. Davis added that the "MEP to Fermi Capital" was solely a shorthand phrase used in internal deliberation, and it did not result in a change in the actual nuclear generation total capital expenditures, "but simply noted where certain shared capital expenditures should be reflected at the project-level."[362] Finally, he indicated that "the $12.6 million of expenditure did not arise as of a consequence of, and was not influenced by, the internal DTE organization here it was allocated or the execution of the project," adding that the "expenditure was not additional or incremental."[363]

The Attorney General characterizes Mr. Davis's rebuttal as confusing and unresponsive. She questions why DTE believes the burden should be on intervenors and

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[357] 3 Tr 526-527.
[358] 3 Tr 527.
[359] 3 Tr 527.
[360] 3 Tr 526.
[361] 3 Tr 526.
[362] 3 Tr 526-527.
[363] 3 Tr 527-528.

the Commission to identify and understand DTE's internal budgeting proposals; the burden is on DTE to support its expenditures beyond asserting that spending should be viewed in the aggregate and making allusions to safety and reliability concerns.[364] And she finds it "both concerning and perplexing" that DTE indicates that its own documents should not be relied upon without additional explanation, and where no clear explanations and context have been forthcoming.[365] Because the explanations provided have been inadequate and fail to provide a justification for the requested $12.6 million cost, the Attorney General recommends that the $12.6 million be removed from 2024 actual capital expenditures for the piping replacement project.[366] DTE, for its part, reiterates that this was misunderstood to be an incremental expenditure when it was actually a notation that a shared capital expense would be attributed to this specific Company organization.[367]

The Attorney General replies that it is up to DTE to fully support its cost requests, and that she and Mr. Coppola "went out of their way to follow up on this request and attempt to understand DTE's filing and rebuttal."[368] She rejects DTE's claims that documentation provided by the Company in discovery should not be relied upon without additional Company clarification. As a result, the Attorney General concludes that the $12.6 million for the piping project has not been supported and should be removed from 2024 capital expenditures.[369]

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[364] Attorney General brief, 60-61.
[365] Attorney General brief, 61-62.
[366] Attorney General brief, 62.
[367] DTE brief, 91-92.
[368] Attorney General reply, 33-34.
[369] Attorney General reply, 33-34.

DTE replies, in turn, that the $12.6 million is not an additional expense, it is not an incremental spending change, and it is not a change to the total project cost, but only a notation regarding where the shared capital cost should be recorded.[370] Instead, DTE urges that "[d]isallowing this amount would misstate the project's accounting rather than protect customers."[371] DTE relies upon its earlier explanations of the expense, as well as Mr. Davis' testimony and the discovery responses found in Exhibit AG-84, both quoted in DTE's reply brief, to again contend that the Commission should reject the Attorney General's proposed disallowance.[372]

Interestingly, in Case No. U-21534, the RHRSW had only $974,000 spend in Exhibit A-12, Sched. B5.3, page 2, line 27, for the 2022 historical year.[373] The source of the $12.6 million being transferred, and for which approval is requested in this case, is elusive. As is the $3.8 million unused contingency referred to by Mr. Davis.[374] Because the source of the $12.6 million to be transferred to non-routine nuclear capital projects in this case is still unclear, beyond coming from somewhere in Major Enterprise Projects, this PFD recommends its disallowance. It is assumed that the $3.8 million for contingency identified by Mr. Davis is applicable to another category of expenditures and was removed.

E. Distribution

1. Background

[370] DTE reply, 70.
[371] DTE reply, 70.
[372] DTE reply, 70-72.
[373] The EESW only had $1,669,000 for historical year 2022, as well. Case No. U-21534, Exhibit A-12, Schedule B5.3, p. 2.
[374] Mr. Davis's rebuttal testimony, 3 Tr 526.

Mr. Chiu provided a detailed review of DTE's distribution operations, which includes both base capital programs as well as strategic capital investment programs.[375] Base capital represents expenditures that are not discretionary and are not under the Company's control such as storm restoration, relocations, and new customer connections. Strategic capital investments are for the most part discretionary and, according to Mr. Chiu, are aimed at repairing, replacing, and modernizing DTE's distribution system.[376]

According to Mr. Chiu, and as set forth in Exhibit A-12, Schedule B5.4, p.1, DTE invested $1.6 billion in the 2023 historical year and is requesting $3.2 billion of capital investment for the two-year bridge period, and $1.9 billion of capital investment for the test year for distribution operations. Staff and intervenors raised issues in both the base capital and strategic capital investment programs. These disputes are addressed in detail below, after first addressing appropriate inflation rates and constant dollar averaging (CDA) of past base capital expenditures.

2. Inflation

In the January 25, 2025 order in Case No. U-21534, pp. 68-75 and 211-214, the Commission discussed various proposed inflation rates to be applied to the bridge and 2025 test periods. While rejecting DTE's CDA approach for Emergent Replacements, as discussed below, the Commission ultimately approved the Company's blended inflation rates, stating that its approval was consistent with prior orders and:

> DTE Electric provided evidence that the composite inflation rate "separates labor inflation, which is subject to Company-specific dynamics like collective

[375] 3 Tr 1088-1091.
[376] 3 Tr 1089.

> bargaining agreements, from non-labor inflation. . . . DTE Electric's witness also noted that the company and the Attorney General used the same CPI-Urban (CPI-U) rate for non-labor costs, with the only difference being the source document. On this record, the Commission approves the use of the blended rate, and directs DTE Electric, in its next rate case, to provide further detail on the company-specific dynamics that justify rejection of the CPI-U or a similar widely-used rate for labor costs.[377]

In addition to adopting the Company's blended inflation rate, and rejecting Staff's and the Attorney General's recommended use of the Consumer Price Index All Urban (CPI-U), without any company-specific adjustment for labor inflation, the Commission also rejected ABATE's proposal to apply the Real GDP Chained Price Index, finding "the CPI is the most widely used measure of inflation, and the Commission finds that ABATE failed to show how the Real GDP Chained Price Index is superior to the CPI-Urban for either labor or non-labor costs or why the Real GDP Chained Price Index's customer substitution treatment is superior to the periodic updates made in the CPI's basket of goods."[378] In addition, the Commission rejected, without discussion, the proposal by MNSC to offset inflation by applying a labor productivity factor.[379]

In this case, Ms. Uzenski, and Mr. Fix for DTE, Staff witnesses Ufolla and Ruekert, Mr. Coppola, Ms. York, and NRDC/CUB witness Bunch presented various proposals for forecasting inflation to be applied to certain distribution investments and O&M expenses.

Ms. Uzenski testified regarding DTE's proposed inflation rates of 3.40%, 3.0%, and 3.10% for 2024, 2025, and 2026 respectively, explaining that these rates include labor inflation rates of 3.5% for 2024 and 3.0% for 2025 and 2026.[380] Mr. Fix discussed the

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[377] Order, pp. 74-75.
[378] Order, 76.
[379] Order, 214.
[380] 4 Tr 2424; Exhibit A-13, Schedule C5.15, line 15.

development of DTE's proposed labor inflation rates, noting that the Company is obligated to increase pay rates by at least 3% annually under current collective bargaining agreements. In addition, non-represented employees receive annual increases of 3%, consistent with the Company's pay practices since 2010.[381]

Mr. Rueckert and Mr. Coppola calculated inflation rates of 2.73% and 2.80% for 2025, and 2.66% and 2.40% for 2026, with no additional adjustment for labor inflation.[382] Mr. Rueckert testified that in the past, the Commission has rejected the use of a blended inflation rate, citing Case No. U-20162, further noting that DTE has some control over the labor component of inflation.[383] Mr. Coppola testified that the CPI-U from S&P Global Market Intelligence, which he used to project inflation, is more up-to-date than the Company's source and "include[s] wage increases paid by merchants and companies," noting, "[t]o add more wage adjustments would be duplicative."[384]

First, Ms. York observed that O&M numbers for 2024 are now known, and while DTE initially projected a $30.2 million increase in O&M expense over 2023, DTE's forecast was overstated by $42.8 million.[385] Referencing Table JAY-1 at 4 Tr 3241, Ms. York pointed out that from 2017 through 2024:

> The actual annual O&M expense decreased by an average rate of 0.1% per year from 2017 to 2024, while the adjusted O&M expense decreased by an average rate of 0.9% per year. Importantly, both sets of data (actual and adjusted) show that despite inflationary pressures in 2022, DTE's actual

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[381] 3 Tr 1472.
[382] See, 5 Tr 4954 and 4 Tr 3427. The difference in the proposed inflation rates is a result of different sources used by Staff and the Attorney General. Mr. Ufolla used an average of projections from IHS Global Insight, the Federal Reserve, and the Congressional Budget Office, whereas Mr. Coppola used the CPI-U from S&P Global.
[383] 5 Tr 5193.
[384] 4 Tr 3427.
[385] 4 Tr 3239-3240.

> O&M expense decreased by 2.1% relative to 2021 and its adjusted O&M expense decreased by 4.9%.[386]

In addition, Ms. York presented Table JAY-2 at 4 Tr 3246, which shows projected versus actual O&M expense by category from Case Nos. U-20561, U-20836, and U-21297. According to Ms. York, "[a]s shown in the table, DTE's total actual O&M expense for the projected test years . . . has been about 6% to 11% less than the amount requested."[387] Ms. York further observed, that despite significant inflation in 2022, "DTE's actual O&M expense decreased by 2.1% relative to 2021 and its adjusted O&M expense decreased by 4.9%."[388] Ms. York concluded that based on DTE's historical performance, the Company has demonstrated that its overall O&M costs change at a rate less than inflation.

Rather than DTE's composite labor/non-labor inflation rates, Ms. York again recommended the use of the Real GPD Chained Price Index rate of 1.4% for both 2025 and 2026 in developing an inflation projection for DTE. Ms. York explained that "there are many moving pieces with respect to the Company's labor expense," citing employee retirements and replacements by new, lower-wage employees, as factors that DTE fails to take into account.[389] She further opined that it is important to use inflation forecasts from independent economists because they have no interest in the outcome of this rate case.[390]

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[386] 4 Tr 3241.
[387] 4 Tr 3245.
[388] 4 Tr 3241.
[389] 4 Tr 3244.
[390] Id.

In summary, Ms. York recommended that no inflation be applied for 2024, and that the Real GDP Chained Price Index be used to develop test year labor and non-labor O&M expense. According to her, the GDP index is more responsive to customer substitution of goods and services, but she observed that the GDP index "does not cure the deficiency for changes in the tenure of employees but relies on independent factors to project escalations in labor costs, while recognizing DTE's history of projected O&M expenses exceeding actuals."[391]

Mr. Bunch explained that the inflation numbers that DTE used in developing its rate case are outdated and have decreased by 0.5% for 2024, 0.2% for 2025, and 1.0% for 2026, according to the same source that DTE used for its non-labor portion of overall inflation. Mr. Bunch therefore recommended that DTE's non-labor inflation be updated accordingly.[392] This would reduce the non-labor part of the Company's inflation rates to 2.9% in 2024, 2.7% in 2025 and 2.4% in 2026.[393]

Turning to labor inflation, Mr. Bunch recommended that the rates be reduced by a productivity factor, observing that DTE's actual labor compensation from 2019-2024 shows an annualized increase of only 0.23%, due to turnover, significant workforce reductions, labor productivity, divergence in labor costs between represented and non-represented employees, and other dynamics.[394] Consistent with his testimony, Mr. Bunch recommended that an offset of 1.96% be applied to DTE's labor inflation rates, based on the Bureau of Labor Statistics (BLS) Labor Productivity Index for Michigan, private, non-

[391] 4 Tr 3247.
[392] 5 Tr 4839.
[393] MNSC brief, 141.
[394] 5 Tr 4840-4841; Exhibits CUB-36, 40, and 42.

farm workers. As a result, Mr. Bunch calculated composite inflation factors of 0.60% for 2024, 1.30% for 2025, and 1.20% for 2026.[395]

Mr. Bruzzano countered that the Company's proposed composite inflation rate is consistent with the Commission's order in Case No. U-21534, and that the rates DTE proposes best reflects the inflationary pressures faced by the Company, such as collective bargaining agreements. According to him, neither Ms. York nor Mr. Coppola provide evidence that DTE's proposal is inappropriate or that the Commission erred in approving a blended inflation rate.[396] He added that Ms. York does not provide compelling evidence that the Real GDP Chained Price Index is reasonable for utility-specific costs, and Mr. Coppola provided no additional support for the use of the CPI-U beyond what the Attorney General has provided in previous cases.[397]

Similarly, responding to Staff's recommended inflation rates, Mr. Bruzzano testified that Mr. Ufolla provided no support for why the rates he proposes are appropriate, and while acknowledging that the Commission has rejected composite inflation rates in the past, the most recent DTE rate order approved the Company's proposed rates based on both labor and materials. He reiterated Mr. Fix's direct testimony regarding the Company's obligation to increase pay by 3%, per existing collective bargaining agreements, which also provide for additional increases for employees who have not reached the maximum pay rate. [398]

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[395] 5 Tr 4842-4843; MNSC brief, 142.
[396] 3 Tr 993.
[397] 3 Tr 993-994.
[398] 3 Tr 995-996.

Mr. Bruzzano addressed Mr. Bunch's recommendation regarding the application of a labor productivity factor testifying that: (1) Mr. Bunch used historical labor productivity offsets and applies them to future productivity offsets without support; (2) the years that Mr. Bunch used in developing his forecast of productivity gains "include among the most atypical economic conditions in a generation considering the overlap with a global pandemic[;]" and (3) Mr. Bunch's analysis does not explain why the particular category of Michigan private, non-farm workers is applicable to the utility industry, positing that "dissimilar industries such as retail are responsible for the change in labor productivity in greater proportion than regulated energy companies."[399]

In his rebuttal, Mr. Fix responded to Mr. Bunch's recommendation regarding labor productivity. He described Mr. Bunch's calculation of the 0.23% compound average growth rate (CAGR) for total compensation as "extremely flawed" noting that the amounts used by Mr. Bunch include total wages, including incentive compensation and benefits.[400] Mr. Fix stated that incentive compensation and benefits are variable year-over-year "and are not predictive of future costs."[401] According to him:

> Witness Bunch ignores that the Company's Total Compensation in 2024 was impacted by the Company's VSIP that resulted in a significant reduction in labor costs. Had Witness Bunch measured the compound annual growth rate on a per employee basis rather than total cost, the actual increase in labor costs per employee for the years 2019 through 2024 would be 2.79%, as reflected on Exhibit A-55, Schedule VV2, line 8, column (j), rather than his calculated 0.23%. And, when calculated exclusive of incentive compensation and employee benefits, the compound annual growth rate would be 3.27%, as reflected on Exhibit A-55, Schedule VV2, line 27, column (j). This demonstrates the reasonableness of the Company's 2024 3.50% wage escalation rate projection.[402]

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[399] 3 Tr 998.
[400] 3 Tr 1519-1520.
[401] 3 Tr 1520.
[402] Id.

DTE's brief relies on the testimony and rebuttal of Ms. Uzenski, Mr. Fix, and Mr. Bruzzano, reiterating that its proposed composite inflation rates reflect "the Company's actual labor costs and relies on a sound, reasonable resource for its non-labor costs."[403]

Staff's brief points out that the blended inflation rate proposed by DTE does not incorporate any productivity gains that accompany experience.[404] The Attorney General maintains that DTE admits that the CPI-U inflation rate includes a labor component, but it points to a study stating that wage increases do not significantly contribute to inflation.[405] According to her, however, the study relates to PCE inflation rates that are generally lower than the CPI inflation rates.[406]

ABATE relies on Ms. York's testimony, emphasizing that DTE has a track record of containing O&M costs as set forth in Tables JAY-1 and JAY-2 of Ms. York's testimony, which demonstrate that DTE's actual O&M costs have ranged from 6% to 11% less than requested and 4% to 9% less than the Commission has approved.[407] Concerning 2024 costs specifically, ABATE points out:

> In this case the Company projected an inflation adjustment for calendar year 2024 of $30.2 million, or a 2.6% increase relative to the actual O&M expense incurred in 2022 [sic]. (Exhibit A-13, Schedule C5.) The Company based this increase on a composite inflation factor reflecting a 2.9% increase based on the CPI, and a 3.5% wage escalation factor. (Exhibit A-13, Schedule C5.15.) Combining DTE's projected adjustment of $30.228 million with its actual historical 2023 O&M expense yields projected O&M expense of $1.203 billion for calendar year 2024. The Company's actual O&M expense for calendar year 2024, however, was $1.161 billion. (Exhibit

[403] DTE brief, 28.
[404] Staff brief, 170, citing 3 Tr 995.
[405] Attorney General brief, 16.
[406] Attorney General brief, 16-17; Exhibit AG-64.
[407] ABATE brief, 52-54.

> AB-7.) Thus, DTE's projected 2024 O&M expense exceeds its actual O&M expense by $42.781 million.[408]

In its brief, MNSC responds to the Company's rebuttal, arguing that using historical labor productivity is appropriate for forecasting future productivity offsets, noting:

> That the future is not the same as the past is acknowledged; but that does not mean historic annual labor cost growth is irrelevant to projected labor cost growth. To the contrary, when asked the rationale behind the Company's 3.5% average increase in annual pay for 2024, the Company cited *historic* annual percent changes in wages as its rationale for projected *future* costs.[409]

Next, MNSC contends that Mr. Bruzzano's dismissal of the BLS source Mr. Bunch used for determining productivity offsets is based on speculation about applicability of the source, pointing out that DTE could have produced an alternative reference, but failed to do so. MNSC adds that "[t]here is nothing inherently unreliable nor unreasonable in relying on the index of Michigan private non-farm workers, nor has the Company identified anything in particular indicating this index is inapplicable here."[410]

Lastly, MNSC responds to Mr. Fix's rebuttal explaining that in a discovery response, Ms. Uzenski stated that "'Labor expense is not independently projected based on headcount. Rather, O&M labor is based on the adjusted historical period expense, plus inflation and known and measurable changes,'" a statement that is inconsistent with Mr. Fix's rebuttal.[411] Moreover, MNSC contends that with a reduced workforce, a 12% reduction between 2019 and 2024, while maintaining output, DTE has obtained productivity benefits "in an inflationary wage environment" that is not captured in DTE's

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[408] ABATE brief, 49.
[409] MNSC brief, 143, citing CUB-39, p. 1.
[410] MNSC brief, 143.
[411] MNSC brief, 144, quoting Exhibit CUB-44.

inflation adjustment for labor. MNSC maintains that by forecasting wage growth per employee, rather than for the workforce as a whole, the Company excludes any accounting of workforce productivity improvement.[412]

DTE's reply brief reiterates that its labor inflation rates are reasonable, emphasizing that its pay practices are not completely driven by inflation, noting that in 2022, when CPI inflation was at 8.0%, the Company's wages did not increase by that amount. DTE further contests the Attorney General's reliance on the labor component of the CPI-U arguing that Mr. Coppola "failed to provide an assessment of how CPI-U is impacted by any labor and wage increases, or what the labor cost increases embedded in CPI-U might be, or how the labor and wage increase contained in CPI-U compare to the Company's labor or wage increases."[413]

As discussed above, in DTE's most recent prior rate case, the Commission adopted the Company's composite inflation rate, finding it reasonable for DTE to use internal sources for projecting labor inflation, coupled with the use of the CPI-U for non-labor inflation. The Commission also directed the Company "to provide further detail on the company-specific dynamics that justify rejection of the CPI-U or a similar widely-used rate for labor costs." Based on the record here, this PFD finds that the Company failed to provide this information as directed.

DTE again relied on collective bargaining agreements for represented employees, plus pay progression, and standard 3% pay increases for non-represented employees in developing the labor portion of its inflation rates. This PFD finds that these increases,

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[412] MNSC brief, 144-145.
[413] DTE reply, 11-12.

based on historical wage increases, are generally not contested by the parties, except for MNSC.

In addition to DTE's failure to provide additional support for company-specific labor inflation, another significant issue that has emerged is the fact that DTE assumes no offset for workforce productivity in its labor inflation projection, based either on internal or external metrics. As MNSC witness Bunch testified, by significantly reducing its total number of employees since 2019, "DTEE has harvested labor productivity benefits in an inflationary wage environment" without including any productivity offset, to the detriment of ratepayers.[414]

This PFD notes that Mr. Bunch's productivity offset is taken from the BLS which, like the CPI-U inflation rates – which DTE uses for its proposed non-labor inflation rates and for its non-represented employee component of its labor inflation rates – *see* discussion, *infra* -- are historical data.[415] DTE does not propose an alternative productivity offset, nor does DTE indicate why the Michigan private non-farm worker category is inapplicable or what alternative category from the BLS is more appropriate here. Indeed, and most significantly, this PFD notes that DTE does not rebut or challenge generally the applicability of a labor productivity offset.

And while ABATE focuses on overall O&M expenses, the Company does not dispute the data presented in Tables JAY-1 and JAY-2, which show that total O&M expense has increased, if at all, at a rate less than inflation. While numerous factors

[414] 5 Tr 4841.
[415] 5 Tr 4843; Ex. CUB-43.

influence actual O&M expense, one of those factors is likely to be increased productivity and workforce efficiency.

That said, this PFD is not persuaded by the composite inflation rates proposed by MNSC at this time, specifically questioning the inputs to MNSC's calculation of past labor inflation of 0.23%. Finding both DTE's position and that of MNSC unreasonable concerning appropriate blended inflation rates, this PFD recommends that the Commission adopt the updated CPI-U inflation rates of 2.9% for 2024, 2.7% for 2025 and 2.4% for 2026 as presented by MNSC, which, as the Attorney General points out, include wage inflation.

3. Base Capital and Constant Dollar Averaging

Mr. Chiu explained that there are certain base capital investment categories that respond to emergent or specific customer needs including planned replacements for Customer Connections, Relocations, Others, and reactive replacements for Emergent Replacements for Storm, Non-Storm, and Substation Reactive, as shown in Exhibit A-12, Schedule B5.4, p. 1, and Exhibit A-23, Schedule M4.[416] These base capital investments are generally calculated based on three- or five-year historical average expenditure amounts, updated by inflation.

Mr. Hill testified that the Company's revenue requests for Emergent Replacements and Customer Connections, Relocations, and Other are based on CDA, which converts historical nominal dollars to real dollars and then averages those real costs as the basis for future projections. The use of this practice has been disputed in DTE's prior rate cases

[416] 3 Tr 1091-1092.

primarily as applied to Emergent Replacements capital costs and O&M healthcare expenses. In this case DTE is using CDA for Emergent Replacements; Customer Connections, Relocations and Other; and Restoration O&M. This PFD addresses the propriety of CDA followed by additional recommended disallowances for specific Base Capital projects or programs.

4. Constant Dollar Averaging

DTE witness Lyons testified that CDA of historical costs is a necessary step in developing cost forecasts because inflation over time reduces the purchasing power of goods and services. According to Mr. Lyons, inflation has increased substantially over the historic January 2019 through December 2022 period as reflected by an 18% increase in the CPI.[417] He equated the presence of inflation with a decline in purchasing power, such that doing the same volume of work in 2023 as was done in 2019 would cost approximately 18% more due to inflation.[418] He explained that CDA adjusts for this decline in purchasing power and maintains the ability to purchase the same units of materials and labor over time.[419]

Mr. Lyons asserted that CDA is a recognized practice in cost forecasting and planning. According to him, the Department of Defense (DoD) and the Government Accountability Office (GAO) rely on inflation-adjusted historical costs to achieve cost forecasting integrity and fiscal accountability.[420] He also testified that CDA is used in the

[417] 4 Tr 3165, Figure 1.
[418] 4 Tr 3166.
[419] Id.
[420] 4 Tr 3166-3167.

utility industry by SDG&E in California, National Grid in Massachusetts, PECO in Pennsylvania, and Atco Electric in Alberta, Canada.[421]

DTE witness Bruzzano testified that the Commission's decision in Case No. U-21534 to reject CDA in the projection of average Emergent and other Base Distribution capital expenditures will result in insufficient funding.[422] Mr. Lyons added that the Commission's denial of CDA was based on a concern that the evidence did not demonstrate an upward inflation trend given that there was decreased spending in some historical years.[423] He explained, however, that in those years of reduced spending, it occurred because of a reduction in work volumes due to minimal storm activity and that there was still an upward trend in material and labor costs within those years.[424] He testified that from 2020 to 2024, common materials used for Emergent Replacements have increased well above the increase in CPI-U, for example, the cost of overhead transformers has increased by more than 300%.[425] And he maintained that the same is true for distribution operation contract labor rates, noting that contract labor rates for overhead workers will be 30% higher in 2026 than 2019, based on collective bargaining agreements.[426]

Staff and several intervenors opposed DTE's use of CDA, referring to the Commission's rejection of the method in Case No. U-21534. Staff witness Durfee testified that the Commission found the application of CDA to Emergent Replacement capital

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[421] 4 Tr 3167-3168, Table 1.
[422] 3 Tr 982-983.
[423] 4 Tr 3168-3170, Table 2.
[424] 4 Tr 3170-3171, Table 3.
[425] 4 Tr 3171-3173, Table 4.
[426] 4 Tr 3173-3174, Figure 2.

expenditures unwarranted and DTE's proposal unconvincing.[427] She asserted that DTE has still failed to provide a convincing argument, testifying that within Emergent Replacements the Storm and Substation Reactive categories showed a downward movement in both 2020 and 2022, and the Non-Storm category showed downward movement in 2020.[428]

Mr. Coppola maintained that the circumstances in this case are the same as they were in DTE's last rate case and there is still no compelling reason to approve the Company's use of CDA.[429] He testified that there is always the possibility that forecasts will be lower than actual costs and that if DTE is seeking to retroactively recover some additional inflation-related costs via CDA, it would be misguided and wholly inappropriate.[430] He added that although there may be a mismatch between forecasted and actual costs in a rate case, actual, prudent costs are eventually recovered in the next rate case.[431]

Mr. Coppola stated that DTE's discovery responses are telling, testifying that DTE acknowledged that it has not done any research into the use of CDA for its internal budgets and programs and is not aware of any non-utility companies that use the method to set prices on goods.[432] Further he asserted, DTE had no evidence that the DoD uses the method to increase payments to its suppliers or that CDA is widely used in business transactions with financial consequences, such as ratemaking.[433]

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[427] 5 Tr 5272-5273.
[428] 5 Tr 5273.
[429] 4 Tr 3433-3434.
[430] 4 Tr 3429-3430.
[431] 4 Tr 3430.
[432] 4 Tr 3430-3431.
[433] 4 Tr 3431.

Mr. Coppola disagreed with the claim that CDA is needed because inflation reduces purchasing power. He testified that the volume and mix of goods and services can change every year depending on the number of storms and the materials that need to be replaced and adjusting historical costs that already reflect the inflation in that year with a general inflation factor that occurred in a subsequent year has no relevance and is simply an artificial exercise to escalate the amount of the requested rate increase.[434]

Ms. York testified that in Case No. U-21534 the Commission found that any inflation experienced by the Company in prior years is already reflected in actual historical amounts.[435] She explained that for Emergent Replacements, the uninflated five-year average historical capital expenditure amount recognizes that increases in material and labor costs have occurred and that there is uncertainty around the level of storm activity and work volume in the future test year.[436]

MNSC witness Jester also disagreed that CDA is necessary to address a loss of purchasing power, positing that "nominal cost averaging over a few years during which there is inflation and then nominal cost averaging in the next rate case over a similar number of later years will produce a higher cost average, by the amount of inflation, adjusted for productivity gains, than actually occurred."[437] He also asserted that CDA fails to account for the continuous improvement in labor productivity seen in the rest of the economy and is not appropriate because work volume varies significantly from year to year.[438]

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[434] 4 Tr 3432-3433.
[435] 4 Tr 3260.
[436] 4 Tr 3261.
[437] 5 Tr 4763-4764.
[438] 5 Tr 4764.

Mr. Jester testified that while regulators have accepted CDA for certain capital additions, many of these are in the context of performance-based ratemaking (PBR), adjusting rates subject to a revenue cap, allowing for inflation adjustments while accounting for productivity offsets, and including consumer dividends.[439] He recommended that the Commission either disapprove of CDA for distribution capital spending in this case, or establish a contested case process for Distributed Grid Planning (DGP) with the implementation of a PBR approach for distribution capital spending.[440]

In rebuttal, Mr. Hill countered that DTE used historical averages adjusted by CDA to forecast Emergent Replacements and Customer Connections, Relocations & Other in its five prior electric rate cases (Case Nos. U-20162, U-20531, U-20836, U-21297, and U-21534).[441] He testified that he and other DTE witnesses provided substantial and compelling evidence of volatility and upward cost trends to support CDA in the instant case.[442] As for Mr. Jester's claim that CDA fails to account for labor productivity as occurs in the rest of the economy, Mr. Hill testified that Company witness Fix provided evidence to the contrary, and further that Mr. Jester's analysis was flawed because it only considered internal labor costs, failed to provide any evidence linking DTE's operations to general economic trends, and did not provide quantifiable evidence to show that productivity gains could offset the significant increases in contract labor costs.[443] He further countered that Mr. Jester's attempt to link CDA to the DGP and PBR lacks a clear basis and is unsupported by evidence. Further he asserted that this proposal undermines

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[439] 5 Tr 4770.
[440] 5 Tr 4770
[441] 4 Tr 2801-2804.
[442] 4 Tr 2807-2808.
[443] 4 Tr 2808-2811.

Mr. Jester's objections to constant dollar averaging, "either CDA is appropriate, or it is not. Its validity is not contingent," he stated.[444]

Mr. Lyons emphasized that his direct testimony clearly addressed the Commission's concerns about CDA and he provided sufficient evidence that Emergent Replacements and Customer Connections, Relocations & Other expenditures were both volatile and consistently trending upward.[445] He asserted that Ms. Durfee did not consider the reduction in work volume and expenditures due to the reduction in customer interruptions as an explanation for the reduction in Emergent Replacement costs in 2020 and 2022.[446]

Mr. Lyons reiterated that CDA is only used to develop more accurate cost forecasts by normalizing or converting historical (nominal) dollar values to constant (current) dollar values, and DTE is not seeking to retroactively recover additional inflation related costs.[447] And he maintained that the Commission has already acknowledged that the method would not result in a duplication of inflationary costs.[448] He refuted Mr. Coppola's suggestion that CDA is simply an artificial exercise to enlarge the requested rate increase, explaining that adjusting historical costs with a general inflation factor that occurs in subsequent years is highly relevant because it reflects the change in price levels from the initial year to the subsequent years and if the inflation adjustment was not applied, it would understate the cost of the product in future years.[449]

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[444] 4 Tr 2812.
[445] 4 Tr 3181-3182.
[446] 4 Tr 3184.
[447] 4 Tr 3184-3185.
[448] 4 Tr 3185.
[449] 4 Tr 3185-3186.

Mr. Lyons provided further testimony on other entities that use CDA, stating that the DoD uses historical inflation adjustments to provide accurate information and realistic estimates of costs for acquisition programs as well as in routine practice to support cost analysis.[450] He noted that its importance in accurately forecasting costs in business settings is recognized by the Association for the Advancement of Cost Engineering (AACE) International.[451] Mr. Lyons maintained that the California Public Utilities Commission found CDA "reasonable."[452] And he noted that PECO's use of constant dollar averaging has been approved after examination by the parties in settlement agreements during the past decade.[453]

Mr. Lyons countered Mr. Jester's argument that nominal dollar averaging does not lose purchasing power over time in a cumulative sense, stating that nominal dollar averaging understates the real level of costs when older year costs are included without inflation adjustment because inflation erodes the comparability of dollar value over time.[454] He disagreed with Mr. Jester's concern that the work varies too significantly to justify the upward trend in costs, stating that labor and material costs have demonstrated substantial increases since 2020.[455] Further, he asserted that the year-to-year variation in storm costs reflects the inherent unpredictability of weather events, not the methodology used to calculate historical averages.[456] Finally, in response to Mr. Jester's

[450] 4 Tr 3186-3188.
[451] 4 Tr 3188-3189.
[452] 4 Tr 3189.
[453] 4 Tr 3190.
[454] 4 Tr 3192-3193.
[455] 4 Tr 3194.
[456] 4 Tr 3194-3195.

proposal to tie CDA to PBR, Mr. Lyons asserted that the importance of utilizing CDA of historical costs is relevant and important regardless of the ratemaking mechanism.[457]

In briefing, DTE contends that its witnesses presented clear evidence showing both the presence of stubbornly high inflation and upward trends in materials and labor costs.[458] The Company argues that CDA will put the Company in a better position to identify and recover its actual costs, which is a critical component of the financial strength necessary to provide reliable utility service.[459]

In her brief, the Attorney General spells out the practical implications of DTE's use of CDA, arguing that it results in 2019 costs being inflated by 1.2% for 2020 inflation, then again by 4.7% for inflation in 2021, then again by 8.0% for inflation in 2022, and again by 4.1% for inflation in 2023, and this process is repeated for all subsequent historical expenditures.[460] She argues that DTE's purported evidence that Emergent Replacement material costs increase year over year is based on a list of ten items representing only $26.4 million in capital expenditures over 2019 to 2024, which represents less than 1% of the total Emergent Capital expenditures of $2.86 billion.[461] As for labor costs, she argues that escalating labor rates is not a new phenomenon and any labor rate increases are reflected in the actual capital expenditures for emergent work completed each subsequent year.[462]

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[457] 4 Tr 3195.
[458] DTE brief, 29.
[459] DTE brief, 29.
[460] Attorney General brief, 19.
[461] Attorney General brief, 24.
[462] Attorney General brief, 25.

The Attorney General argues that DTE's citations to DoD materials are out of date, and any reference to the DoD using CDA appears to be no more than a simple forecasting exercise, with no financial or business implications.[463] She also notes that that the AACE is not a regulator and is likely not involved in utility rates cases such that their proposed practices have no relevance to ratemaking.[464] And she maintains that there is no evidence to show that Pennsylvania Utilities Commission explicitly approved the use of CDA by PECO. She reasserts that DTE is using as an opportunity CDA to inflate its projected costs far beyond any reasonable measure and it is telling that the Company does not use it in its own internal forecasting and budgeting.[465]

Staff, MNSC, and ABATE maintain their positions in their respective briefs. MNSC further contends that DTE's claim that CDA has been applied in its five prior rate cases omits important context from the previous cases and ignores that the Commission rejected it for Emergent Replacements in its last rate case.[466] ABATE further argues that DTE did not demonstrate support for CDA because, among other things, it did not explain whether its utility examples use the method as DTE is proposing, that is to further increase the inflation-adjusted historical average level by additional future projected inflation rates to arrive at a test year number.[467]

The parties' reply briefs generally restate their prior arguments and do not add anything new to the discussion, with the exception of the Attorney General whose reply brief notes that the Federal Reserve cut interest rates in September 2025 and again on

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[463] Attorney General brief, 26.
[464] Attorney General brief, 27.
[465] Id.
[466] MNSC brief, 8-10.
[467] ABATE brief, 27-28.

October 29, 2025. She argues that this further weakens DTE's arguments that it needs "bloated interest rates and novel calculation methods, such as CDA, which only serve to drive up rates."[468]

This PFD recognizes that the Company's use of CDA has been disputed in DTE's previous rate cases. It is noted that the arguments for and against the method have generally evolved and the Commission's orders have been somewhat inconsistent. The Commission itself recognized these inconsistencies in Case No. U-21534.[469]

In Case No. U-20836, the Commission approved CDA for Emergent Replacements but required DTE to present further evidence in its next rate case on the effect of the Company's capital investments on productivity benefits and any continued need for inflationary adjustments to historical data.[470] As for O&M healthcare costs, CDA was rejected, the Commission agreeing with the ALJ that it was not convinced that the method was appropriate.[471]

In the following case, Case No. U-21297, the ALJ recommended rejecting CDA for Emergent Replacements because DTE failed to present evidence on productivity impacts to inflationary pressures. But the Commission did not adopt the ALJ's recommendation, finding that there were only two months between the U-20836 order and the filing of U-21297. However, the Commission expected the Company to present the evidence in its next rate case.[472] For healthcare O&M expenses, CDA was again rejected, the

[468] Attorney General reply, 11-12.
[469] January 23, 2025 order in Case No. U-21534, p. 71.
[470] November 18, 2022 order in Case No. U-20836, p. 63.
[471] November 18, 2022 order in Case No. U-20836, pp. 286-288.
[472] December 1, 2023 order in Case No. U-21297, p. 76.

Commission agreeing with the ALJ that DTE "insufficiently demonstrated that its proposed constant dollar normalization will not result in compounded inflationary increases."[473]

In Case No. U-21534, the Commission rejected CDA for Emergent Replacements and other capital expenditures, as well as for O&M healthcare expenses.[474] The Commission determined that DTE did not sufficiently demonstrate that historical costs actually increased by the inflation factors DTE applied, but the Commission stated "that its response to the use of constant dollar averaging might be different if the evidence showed that these expenditure categories are both volatile and consistently trending upwards."[475] As for the analysis of the offsetting effects of significant capital investments on inflation, the Commission found that DTE "continues to fail to produce a convincing case" for any continued need for inflationary adjustments to historical data in this cost category for emergent replacements in the future and that in the Company's next rate case, "DTE Electric shall present evidence on the continuing need for any inflationary adjustment to these expenditures."[476]

DTE's arguments to apply CDA in the instant case focus on the Commission's statement in Case No. U-21534 that its "response might be different" if there were evidence that spending expenditures were "both volatile and consistently trending upwards." DTE argues that Emergent Replacement costs are volatile and that it presented evidence showing significant increases in unit costs for materials and labor over the historical five-year period. DTE further contends that these upward trends in unit

[473] December 1, 2023 order in Case No. U-21297, p. 232.
[474] January 23, 2025 order in Case No. U-21534, p. 73, 254
[475] January 23, 2025 order in Case No. U-21534, p. 73.
[476] January 23, 2025 order in Case No. U-21534, p. 74.

costs are masked in some historical years because of reduced storms and the need for less materials and reduced work volumes, that is that without the volatility of the costs due to the unpredictability of weather, the costs would have increased because of inflation.

However, this PFD finds DTE's reasoning and focus on a small number of unit costs unpersuasive. When noting upward trends, the Commission specifically referred to trends in total costs for a given category, not unit costs. DTE's reasoning ignores the Commission's finding that it may change its decision if there were volatility "and" an upward trend in costs, that is that the Commission may approve CDA if the evidence shows upward trending costs "despite" the volatility. The evidence on the record does not demonstrate this, as noted by Staff, within Emergent Replacements the Storm and Substation Reactive categories showed a downward movement in both 2020 and 2022, and the Non-Storm category showed downward movement in 2020. It is noted that downward trends were specifically noted by the Commission when it rejected CDA in Case No. U-21534.

Further, this PFD observes that DTE again failed to respond to the Commission's continuing directive that the Company provide an analysis for the need for CDA given productivity gains from significant capital investments. As for DTE's argument that removing CDA will result in underfunding these expenditures, this PFD finds that if in future rate cases DTE continues to propose the use of CDA, it should provide discrete evidence of how its expenditures have been underfunded by the absence of CDA.

Based on the foregoing, this PFD finds that CDA is not supported and historical inflation adjustments should be removed from all Base Capital programs.[477] Using DTE's historical inflation adjustments shown in Exhibit A-12, Schedule B5.4, pp. 3-6, and the 2024-2026 inflation amounts discussed above, this PFD calculates a reduction of $68.481 million for 2025 and $66.483 million for 2026 for CDA applied to all applicable Base Capital programs.

In light of the above determination, this PFD declines to adopt MNSC's recommendation to tie CDA to PBR and the DGP. Other adjustments related to certain Base Capital programs are discussed below.

5. Emergent Replacements

The Emergent Replacements portion of Base Capital Programs includes Storm, Non-Storm, and Substation Reactive programs. Mr. Hill described expenditures for the Storm category to include labor and material costs required to restore the distribution and subtransmission systems from damage and outages occurring during events meeting the threshold definition of a storm, which is greater than 760 customer outage events impacting greater than 200 distinct circuits sustained for longer than one hour.[478] He described typical storm material expenditures to include transformers, poles, wire conductors, crossarms, line hardware, capacitors, reclosers, switches, and cutouts, which are most often damaged by weather and tree impacts.[479] Mr. Hill testified that Storm

[477] Emergent Replacements; Connections and New Load; Relocations; Electric System Equipment; NRUC and Improvement Blankets; and General Plant, Tools & Equipment, and Miscellaneous.
[478] 4 Tr 2768.
[479] 4 Tr 2774.

expenditures for 2025 and 2026 are projected at $276.4 million and $284.9 2 million, respectively, after applying historical inflation.

Mr. Hill testified that Non-Storm expenditures are used to restore power to the distribution and subtransmission system and/or return to normal operating configuration during non-storm conditions, which are conditions that do not meet the threshold definition of a storm event. The category also includes equipment that fails for other reasons, not related to weather.[480] Mr. Hill testified that Non-Storm expenditures for 2025 and 2026 are forecasted at $233.4 million and $254.2 million, respectively.[481] He added that DTE is forecasting additional Corrective Maintenance replacements in the Non-Storm category as discussed by DTE witness Robinson.[482]

Mr. Hill testified that the Substation Reactive category includes investments required to perform emergency replacements for substation equipment.[483] He pointed out that the category includes non-electrical substation equipment failures and that DTE plans to spend $8 million in 2025 to repair three substations: (1) the Troy substation, which experienced a structural failure of a side wall during a 2024 wind weather event; (2) the Chestnut substation side wall; and (3) the Imlay substation site, which needs replacement of steel structures and foundations due to steel erosion and loss of structural integrity to several connecting plates and support brackets.[484] Mr. Hill testified that the Company is

[480] 4 Tr 2776.
[481] 4 Tr 2778; Exhibit A-12 Schedule B5.4, page 2.
[482] 4 Tr 2779.
[483] 4 Tr 2779-2780.
[484] 4 Tr 2781-2782.

forecasting 2025 and 2026 Substation Reactive expenditures at $56.6 million and $59.9 million, respectively, after applying historical inflation.[485]

Staff witness Durfee and Attorney General witness Coppola recommended disallowances for Emergent Replacements based on the removal of CDA, as discussed above. Mr. Coppola's forecasted amounts, $486,712,000 for 2025 and $497,995,000 for 2026 (after the Strategic Spend reductions), were based on the uninflated 2020-2024 five-year average and CPI-based future inflation factors and included the removal of DTE's adjustments for non-storm corrective maintenance, substation facility repair, and substation corrective maintenance because he asserted, they were not supported or adequately justified.[486]

ABATE witness York objected to the use of the 2019-2023 average. In her view, it is inappropriate to include 2021 in the average because the year was unprecedented in terms of storm-related frequency, intensity, and number of customer outages.[487] She suggested that if the Commission prefers to average five years, then it should use 2019-2020 and 2022-2024 instead of 2019-2023. She asserted that using 2021 data as the basis for future projections would only serve to unnecessarily inflate DTE's projected capital expenditures and she added that there is no evidence that her alternative five-year period would significantly underestimate Emergent Replacement spending during the bridge period or projected test year.[488]

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[485] 4 Tr 2780-2781; Exhibit A-12 Schedule B5.4, page 2.
[486] 4 Tr 3436-3437.
[487] 4 Tr 3258.
[488] 4 Tr 3259.

In rebuttal, Mr. Hill objected to Mr. Coppola's recommended disallowances. Nevertheless, he testified that if the Commission adopts them, they should be updated as they omit spending for corrective maintenance in the Non-Storm category and for corrective maintenance and substation facility repairs in the Substation Reactive category.[489] Mr. Hill also testified that adopting Mr. Coppola's proposal to use the 2020-2024 average increases the Company's original proposal by $19.2 million for 2025 and $19.8 million for 2026.[490]

As for Ms. York's recommendation to remove 2021 from the calculation of the historical average, Mr. Hill asserted that the five-year average is intended to account for weather volatility and excluding the highest storm years, as Ms. York recommends, would undermine its intended use.[491] And he maintained that while the storms in the Summer of 2021 were historic they were not unprecedented, noting that in 2023 the Company experienced the worst ice storm in its history along with six summer tornadoes.[492]

In surrebuttal, Mr. Hill refuted Mr. Coppola's assertion that DTE failed to support its projected spending for corrective maintenance and substation facility repairs. He specifically noted that footnote 2 in Exhibit A-12, referred to by Mr. Coppola, is unrelated to corrective maintenance requests and that his direct testimony supported substation facility repairs, while Company witness Robinson supported the corrective maintenance increases.[493]

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[489] 4 Tr 2815-2817, Tables 1 and 2; Exhibit A-52, Schedule SS-2.
[490] 4 Tr 2817-2818; Exhibit A-52, Schedule SS-1.
[491] 4 Tr 2818-2819.
[492] 4 Tr 2819.
[493] 4 Tr 2835-2839.

The parties' briefs generally repeat and support their respective witnesses' testimony. The Attorney General makes clear that Mr. Coppola intended to exclude corrective maintenance and substation facility repair from the Non-Storm and Substation Reactive categories, because these costs were not explained, justified or otherwise supported by either Mr. Hill or Mr. Robinson.[494] Furthermore, she opines that it is unclear why an additional $8 million is needed for substation facility repair above the recurring capital spending, and she notes that it was not included in the Company's projections in Case No. U-21534.[495]

In reply, DTE argues that the Attorney General's recommended disallowance of $13,654,000 for 2026 corrective maintenance within the Non-Storm category should be rejected because it was not justified or explained in Mr. Coppola's direct testimony and the Attorney General sought to explain it for the first time in briefing. DTE contends that this type of "last-minute, unsupported criticism" is barred by the standard established by the Commission in 2010.[496]

The Company maintains that the same reasoning should be used to reject the Attorney General's disallowance of $8 million in 2025 for substation facility repairs within the Substation Reactive category, as she argues for the first time in her initial brief that the $8.0 million might be redundant. DTE also argues that its witness supported the need for $8.0 million in substation facility repairs.[497] The other parties did not present any new arguments in their respective reply briefs.

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[494] Attorney General brief, 27-28,
[495] Attorney General brief, 28-29.
[496] DTE reply, 63-64; January 11, 2010 order in Case Nos. U-15768 and U-15751, pp 37-38.
[497] DTE reply, 64-65.

Although it may be appropriate to use the historical average of the most recent five-year period of 2020-2024, as proposed by the Attorney General, given the lack of clarity in the record on how DTE and the Attorney General derived their updated averages, this PFD finds that the recommendation to update the average to include 2024 costs should be rejected for Emergent Replacements.

This PFD nevertheless agrees with the Attorney General that DTE did not fully support the corrective maintenance and substation facility repair costs that were included as separate line items in cost categories that are significant. The Company stated what these expenditures were for, but it otherwise failed to explain why they should not simply be included as part of the five-year average of Non-storm or Substation Reactive spend.

Based on the above, this PFD recommends adoption of the Attorney General's disallowance of $13.7 million for 2026 for Non-Storm corrective maintenance, and $8 million and $9.85 million for facility repair and corrective maintenance under the Substation Reactive Base Capital program.

As for ABATE's recommendation to exclude 2021 from the five-year average, the Commission has twice previously rejected this recommendation, stating in the U-21534 order that "high variations in weather are becoming the norm and the Commission supports the use of the five-year average." As such, ABATE's recommendation to exclude 2021 costs is again rejected.[498]

6. Other Base Capital Adjustments

[498] January 23, 2025 order in case No. U-21534, p. 76.

Mr. Hill presented DTE's projected expenditures for Customer Connections, Relocations, and Other in Exhibit A-12, Schedule B5.4. He testified that these expenditures are broken down into six subcategories: (1) Customer Connections and New Load (including utility make-ready for new EV load); (2) Relocations; (3) Electric System Equipment; (4) Normal Retirement Unit Change-out (NRUC) and Improvement Blankets; (5) General Plant, Tools & Equipment and Miscellaneous (including meters); and (6) Public Lighting Department Project.[499] Mr. Hill stated that DTE's forecasts in this category are generally based on CDA applied to the three-historical average with the exception of two unique and discrete projects: I-375 relocation and Incremental Infrastructure for EV.[500] He also noted that the forecasts for 2025 and 2026 have been updated to reflect the implementation of new line extension CIAC.[501]

Staff and Attorney General witnesses had the same concerns about the use of CDA in Customer Connections, Relocations, and Other as for the Emergent Replacement category, as discussed and resolved above. Ms. Durfee noted downward movements in spending in 2022 and 2023, and Mr. Coppola recommended adjusting the Company's forecasts by using the three-year average from 2022-2024, instead of 2021-2023.[502] His specific recommendations for subprogram spending are discussed below.

The parties' briefs generally reiterate the testimony and recommendations of their respective witnesses. The Attorney General contends that DTE appears to accept the use of 2022-2024 for the three-year average, as opposed to the 2021-2023 average. She

[499] 4 Tr 2784.
[500] 4 Tr 2785.
[501] 4 Tr 2789.
[502] 4 Tr 3437-3438.

recommends that the Commission increase the Company's forecasted capital spending for 2025 by $1,745,000 and reduce the 2026 capital expenditures by $8,806,000.[503]

As noted above, this PFD finds that the Attorney General's recommendation to use the 2022-2024 updated three-year average, instead of the 2021-2023 average, should be denied, in light of the complexity of the calculations and lack of clarity in the record.

Under these remaining categories of Base Capital expenditures, the Attorney General raises issues related to (1) the I-375 relocation project; and (2) utility make-ready (UMR) capital spending for EVs. In addition, Staff recommends a disallowance for electric meters under the Electric System Equipment category. These adjustments are addressed below.

a. I-375 Relocation Project

Mr. Hill testified that the Company's forecasts for the Relocation subcategory include the I-375 Relocation project, which will relocate distribution infrastructure located in the I-375 below-grade freeway corridor that is being replaced with a grade-level boulevard. He explained that the Company began the project in 2023 and spent $6.3 million that year, as well as $6.3 million in 2024.[504] He testified that the Company's forecasts for the project are $15 million for 2025 and $15 million for 2026.[505]

Mr. Coppola testified that in a discovery response DTE reduced the expected capital expenditures for the project to $8.4 million for 2025 and $12 million for 2026.[506] He also testified that the Detroit News reported that the Governor is reevaluating the entire

[503] Attorney General brief, 31.
[504] 4 Tr 2788-2789; Exhibit A-12, Schedule B5.4.
[505] 4 Tr 2789.
[506] 4 Tr 3444.

project in light of significant cost overruns and recent community pushback.[507] In his view, it is likely that the relocation will be put on hold and the forecasted capital expenditures will not occur. He recommended that the entire $30 million ($15 million in 2025 and $15 million in 2026) of forecasted capital spending be removed.

In rebuttal, Mr. Hill urged the Commission to reject Mr. Coppola's removal of the 2025 and 2026 projected expenditures for the I-375 Relocation project. He stated that the Company received a notice to vacate from MDOT and is required to proceed with the project and further that it is unreasonable to expect that no work will be performed in 2025 and 2026.[508] He recommended that the Commission accept the Company's discovery responses indicating that it will spend $8.4 million in 2025 and $12.0 million in 2026 for this project.[509]

DTE's brief restates Mr. Hill's testimony and highlights that the Company did not use CDA for its I-375 Relocation cost projections.[510] The Attorney General's brief reiterates Mr. Coppola's testimony and responds to Mr. Hill's rebuttal. She argues that the Company did not explain what a "notice to vacate" means or why the Company must proceed with the project. She contends that there are "huge discrepancies" between the Company's original projections and what it notes in rebuttal, such that it is unreasonable to approve any cost recovery for the project. She reasserts Mr. Coppola's recommendation that the Commission remove $12,250,000 for 2025 and $11,785,000 for

[507] 4 Tr 3445; Exhibit AG-4.
[508] 4 Tr 2826-2827.
[509] 4 Tr 2827.
[510] DTE brief, 85, 87.

2026 from the Company's forecasted capital expenditures in the Relocations subcategory.[511]

In reply, DTE emphasizes that whatever the timing and circumstances of the I-375 relocation project, the broader I-375 construction project is being controlled by the MDOT and it would be arbitrary and unreasonable for the Commission to penalize DTE for the State of Michigan's changing construction plans.[512]

In her reply, the Attorney General argues that DTE's forecasts for this project are uncertain, as demonstrated by the Company's reduced forecasts, and it is therefore not reasonable or prudent to recover these costs at this time.[513]

This PFD declines to adopt the Attorney General's recommended removal of the entire I-375 Relocation projected spending for 2025 and 2026. The notice to vacate is a legal document requiring DTE to remove its infrastructure from its current location and while the Detroit News article presented by the Attorney General indicates a delay and reevaluation of the project it does not suggest that the project will be terminated. This PFD accepts the Company's reduced spending projections of $8.4 million in 2025 and $12.0 million in 2026 for this project. This results in a removal of $6.6 million from the Company's original forecast for 2025 and a removal of $3 million from its 2026 forecast.

b. Utility Make-Ready for Electric Vehicles

Mr. Hill testified that Customer Connections and New Load expenditures include Incremental Infrastructure for EVs, explaining that this incremental capital is for

[511] Attorney General brief, 35.
[512] DTE reply, 65.
[513] Attorney General reply, 31.

construction of EV charging infrastructure and is a subset of the Company's Transportation Electrification Plan (TEP).[514]

Mr. Coppola forecasted Small Load Growth, Customer Connections, and New Business Projects using the uninflated three-year average from 2022-2024 and applying CPI-inflation rates for 2025 and 2026.[515] He also removed incremental capital expenditures of $9.2 million for 2025 and $18.6 million for 2026 for EV UMR customer installations, asserting that the current environment and demand for EVs does not predict that EV registrations will grow, contrary to DTE's premise for the spending.[516]

Mr. Coppola testified that DTE provided its EV forecast through discovery, noting declining numbers. Specifically, in Case No. U-20836, DTE had forecasted 68,325 new EV registrations for 2025 and 78,963 registrations for 2026, but now only forecasts 26,787 new registrations for 2025, and 37,525 for 2026.[517] To illustrate, Mr. Coppola presented a table in his testimony setting forth the number of annual new registrations and cumulative EV adoptions, with the rate of new vehicle registrations having slowed substantially in the past year.[518]

Based on this information, Mr. Coppola posited that DTE has a track record of overestimating the annual registration and adoption of EVs by its customers and he noted that as of 2024, EVs have not been selling at anticipated levels because of many factors including customer dissatisfaction with driving range and reliability concerns.[519] He stated

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[514] 4 2786-2787
[515] 4 Tr 3439-3440.
[516] 4 Tr 3440-3443.
[517] 4 Tr 3441-3442.
[518] 4 Tr 3441-3442.
[519] 4 Tr 3441-3443.

that while some level of EV sales will continue, the increase in UMR installations over the actual base amount in 2024 is not likely to occur.[520] He further asserted that DTE could not provide the actual costs of UMR installations in prior years so it is impossible to establish whether the historical base capital expenditures for UMR assumed by the Company are accurate and whether any incremental expenditures are necessary.[521]

In contrast, MEIU witness Schuster generally expressed support for DTE's long-term EV adoption forecast, noting that, while current economic and political conditions might stymie U.S. EV adoption, growing international markets would require American automaker expansion of EV production.[522] She opined that EV purchases would continue to grow as range and price gained greater parity with internal combustion engine (ICE) vehicles.[523] She cited Governor Whitmer's executive directives to transition the State's light duty (LD) fleet to zero emission vehicles (ZEVs) by 2033 and medium- and heavy-duty (MHD) fleet vehicles by 2040. She also noted coordination with higher education institutions and local units of government to transition to ZEVs, as well as the steps being taken towards this goal, as representing substantial EV adoption growth for which the state's utilities will need to plan.[524] Additionally, Ms. Schuster cited EGLE's Clean Fuel and Charging Infrastructure (CFCI) grant program, and MDOT's award of National Electric Vehicle Infrastructure (NEVI) program funds, which she stated were to be continued by the federal government, along with utility rebates, as improving the "visibility

[520] 4 Tr 3443.
[521] 4 Tr 3441.
[522] 5 Tr 3930-3940.
[523] 5 Tr 3940-3942.
[524] 5 Tr 3942-3943.

of new and existing charging opportunities," and "instilling greater confidence" that EVs will be supported.[525]

Regarding DTE's EV UMR funding request, Mr. Lueker stated that "there is ample evidence to support the Company's projections of EVs."[526] He maintained that the Company believes that the EV market will continue to grow, which is an opinion shared by external experts. He added that while the elimination of federal EV tax credits makes future EV registrations somewhat uncertain for 2026, the Company is currently ahead of its 2025 forecast and it is likely that EVs will remain in DTE's service area and require charging support.[527] Mr. Foley noted that the Company stands by its EV forecasts and disagrees with Mr. Coppola's recommended EV UMR disallowances.[528]

DTE's brief refers to Mr. Foley's and Mr. Lueker's testimony supporting its requested EV UMR spending.[529] In her brief, the Attorney General recaps Mr. Coppola's testimony and argues that the termination of the federal tax credits has driven higher EV registrations and is almost certain to make DTE's 2026 forecasts overestimated. Accordingly, she contends that Mr. Coppola's projections for 2026 are much more likely to be reasonable than DTE's outdated projections.[530]

In reply, the Company argues that even if EV growth slows in response to evolving federal policy, the Company's service area requires new charging infrastructure.[531]

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[525] 5 Tr 3944-3945.
[526] 3 Tr 1371.
[527] 3 Tr 1371-1372.
[528] 4 Tr 2668.
[529] DTE brief, 214.
[530] Attorney General brief, 31-34.
[531] DTE reply, 199.

In her reply brief, the Attorney General points out that DTE appears to concede that EV adoption will likely decrease due to the sunsetting of the EV tax credits, as it states that it will "commit to evaluating such impacts prior to filing its next TEP."[532] She argues that this belies the Company's UMR forecasts, which are based future increases in EVs. She argues that, "[t]here is no need to approve capital expenditures in this case that are based on inflated projections and the Commission should take a more cautious, measured approach while DTE studies the EV market and while the ramifications of sunsetting tax credits shake out."[533]

This PFD agrees with the Company and MEIU that while there may be a slight downturn in new EV purchases in the test year, DTE's EV forecast remains reasonable, noting that it does not appear that any party addressed EV sales in the secondary market, which are not affected by tax credits, and that may also contribute to additional EV purchases requiring UMR funding. Accordingly, this PFD finds that the Attorney General's adjustment to UMR capital expenditures should be rejected.

c. Projected Meters

Mr. Hill testified that expenditures in the Electric System Equipment subcategory are to maintain an inventory of critical spare equipment, such as transformers, regulators, and meters, to support emergent replacements and planned projects, allowing them to proceed expeditiously.[534] The Company's forecast includes Projected Meters

[532] Attorney General reply, 66.
[533] Id.
[534] 4 Tr 2792-2793.

expenditures of $16,735,000 for 2025 and $17,254,000 for 2026 including a CDA adjustment.[535]

On behalf of Staff, Mr. Hansen recommended that $6,301,229 for the 12 months ending December 31, 2025, and $6,542,690 for the test year, be disallowed for Projected Meters.[536] Staff noted that DTE purchased 115,661 meters in 2024, while the average number of meters purchased in the prior three years was 46,000; the Company informed Staff that the increase in purchases was due to increased, 12 to 15 month, lead times, as well as an abnormally high meter failure rate in 2023.[537]

According to Mr. Hansen, Staff reasoned that this leaves DTE with a 70,000 meter surplus to be delivered sometime in 2025 or 2026, but that 2025 and 2026 proposed meter purchasing was based only on the 2021 to 2023 average investments plus inflation, leaving the surplus meter inventory untouched.[538] Staff recommended the removal of the 70,000 meter surplus from 2025 and 2026 projected spending, subtracting the surplus meters from the average number of meters purchased per year from 2021 through 2023, and then multiplying the calculated number of meters to be purchased by the 2024 average cost per meter.[539] Mr. Hansen indicated that Staff then added in labor and other costs from 2024, and added inflation, to obtain a total recommended recovery of $37,880,082, or total disallowance of $12,843,918.[540] Staff's calculation, set forth on Exhibit S-22.1, calculates disallowance of $6,301,228 for 2025 and $6,542,690 for 2026.

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[535] Exhibit A-12, Schedule B5.4.
[536] 5 Tr 5169.
[537] 5 Tr 5169.
[538] 5 Tr 5169-5170, 5180.
[539] 5 Tr 5170-5171, citing Exhibit S-22.1.
[540] 5 Tr 5170-5171, citing Exhibits S-22.1 and S-4, Schedule D-3a.

Mr. Coppola came to the opposite conclusion, taking the $26,551,000 of capital expenditures for 2024, resulting in $19,179,000 average expenditures from 2022 through 2024, and adjusting this average for inflation.[541] From this, Mr. Coppola forecasted meter purchase capital expenditures of $19,716,000 for 2025 and $20,189,000 for 2026. These are increases of $2,981,000 for 2025 and $2,935,000 for 2026 over DTE's projections; Mr. Coppola recommended they be added to DTE's forecasted capital expenditures.[542]

In his rebuttal testimony Mr. Hill noted Staff's recommendations, but contended DTE installed 36,085 more meters in 2021 through 2023 than it purchased, and the 70,000 meters purchased in 2024 were "necessary to maintain an adequate inventory to meet customer needs and balance its meter inventory."[543] As a result, Mr. Hill urged rejection of Staff's $12,843,918 recommended reduction, contending that the additional purchase made in 2024 to maintain inventory "should not be the determinant for future meter needs."[544] He did not address Mr. Coppola's suggested increase.

The Attorney General's brief repeats Mr. Coppola's recommended increases without additional explanation.[545] Conversely, Staff goes into greater detail in support of reduced spending, noting that DTE purchased 115,661 meters in 2024, with 70,000 of those meters comprising a surplus, that will be delivered throughout 2025 and 2026. As a result, Staff contends that DTE should be expected to purchase fewer meters in those years.[546]

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[541] 5 Tr 3447.
[542] 5 Tr 3447.
[543] 4 Tr 2827-2828.
[544] 4 Tr 2829.
[545] Attorney General brief, 35-36.
[546] Staff brief, 20.

Staff posits that although Mr. Hill testified that the surplus meter purchase was necessary to maintain inventory, in light of an increased number of failed meter replacements in 2023, Staff maintains that DTE did not provide information about historic or current meter inventory beyond providing a table showing installation of 36,000 more meters than DTE purchased between 2021 and 2023. Furthermore, DTE stated that projected meter capital investments for 2025 and 2026 are based on 3-year historical average investments for 2021 through 2023 plus inflation.[547] According to Staff, this means that DTE's projections do not take current meter inventories, surplus meter deliveries, or meter failure trends, into account.[548]

Staff maintains that the large surplus purchase should still factor into the projected purchasing beyond the 3-year historic average, and Staff continues to recommend acceptance of Mr. Hansen's $6,301,228 disallowance for 2025, and $6,642,690 for 2026.[549] However, Staff notes that Ms. Durfee's recommended inflation adjustment overlaps; if that adjustment is adopted by the Commission, Mr. Hansen's proposed reduction would be $5,465,228 for 2025, and $5,680,690 for 2026.[550]

DTE reiterates that the 2024 purchase was a one-time additional purchase to maintain its meter inventory that "should not be the determinant for future meter needs," and urges the Commission to reject Ms. Hill's proposed $12,843,918 reduction.[551] In its reply brief, the Company generally asserts that Base Capital investments, including

[547] Staff brief, 20.
[548] Staff brief, 20-21.
[549] Staff brief, 21.
[550] Staff brief, 21.
[551] DTE brief, 87-88.

spending on projected meters, is appropriate.[552] DTE also rejects the Attorney General's recommended addition to projected meter expenditures, somewhat inexplicably asserting that Mr. Coppola's proposed increase is based on his mistaken rejection of the 2021 to 2023 average and the use of CDA.[553]

The Attorney General's reply brief generally speaks of the rejection of CDA and use of 2020 to 2024 for historical averaging in relation to base capital, but it does not speak to projected meters specifically.[554] Similarly, Staff relies on its earlier filings in its own reply brief.[555]

This PFD adopts Staff's proposed adjustments for 2025, and 2026, which, after removal of CDA result in a disallowance of $5.345 million in 2025 and $5.474 million in 2026. As Staff points out, without knowing more about the actual stock of meters that the Company has on hand, there is no way of being able to discern whether the meter purchases are reasonable and prudent, and nothing precludes DTE from properly supporting an increased meter purchase in a future rate case. Without better information about existing inventory, DTE's declarations of necessity are not enough to establish the accuracy, reasonableness, or prudence of their purchasing forecasts.

F. Distribution Strategic Capital Programs

1. Overview

Mr. Chiu provided a detailed overview of DTE's distribution system and planned investments to improve reliability, resilience, and safety, with a goal of reducing outages

[552] DTE reply, 62-63.
[553] DTE reply, 65.
[554] Attorney General reply, 29-31.
[555] Staff reply, 1.

by 30% and decreasing outage time by half in 2029.[556] According to him: "We know from our recent reliability performance that when we invest, it works."[557]

Mr. Chiu explained that DTE's strategic investments align with Commission's objectives as set forth in the Service Quality and Reliability Standards proceeding, and it comports with the recommendations of the Liberty Audit, "[which] reaffirmed the need for reliability improvements and largely supports the Company's strategy for how to improve distribution operations and power delivery service for customers."[558]

Mr. Chiu stated that DTE invested $1.6 billion in the 2023 historical period, and it is requesting $3.2 billion of distribution strategic capital investments for the 24-month bridge period and $1.9 billion of capital investments for the projected test year, to support the "four essential pillars" (tree-trimming, Infrastructure Resilience and Hardening (including pole-top maintenance and modernization (PTMM), small wires replacement, substation risk projects and 4.8 kV hardening in Detroit), Infrastructure Redesign and Modernization (which includes 4.8 kV conversions, City of Detroit (CODI) investments, Ann Arbor system improvements, and rebuilding and relocating portions of the subtransmission system) and Technology and Automation (including smart grid technology such as sensors, and reclosers).[559]

For specific strategic capital programs, DTE requests $1.152 billion for Infrastructure Resilience and Hardening, $382 million for Infrastructure Redesign and

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[556] 3 Tr 1088-1089.
[557] 3 Tr 1089.
[558] Id.
[559] 3 Tr 1089-1090; Figure 1, 4 Tr 1092.

Modernization, and $498.34 million for Technology and Automation, as shown in Exhibit A-12, Schedule B5.4.

Mr. Chiu described DTE's grid, noting that "Michigan – and the City of Detroit, in particular – has one of the oldest electric grids in the country, and that system is showing its age."[560] Among other things, Mr. Chiu highlighted the fact that 45% of the Company's distribution infrastructure is 4.8 kV installed between 1930 and 1965, which brings both operational and safety challenges, but noting that:

> A combination of the reliability capital improvements in the grid and less extreme weather resulted in a nearly 70% decrease in outage duration times between 2023 and 2024. Looking back further in recent history, electric outages decreased by 14% and the amount of time customers were without power decreased by 38% in 2024 compared to the five-year average (2019 to 2023). This is further validation that when the Company makes these investments, as we have been in recent years, reliability improvements become a reality[.][561]

Several intervenors took issue with many of the Company's strategic distribution investments, as discussed generally below.

While Staff supports many of the Company's initiatives, especially the PTMM and small wire replacement programs, Staff nevertheless raised concerns about the feasibility of significantly increased spending for certain programs or projects, compared to historical spending, given the limited progress in execution to date and past over projections. In addition, Staff questions the accelerated pace of spending in the recloser program, in light of findings from the Liberty Audit.

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[560] 3 Tr 1096.
[561] 3 Tr 1097.

Although focusing primarily on base capital expenditures and CDA, the Attorney General also takes issue with certain proposed substation risk projects and the Company's mobile fleet program maintaining that the programs and costs are insufficiently supported.

MNSC discusses reliability improvements from past distribution capital investments compared to O&M spending for tree trimming and other maintenance activities, as well as shortcomings of the analytical models used to support DTE's proposed distribution spending in the bridge and test periods. MNSC also raises issues concerning the Company's justifications for PTMM spend, including inspection cycles and capitalization of vegetation management and minor replacements; Subtransmission Redesign and Rebuild (SRR) investments; certain System Loading and Circuit Conversion projects; Distribution Automation; and Grid Automation Telecommunications.

ABATE discusses at length the drawbacks of DTE's BCAs used to support several distribution program investments, along with making recommendations for adjustments to the Distribution Automation and PTMM programs, consistent with the Liberty Audit. In general, given the Company's poor reliability metrics and consistent underspending on its distribution programs, ABATE witness York also recommended that the Commission disallow recovery of all Strategic Distribution projects that are not expected to be in service in the bridge or period or test year, resulting in a disallowance of $829.311 million.[562]

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[562] 4 Tr 3263-3264. As Mr. Chiu pointed out, because the projects are not expected to be in service in the bridge or test periods, their removal has no impact on the revenue requirement. 3 Tr 1172. Staff similarly points out that the Commission has rejected adjustments made based on in-service dates. Staff brief, 15, citing 5 Tr 5294-5295. This PFD agrees that ABATE's recommended disallowance on the basis that certain projects will not be useful in the bridge or test periods should be rejected.

The CEO raise concerns about the potential for escalating costs in the PTMM and the lack of an adequate BCA for Distribution Automation. The CEO also supports securitization of distribution "surge" spending as proposed by MNSC.

Ann Arbor recommends that Distribution Automation investments in reclosers, beyond those required for safety, should be disallowed. In addition, Ann Arbor recommends that increased costs for poles should be disallowed, arguing that some portion of these costs could have been avoided had the Company replaced the equipment earlier under a standard inspection cycle.

In addition to the overview provided by Mr. Chiu, several other Company witnesses addressed various aspects of the Company's planned distribution system strategic investments including Mr. Kryscynski (distribution O&M, and DTE's Global Prioritization Model (GPM) and Reliability Model (RM)); Mr. Robinson (Infrastructure Resilience and Hardening); Mr. Stowe (Infrastructure Redesign and Modernization); Mr. Rademacher (Technology and Automation); and Mr. De Stigter (BCAs for PTMM, Strategic Undergrounding, Distribution Automation, and Grid Automation Telecommunications).

Additional background and specific issues raised with respect to DTE's proposed investments are addressed below.[563] The PFD further notes that DTE proposes that certain costs be collected through the IRM. Issues regarding DTE's IRM proposals are addressed elsewhere in this PFD.

2. Modeling

[563] Strategic Undergrounding pilots are addressed in the pilots section of this PFD.

As noted briefly above, DTE presented the results of two models, the GPM, and the RM, the BCAs prepared by 1898 & Co, as well as portions of the Liberty Audit, in support of its proposed investments. General issues related to the GPM, RM and BCA's are addressed below. Specific concerns about these models as applied to particular programs or projects are discussed in the sections on the program or project.

a. Global Prioritization and Reliability Models

Mr. Kryscynski presented the GPM framework and model, contained in Exhibit A-23, Schedules M14 and M14.1, explaining that the Company's distribution team developed the model some years ago to prioritize distribution investments. According to him:

> The ranking is accomplished through a process of an economic evaluation method, the "best-fit, most reasonable cost," to prioritize projects across eight impact dimensions that are aligned to the DTE Electric planning objectives, and develop a total project score based on the weighting of each impact dimension. Each of the eight impact dimensions within the GPM measures a benefit of the project or program. Projects delivering the most value across the eight impact dimensions are prioritized for earlier investment. The model results serve as the initial basis for the Company's investment prioritization and highlight those projects that have the highest relative benefit and/or are most urgent. [564]

As shown in Table 1 at 3 Tr 1200, Mr. Kryscynski showed the GPM impact dimensions (reduced hazards, overload relief, SAIDI, SAIFI, major event risk, capacity relief, O&M avoidance, and capital avoidance) as they intersect with DTE's distribution grid plan (DGP) planning objectives. Mr. Kryscynski further testified that the GPM was discussed in the Liberty Audit in positive terms and that the Commission found that DTE

[564] 3 Tr 1197.

had made progress in terms of transparency in its GPM presented in Case No. U-21534.[565]

Mr. Kryscynski also detailed some modifications to the GPM including removal of the regulatory compliance dimension, changes to the safety dimension, and changing EJ from a dimension to a multiplier.[566] He presented the current list of GPM dimensions and multipliers in Table 2 at 3 Tr 1204, and he presented the list of the top 50 strategic capital programs and projects ranked by the GPM in Table 4 at 3 Tr 1209.

Turning to the Reliability Model (RM), Mr. Kryscynski testified that six investment programs are included in the RM (tree trimming, 4.8kV hardening and conversion, PTMM, customer excellence, and distribution automation), explaining:

> The Reliability Model is an analytical tool that estimates tangible reliability improvements associated with proposed capital investments in a data-driven framework and on a circuit-by-circuit basis. See Exhibit A-23 Schedule M12. The model calculates improvements from investment programs and projects on the basis of industry-standard performance metrics and includes an adjustment for post-investment degradation over time, providing a way to numerically estimate the reliability benefits that the proposed projects will provide. Alongside the GPM and BCA tools, the Reliability Model is an important vehicle for evaluating and ranking capital investments so that the Company is delivering maximum value and impact for customers.[567]

Mr. Kryscynski described the process the Company uses to estimate reliability improvements at a circuit level, including establishing baseline reliability, program effectiveness, degradation, and expected future performance with MEDs and x-MEDs.[568] He further explained that the RM analysis, set forth in Exhibit A-23, Schedule M12, has

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[565] 3 Tr 1198-1199.
[566] 3 Tr 1201-1202.
[567] 3 Tr 1213, 1214.
[568] 3 Tr 1214-1217.

been updated since DTE's last rate case to include a full calendar year, incorporate actual reliability performance in 2023 and 2024, and exclude performance during the year the investment was made.[569]

Mr. Kryscynski presented the projected results (all-weather SAIDI and SAIFI) of distribution operations investments proposed in the instant case in Figure 2 at 3 Tr 1219. He further observed that the RM used in DTE's previous case forecast all-weather SAIDI of 504 minutes (compared to 483 minutes actual), and it projected all-weather SAIFI of 1.30 (compared to 1.25 actual).

MNAG witness Alvarez described the operation of the GPM testifying that the scores resulting from the model, which essentially evaluates benefits, and provides project or program priorities, stating that, "[i]n theory, the higher the score for a project or program, the more beneficial the project or program is to customers."[570] He noted, however, that a higher-scoring project in terms of benefits derived from the GPM, does not necessarily mean that the project is cost-effective. Mr. Alvarez further opined that the extent that DTE completes the list of prioritized projects depends largely on the amount of capital spending the Commission approves.

Mr. Alvarez criticized the GPM for a number of reasons. First, he testified that the scoring results are completely subjective, observing that each of the GPM dimensions is weighted differently by subject matter experts, as are the scores for each dimension for each project or program. According to him, using both subjective weighting of benefits and subjective scoring of projects results in the GPM being "a poor prioritization tool, and

[569] 3 Tr 1216.
[570] 5 Tr 4617.

meaningless as a capital planning tool."[571] He explained that using scores for rating benefits, rather than dollars, it is impossible to compare benefits to costs and determine which projects are most cost-effective.

Second, Mr. Alvarez raised a concern that "[t]he GPM does not distinguish between discrete projects, such as a $4 million project to rebuild subtransmission circuit tie 1568 (ranked #10 of all potential projects DTE could implement) and massive programs, such as Distribution Automation (ranked second, for which DTE proposes to spend $850 million in capital 2026-2029)."[572] As such, Mr. Alvarez suggested that a risk-informed BCA should be added to the GPM, noting that in its order in Case No. U-21534, p. 133, the Commission determined that such an analysis could be useful for SRR projects. He further recommended that this type of approach be used for any discretionary capital project or program.[573] In sum, Mr. Alvarez recommended that the Commission reject the results of the GPM in evaluating capital projects, and that the Commission direct the Company to undertake a risk-based BCA in future rate cases.[574]

Addressing the RM, Mr. Alvarez provided an overview of how the model operates and how DTE uses the RM in supporting its spend plans.[575] Observing that although the operation of the model appears to provide logical projections, Mr. Alvarez testified that "DTE's Reliability Model is an exercise in baseline data manipulation, the application of unvalidated assumptions, and inappropriate extrapolations. These manipulations,

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[571] 5 Tr 4620.
[572] 5 Tr 4620 (internal citations omitted).
[573] 5 Tr 4621-4622.
[574] 5 Tr 4623.
[575] 5 Tr 4623-4624.

assumptions, and extrapolations render the improvements projected by the Reliability 2 Model completely undependable."[576]

Specifically, Mr. Alvarez questioned how DTE established baseline reliability for each circuit, first by removing MED interruptions, a step he described as "a huge red flag and antithetical to the concept of a baseline."[577] In addition, according to him, DTE: (1) separates outages by cause (vegetation versus other causes); (2) separates outages affecting one customer from outages involving multiple customers; and (3) for multiple-customer outages, the actual number of customers out is replaced by the system average of customers interrupted, and the actual outage minutes is also replaced by the Company's average outage minutes. Mr. Alvarez raised concerns with the amount of data "manipulation" undertaken to arrive at a baseline and the purpose for doing so.[578]

Next, Mr. Alvarez again pointed to the extent to which assumptions about reliability improvements for certain programs are established by subject matter experts, rather than analysis using historical data, which is certainly available. And he noted that for the four programs that do rely on historical information, (i.e., 4.8kV hardening; PTMM, and customer excellence) tree trimming is used extensively, making it difficult to determine the extent to which the performance improvement is due to the program rather than vegetation management.[579]

Lastly, Mr. Alvarez opined that DTE failed to validate the RM and that DTE used inappropriate extrapolations (scaling factors) in arriving at projected reliability

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[576] 5 Tr 4624-4625.
[577] 5 Tr 4625.
[578] Id.
[579] 5 Tr 4625-4626.

improvements with MEDs. He further observed that although the Liberty Audit did not provide much detail about the RM, it did find "large uncertainties" associated with projected improvements by program and activity, concluding that "'It will likely take more work and thus even higher costs to achieve the reliability results forecasted [by the RM]'"[580]

In rebuttal, Mr. Kryscynski countered that there were oversights and significant errors in Mr. Alvarez's assessment of the GPM including: (1) he failed to address the findings of the Liberty Audit, which found the GPM "sound" and "consistent with other utility strategic investment good practices that Liberty has experienced";[581] (2) Mr. Alvarez failed to consider that the Commission, in the U-21534 order found no need to direct DTE to make additional changes to its modeling;[582] (3) Mr. Alvarez injected his personal opinion regarding how DTE selects projects and programs for investment, greatly oversimplifying the process for capital planning; and (4) Mr. Alvarez failed to recognize that the Company provided additional modeling and analysis, including BCAs that address significant initiatives.[583]

With respect to the critique of the RM, Mr. Kryscynski summarized Mr. Alvarez's claims, responding that Mr. Alvarez's understanding was inaccurate, incorrect, or oversimplified.[584] Mr. Kryscynski testified that many of the reliability improvements projected in the RM are in fact based on historical data, specifically discussing historical data from the Hilton Road 4.8kV hardening project, which includes information from three

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[580] 5 Tr 4628, quoting Exhibit MNAG-PA-3, Liberty Audit, Part II, p. 67.
[581] 3 Tr 1270, quoting Audit, Part II, pp. 24-25.
[582] 3 Tr 1270 quoting Order, 98.
[583] 3 Tr 1271-1272.
[584] 3 Tr 1278.

years before the project, along with data from other conversions and subject matter expertise.[585]

Mr. Kryscynski also noted that Mr. Alvarez's concerns about SAIDI on 4.8kV circuits compared to 13.2kV circuits, indicating that reliability on the 13.2kV circuits was worse, was based on data from two rate cases ago; it was erroneous, and the analytical approach used by Mr. Alvarez was overly simplistic.

Turning to tree trimming impacts on reliability as addressed in the RM, Mr. Kryscynski reiterated that tree-related and non-tree-related events are accounted for, noting that outage events associated with wind are treated as tree-related.

And regarding Mr. Alvarez's claims regarding the development of the baseline data, Mr. Kryscynski stated that: (1) x-MED performance is used because it is more consistent and better represents system improvement; (2) while the baseline data is "manipulated" it is not done so to drive a specific outcome, noting that, "the Reliability Model is based on extracting insights from close to a million events across thousands of distribution circuits, a level of filtering, sorting and aggregating data is necessary to build a useful model[;]" and (3) concerning the conversion of actual number of customers interrupted and minutes interrupted to system averages, Mr. Kryscynski explained that DTE's approach is intended to simplify a complex modeling process opining that "[f]uture performance is more likely to be closer to the average number of events and the average size of an outage on a system of the same voltage type."[586] Lastly, Mr. Kryscynski addressed the specifics of how the RM scales up x-MED data to all-weather performance,

[585] 3 Tr 1280.
[586] 3 Tr 1285.

and he reiterated that the RM accurately projected 2024 SAIDI and SAIFI, thus validating the model's performance.[587]

In briefing, DTE relies on Mr. Kryscynski's testimony, emphasizing that the information used in the GPM is either objective or based on subject matter expertise, pointing specifically to SAIDI, SAIFI, wire down, equipment ratings and historical costs per event, all of which are objectively measured.[588] Turning to the RM, DTE reiterates that MNAG disregards all of the data that has been presented in this case that supports reliability improvements, as shown in Exhibit A-23, Schedule M12.[589]

MNSC argues that DTE's claims about the Commission's "approval" of the GPM in the U-21534 order was overstated, quoting the Commission's observation that the Company should include more actual performance data, rather than relying on subject matter experts, something that DTE failed to do in its presentation in this case. Moreover, MNSC notes that the Company failed to incorporate several recommendations contained in the Liberty Audit related to specific programs.

MNSC contends that DTE's claim that the GPM relies largely on objective data is similarly overstated highlighting: "one key "objective" factor is '[p]rojected improvement' – a score based on estimates of safety (wire down) and reliability (SAIFI, SAIDI) reductions from a program/project. These estimated projections may be "objective" calculations (e.g., 23% reduction in wiredowns), but they are also entirely and inherently subjective."[590]

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[587] 3 Tr 1286-1287.
[588] DTE brief, 44-45.
[589] DTE brief, 45-46.
[590] MNSC brief, 26.

Next, MNSC maintains that DTE does not validate the costs and benefits in the GPM, citing a discovery response contained in MEC-41, pp. 1-2, wherein the Company stated that while program costs are updated, benefits are "assumed," meaning "if a project planned to address a constraint, it is assumed it achieved it."[591]

Turning to the RM, MNSC reiterates Mr. Alvarez's testimony that the model is biased in favor of capital, rather than O&M spending, again pointing out that the baseline data is manipulated and that most of the benefits are estimated by subject matter experts rather than based on historical information on outages before and after treatment. [592]

Responding to Mr. Kryscynski's rebuttal, MNSC maintains that simply because the RM reasonably accurately predicted system-wide SAIDI and SAIFI reductions, this does not mean that the RM supports specific spend plans for programs or projects. According to MNSC, "[tree] trimming may have resulted in more benefits in 2024 than the RM projected and PTMM may have resulted in less benefits than the RM projected, so the RM's projected aggregated performance SAIDI may appear relatively accurate, though it projected benefits of both programs inaccurately."[593] MNSC thus reasserts that DTE should be required to provide actual comparisons of before and after treatment results, "controlled for trimming and other potentially contributing factors, to support program/project spending plans."[594]

Less than one year ago, the Commission addressed the GPM and RM in the order in Case No. U-21534. While finding some improvements in both models, especially in

[591] Id. at 27.
[592] MNSC brief, 29.
[593] MNSC brief, 30.
[594] Id.

terms of transparency in the GPM, the Commission nevertheless reiterated its findings from the Company's previous rate case, stating:

> [T]he Commission agrees with the ALJ that given the evergrowing substantial volume of issues raised in general rate cases, it is not possible to address every party's concerns regarding the methodology DTE Electric developed to prioritize its capital expenditures for distribution projects. The Commission's role in this rate case is to take the DGP and underlying GPM under consideration as evidence supporting the company's cost recovery requests in this case. That consideration includes weighing and evaluating the credibility of that evidence—the DGP and GPM—to determine whether it supports the spending proposed by the company and whether it is reasonable and prudent to pass those costs on to ratepayers.[595]

This PFD agrees that there is simply not enough time to fully examine and address the strengths and weaknesses of the GPM and RM, given the strict time constraints for completing a rate case. Thus, this PFD adopts the guidance provided by the Commission in the U-21534 order and considers the GPM and RM as pieces of evidence that may provide some support for specific program or project spending.

b. Benefit Cost Analyses

Mr. De Stigter presented the BCAs performed by 1898 & Co to support the PTMM, Distribution Automation, Strategic Undergrounding, and Grid Automation Telecommunications programs.[596] The results of the various BCAs are presented in Exhibit A-28. Schedule R3.

Mr. De Stigter explained that the objectives of the BCAs were threefold: (1) quantify improvements expected for each investment activity studied, in a way that is customer-focused; (2) demonstrate (and monetize) expected improvements in the

[595] January 23, 2025 order in Case No. U-21534, p. 97.
[596] Strategic Undergrounding is addressed below under Pilot Programs.

frequency and duration of outages for certain programs; and (3) prioritize Company investments to ensure that the highest benefit per dollar projects or programs are implemented.[597]

Mr. De Stigter testified that using a proprietary model developed by 1898 & Co, he used Company data and various technical algorithms "to calculate the resilience, reliability, and risk mitigation benefit of investments by identifying the expected range of reduced duration and frequency of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced outage restoration costs."[598]

Mr. Alvarez raised concerns that the BCA modeling was not transparent or objective, tending to understate costs and overstate customer benefits, noting that by using proprietary software, intervenors were unable to independently evaluate the model or its results.[599]

Turning to modeling inputs, Mr. Alvarez pointed out that customers incur more than just the capital costs of a project, with additional costs including interest on debt, ROE, income, sales, and property taxes. He estimated that capital investments cost customers about 30% more in total (NPV) than O&M expenses, and that the model underestimates actual capital costs by that amount.[600]

In terms of customer benefits, noting that the model uses the DOE's Interruption Cost Estimator (ICE) tool to convert reliability benefits into dollar values, Mr. Alvarez testified that there are general concerns that the ICE tool tends to overstate the benefit of

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[597] 4 Tr 1840.
[598] Id.
[599] 5 Tr 4631, 4637.
[600] 5 Tr 4633.

reliability improvements. Moreover, according to Mr. Alvarez, "the BCA model inflates these dollar values further by placing a higher value on service interruptions avoided by 'critical customers.' I have never observed any utility inflating reliability improvement value in such a manner, nor does the Department of Energy's online ICE tool provide for this."[601]

Specifically, Mr. Alvarez explained that 4.2% of DTE's C&I customers, including those with back up generation, are deemed "critical" in the BCA. As such, a three-times higher dollar value is assigned to avoided interruptions of these customers, compared to other C&I customers.[602] According to him, the number and type of customers considered critical in the BCAs requires much more scrutiny, because this approach appears to result in significantly inflated benefits.

MNAG witness Stephens raised similar concerns about the BCA in the context of specific program areas.

ABATE witness Fitzhenry similarly criticized the BCA analytical methods, first noting that the BCA approach is an economic, rather than a financial, model. Like Mr. Alvarez, Mr. Fitzhenry observed that the costs used for the projects evaluated do not include taxes, ROE, interest expense, or stranded asset costs that will be collected over the life of the investment, meaning that actual costs are higher than those included in the BCAs. But benefits are assumed in each future year and are discounted to the present.[603] Mr. Fitzhenry emphasized that if all costs were included, as would be the case with a financial model that evaluates spending from customer's perspective, costs would be

[601] 5 Tr 4633.
[602] 5 Tr 4633-4634.
[603] 4 Tr 3357-3358.

much higher and projects or programs would be less cost-effective than the Company has demonstrated.[604]

Next, Mr. Fitzhenry discussed internal information provided by DTE, including outage causes, durations, number of customers interrupted, and CMI for 2019-2023. that was used to identify outages that can be mitigated by investments. Mr. Fitzhenry testified that because investment data was not updated:

> This means that outage data for a particular circuit is based on the five-year historical average outage data for that circuit and may not reflect recent investment made at the circuit to mitigate future outages. For example, consider a circuit that experienced outages in 2019 and 2020, but, in 2021, an investment was made to mitigate future outages or improve reliability. As a result of the investment, the circuit experienced no outages in 2021 through 2023. The outage data would reflect the average circuit performance over the five years, inclusive of the years with poor reliability performance (2019 and 2020) and improved reliability performance (2021-2023). As a result, the benefits assumed by the Outage Mitigation Risk & Resilience model would be overstated because the model is not biased to consider recent performance or reliability investments that were made during the OMS data collection period (2019-2023).[605]

In Table CTF-1, at 4 Tr 3361, Mr. Fitzhenry highlighted the significant improvement in all-weather SAIDI in 2024, 483 minutes, compared to the five-year historical average of 774.3 minutes. According to him, assuming that the 2024 data is more reflective of current system performance than the previous five years of data used in the BCAs, "the OMS data would be overstating the likelihood of customer outages by approximately 60%," thus inflating the benefits of future investments.

Turning to the monetization of benefits through the ICE tool, Mr. Fitzhenry pointed out that: (1) the ICE calculator used by 1898 & Co has been replaced by the ICE

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[604] 4 Tr 3358-3359.
[605] 4 Tr 3360.

Calculator 2.0, which allows for additional inputs and a more detailed assessment of outage costs by region; (2) DTE has not participated in the DOE survey for determining interruption costs, "so the cost are not reflective of DTE customers' willingness-to-pay amounts for avoided outages;" and (3) the introduction of "critical customers," and reliability impacts on such customers, is speculative and not a part of the ICE calculator.[606]

In summary, Mr. Fitzhenry recommended that the BCA be disregarded for purposes of making investment decisions, because true costs to ratepayers are misrepresented; given the reliance on historical outage information (not updated for 2024 performance), the BCA overstates the benefits of future investments, and the ICE Calculator does not reflect the willingness-to-pay for avoided outages specific to DTE's customers.[607]

CEO witness Volkman also testified that the BCAs presented here do not include the full revenue requirement and they underestimate future costs, specifically noting the strong possibility of material and labor cost increases in the PTMM and distribution automation programs.[608] He recommended that a sensitivity analysis incorporating cost increases for certain equipment (poles, transformers, reclosers, overhead conductors) be performed to assess the impacts on the BCAs. Ann Arbor witness Stultz raises concerns that the BCAs do not reflect the results of the recent tree-trimming surge.

In rebuttal, Mr. De Stigter countered that the BCA models are based on objective data and are in no way biased toward capital spending. He added that using a revenue requirements-based approach to the modeling, as suggested by Mr. Fitzhenry and Mr.

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[606] 4 Tr 3362.
[607] 4 Tr 3362-3363.
[608] 4 Tr 3656.

Alvarez is unnecessary because both costs and benefits would be impacted equally, and if not, the differences in results would be minor; the models already account for the costs intervening witnesses claim should be included, and the use of a revenue requirements-based approach is not an "established standard."[609] Mr. De Stigter also elaborated on the flaws contained in the revenue requirements analyses performed by Mr. Alvarez and Mr. Fitzhenry, both generally and as related to specific program areas.[610]

Mr. De Stigter also defended the designation of "critical customers" in his analyses, describing these customers as having "high priority status during power restoration after an outage," such as hospitals, senior centers, and water treatment plants.[611] He further explained that the multiplier for critical customers does have a basis in the ICE calculator, presenting Table 6 at 4 Tr 1894, to demonstrate how the value for critical customers was derived, further observing that even if critical customers are not more heavily weighted, the results of the BCAs change very little.[612]

Responding to Mr. Fitzhenry's claim that benefits are overstated in the BCAs because significant reliability improvements in 2024 were not included in the modeling, Mr. De Stigter disagreed, pointing out that 2024 reliability data was not available when the analyses were performed. He further described Mr. Fitzhenry's assumptions as "extremely flawed" surmising that the improvement in reliability was likely due to less storm activity, and not system improvements.[613]

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[609] 4 Tr 1876; 1872-1881.
[610] 4 Tr 1882-1891.
[611] 4 Tr 1893.
[612] 4 Tr 1894-1895.
[613] 4 Tr 1899, 1900-1902.

Next, Mr. De Stigter acknowledged that Mr. Volkman's concerns regarding increased (above base inflation) material and labor costs are valid, and he discussed the results of the sensitivity analyses he performed, noting that even assuming significant material and labor cost increases, the impacts on the BCAs for most projects are minimal.[614]

The parties' briefs generally rely on their witnesses' testimony. In response to Mr. De Stigter's rebuttal, MNSC argues that it is not surprising that updating the costs in the BCAs resulted in few projects being reclassified as cost-ineffective, "considering the model estimates enormous benefits relative to program costs."[615] MNSC further clarifies that the ICE calculator significantly overstates the benefit of residential reliability in particular, because residential customers typically pay approximately 50% of costs for improvements while only garnering 9% of reliability value.[616] Thus, from the standpoint of residential customers, some of DTE's proposed initiatives "are highly cost-ineffective for [these] customers."[617]

ABATE's brief relies on Mr. Fitzhenry's testimony, emphasizing that in dismissing the impact of costs like ROE, taxes, and stranded costs in the BCAs, DTE "glosses over the significant deficiencies in its analysis by simply claiming the benefits of excluded costs probably cancel out the costs anyway. Throwing up one's hands and simply excluding a quantifiable cost because diffuse societal benefits are presumed to be equal but are

[614] 4 Tr 1905-1908.
[615] MNSC brief, 34-35.
[616] Id. at 35.
[617] MNSC brief, 35.

challenging to estimate is not a proper basis for requesting millions of dollars in cost recovery."[618]

This PFD generally agrees with the intervenors that the BCAs presented by DTE for the programs discussed below, are insufficient to support the hundreds of millions of dollars in ratepayer funding that the Company proposes here. First and foremost, the introduction of a proprietary model in a regulatory proceeding such as this one greatly disadvantages the other parties, who are not permitted to fully examine how the model operates or determine whether there were specific errors in inputs or assumptions, which in turn might lead to erroneous output.

Second, this PFD agrees with ABATE, MNSC, and the CEO, that the BCAs, as presented by Mr. De Stigter, do appear to significantly underestimate costs, by excluding items like ROE, taxes, debt financing, and potential above-inflation material and labor increases, while at the same time overestimating future benefits through the introduction of critical customers in the ICE calculator and the failure to update reliability (SAIDI) for 2024. Accordingly, this PFD finds that the Company's BCAs should be afforded minimal weight in evaluating DTE's proposed investments in distribution strategic capital programs discussed below.

3. Pole Top Maintenance and Modernization

The PTMM is part of DTE's Resilience and Hardening pillar and was one of the more controversial matters in this proceeding. As described by Mr. Robinson, the PTMM program:

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[618] ABATE brief, 14.

> . . . is designed to inspect and maintain overhead distribution equipment to enhance system reliability and resilience against weather, storms, and tree-related events. It involves inspecting all wood poles and pole-top equipment on distribution and subtransmission overhead circuits, and replacing any that fail inspection with stronger, potentially higher-class poles and upgraded pole-top materials. These new materials, such as fiberglass crossarms and polymer insulators, offer significantly greater mechanical strength and durability, resulting in fewer equipment failures and customer outages.[619]

Mr. Robinson explained that about 70% of DTE's electric grid is overhead, and approximately 25% of outages are caused by overhead equipment failures.[620] Mr. Robinson discussed the age of the Company's poles, noting that almost 50% of the utility's one million poles are over 50 years old, at or beyond their useful lives.[621]

Mr. Robinson discussed the development of the Company's PTMM, largely based on peer utility benchmarking, which resulted in a recommendation that the program should be designed to inspect and repair/replace pole tops on a five-year cycle, and inspect poles on a 10-year cycle.[622] Mr. Robinson noted that the Commission addressed the 5- and 10-year cycles in DTE's last rate case, approving cost recovery with a caveat that the Liberty Audit might affect the analysis of the program. In turn, the Audit recommended a four to five year inspection cycle for pole tops, with an adjustment in near term spending to recognize a likely high rate of replacements in the first inspection cycle.[623]

After providing a detailed review of pole and pole top inspection activities, including the number of miles that need to be inspected annually to achieve on-cycle inspection by

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[619] 4 Tr 1933.
[620] Id.
[621] 4 Tr 1934-1935.
[622] 4 Tr 1937-1938.
[623] 4 Tr 1938-1940

2029, Mr. Robinson testified that the PTMM is funded for 2025 at $121 million. In this case, DTE is requesting this amount be increased to $200 million in the 2026 test year.[624]

Mr. Robinson discusses the results of the BCA for PTMM, noting a benefit cost ratio (BCR) of 2.76 for the entire distribution system, not including the benefits associated with the reduction in safety risks.[625] Company witness Willis testified that the $200 million proposed spending should be included in the IRM.

While Staff supported DTE's PTMM proposal as presented, other parties took issue with certain aspects of the program, including proposed expenditures, inspection cycles, and cost capitalization. These issues are addressed below.

a. Expenditures

As noted above, Staff supports DTE's recommended increase in funding for the PTMM program, as well as its's request to include PTMM cost recovery in the IRM. Mr. Boutet testified that "Staff would like to stress the importance of this program and its relation to the results of the Liberty audit in Case No. U-21305[,] a major recommendation of which was to achieve a four- to five-year inspection cycle, adjusting spending to account for likely higher costs in the first cycle.[626] Mr. Boutet explained that based on its review, Staff found the pole and pole top inspection and repair cycles conform to both the Liberty Audit results and industry standards.[627]

Mr. Fitzhenry testified that the projected cost for the PTMM program is approximately $1.44 billion from 2025 through 2029, noting that the Liberty Audit, Part II,

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[624] 4 Tr 1942-1944.
[625] 4 Tr 1945-1946.
[626] 5 Tr 5147, quoting Liberty Audit pp.41-43.
[627] 5 Tr 5148.

page 41, indicates “a lack of reliable data and analysis from DTE to accurately estimate the costs of moving to a shorter, more effective cycle . . . suggest[ing] that the initial costs of a shortened cycle would be significantly higher than DTE's current projections because of the large number of deferred repairs that would be discovered.”[628]

Given this uncertainty, Mr. Fitzhenry recommended that PTMM investments be held to 2025 levels, adjusted for inflation, until DTE can improve efficiency or provide more data on program costs.[629] As noted above, CEO witness Volkman also raised a concern that DTE can achieve the 5-year and 10-year inspection cycles with the funding DTE proposes.

In rebuttal, Mr. Robinson disagreed with Mr. Fitzhenry, testifying that the BCA and PTMM ramp-up plan were developed after the Liberty Audit was complete, and in response to the recommendations therein. Mr. Robinson reiterated that based on the Company’s PTMM spending plan, the Company anticipates achieving the cycles recommended by the Audit, at which point, costs are expected to decrease considerably.[630]

Mr. Boutet also countered Mr. Fitzhenry’s recommendation, noting that the Liberty Audit found that DTE’s 2023 spending on PTMM was not sufficient to sustain even a 20-year cycle, let alone the cycles recommended in the Audit.[631]

The parties’ briefs reiterate the direct and rebuttal testimony of their respective witnesses.

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[628] 4 Tr 3366.
[629] 4 Tr 3367.
[630] 4 Tr 2041.
[631] 5 Tr 5154.

This PFD agrees with DTE and Staff, that the proposed PTMM program investment amount should be increased to $200 million in the test year and included in the IRM.[632] Leaving aside the results of the BCA, the PFD nevertheless finds persuasive the Company's benchmarking, which indicates that a five-year cycle for pole top inspections and a 10-year cycle for pole inspections are standard in the industry. And while it is true that the Liberty Audit expressed some uncertainty about near-term costs, it nevertheless endorsed the need for the program, and no party disputes that PTMM costs are very likely to decrease once the first inspection cycle is completed. Finally, As DTE and Staff point out, DTE's current inspection cycle and funding levels are not sufficient to even achieve a 20-year cycle; thus, ABATE's recommendation to keep funding at 2025 levels adjusted for inflation would result in the Company falling even further behind.

b. Inspection Cycles

As discussed above, DTE, supported by Staff, recommends moving the inspection cycle to 5-years for pole tops and 10-years for poles.

MNAG witness Stephens opined that "[s]ignificant reliability improvements are not possible from increases in PTMM inspection frequency and construction standards," and he cited the Liberty Audit's finding of a 5% defect rate as evidence that the Company's poles and poletops "are not in unreasonably poor condition."[633] Mr. Stephens testified that the Company was nevertheless proposing "massive increases" in PTMM spending, including $1.12 billion in spending recoverable through the IRM.[634] He also observed that

[632] This amount is offset slightly as discussed below.
[633] 5 Tr 4520.
[634] 5 Tr 4520-4521.

for outages caused by equipment failures, those caused by poles and pole top equipment are rare.[635]

Based on his assessment, Mr. Stephens recommended that the Company's PTMM inspection frequency be relaxed from a five-year cycle to a 10-year cycle, testifying that DTE failed to support its plan to shift to a five-year inspection cycle with an adequate BCA.[636]

Mr. Robinson responded that MNAG's recommendation for a longer inspection cycle contradicts a specific finding from the Liberty Audit that DTE should implement a four- to five-year inspection cycle for pole tops, and he also pointed to the benchmarking that the Company did to support its proposal. Lastly, Mr. Robinson pointed to the orders in Case Nos. U-21534 and U-21305 where the Commission agreed with a shorter inspection cycle for PTMM and expressly agreed with that finding in the Liberty Audit.[637] In their initial briefs, DTE and Staff rely on the direct and rebuttal testimony of witnesses Robinson and Boutet.

In briefing, MNSC points out the over half the annual PTMM spending in 2025 and 2026 is for pole replacement, whereas the inspection component comprises only 1% of total program costs, despite the Audit's recommended first priority to "establish visual control over the system."[638]

MNSC argues that the Liberty Audit also highlighted the fact that given the current state of DTE's system, and other competing needs, the Company needs to find a way to

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[635] 5 Tr 4532.
[636] 5 Tr 4521-4523, 4532.
[637] 4 Tr 2036-2038.
[638] MNSC brief, 38, quoting Liberty Audit Part II, p. 48.

spread first inspection cycle costs over a longer period. Quoting from the Audit, MNSC expresses agreement that DTE still needs to develop appropriate standards and criteria to lower the costs of the first inspection cycle.[639] According to MNSC, not only has DTE failed to establish new criteria for PTMM, but the Company intends to continue its current program, which involves extensive replacement of old but undamaged equipment at an accelerated pace.[640] In a similar manner, MNSC questions the Company's plans for pole replacement, again observing that many of the poles DTE assumes will require replacement are based on a small sample of poles inspected as part of the Liberty Audit.[641] Moreover, of the 120 pole sample, "Liberty identified 10 poles with conditions "needing attention," which does not correlate to issues that require pole replacement, as DTEE concedes."[642]

While this PFD agrees that moving to a 5-year inspection cycle for pole tops is essentially settled, in light of the Commission's findings on this issue in Case Nos. U-21534 and U-21305, this PFD also agrees that if DTE does not take a more measured approach to repairs, costs for the PTMM could balloon while purported reliability improvements might lag.

As MNSC point out, DTE is designating equipment that is old or outmoded as defective, even though it is not damaged. Replacing this functioning, albeit antiquated, equipment serves only to increase costs, without improving reliability. As such, this PFD agrees with MNSC that DTE should reevaluate its criteria for determining what

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[639] MNSC brief, 41.
[640] Id. at 42.
[641] MNSC brief, 44.
[642] MNSC brief, 44, citing Exhibit MEC-15, p. 1.

equipment, including poles, needs immediate replacement and what equipment can be replaced in the future.

c. Pole Replacement Costs

Ann Arbor recommends that $2.622 million in pole material costs be disallowed "as a conservative approximation of ratepayer savings that would have resulted from DTE following industry standard inspection and maintenance practices for overhead circuits."[643] Ann Arbor witness Stultz testified that she reviewed the Liberty Audit, which, among other things found that DTE has not followed the common industry practice of conducting visual inspections on a four to five year basis. Instead, the Company has been inspecting and testing poles on a cycle that averages 12-13 years.[644]

Dr. Stultz further reported that the Audit found that DTE inspected 229,450 poles in a five-year period and that the Company replaced approximately 6% of the poles inspected. She presented a table at 4 Tr 3732, which shows, for 2019-2023, the number of pole inspections, number of poles replaced based on those inspections, and number of poles replaced for other reasons. Dr. Stultz posited that if DTE had been on a five-year inspection cycle, it would have inspected all of its poles in the 2019-2023 period and it would have replaced 65,054 poles in that period (based on the inspection replacement percentage).[645]

Using 2019 for comparison, Dr. Stultz calculated that had DTE been on a five-year inspection cycle, it would have replaced approximately 14,456 poles that year. Instead, the Company only replaced 2,822 poles due to inspections, a deficit of approximately

[643] Ann Arbor brief, 11.
[644] 4 Tr 3731.
[645] 4 Tr 3732.

9,269 poles, including poles that would have been replaced for other reasons. Dr. Stultz testified that DTE is projecting to replace 18,090 poles as part of the PTMM and 4.8kV hardening program, further noting that pole material costs have increased by 131% or $145 per pole since 2019.[646] According to her, if, in 2019, DTE had replaced the 18,090 poles it requests funds for in this case the Company could have saved over $2.6 million in materials costs alone. Dr. Stultz explained her recommended disallowance of this amount:

> As explained above, . . . [$2,621,701] is the amount DTE would have saved (in material costs alone) had it replaced the 18,090 poles for which it is requesting funding in the test year at 2019 costs. This recommended disallowance prevents some of the increased costs due to DTE's failure to replace poles on a more prudent schedule from being passed on to ratepayers. Even this disallowance would still leave ratepayers shouldering additional costs that were avoidable had DTE performed normal maintenance, notably including labor costs. Essentially, this allows the Company to recover the full amount of the poles at the 2019 costs, but not at current day costs. This is a conservative estimate to reflect higher material costs that would have been avoided had DTE been performing industry-standard O&M, as many poles would have been replaced before 2019 had the Company had a more appropriate inspection regime.[647]

In rebuttal, Mr. Robinson countered that Dr. Stultz's claims were speculative noting that her calculation did not account for the time value of money "and is based on hypothetical assumptions that do not reflect actual inspection results or operational realities."[648] Mr. Robinson explained that Dr. Stultz's testimony assumes that DTE would have identified and replaced all of the poles in 2019 that it intends to replace now, and that the Company could have scaled up its PTMM resources to inspect 6,700, rather than

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[646] 4 Tr 3733; Exhibit AA-17.
[647] 4 Tr 3735.
[648] 4 Tr 2045.

1000, circuit miles in 2019.[649] He concluded that Ann Arbor's recommendation should be rejected on grounds that it "does not seek to accurately estimate the correct cost and rates associated with replacing poles and other equipment identified as needing replacement in 2025 and 2026 – it is only intended to penalize the Company for what AA believes should have occurred in the past."[650]

In briefing, Ann Arbor reiterated Dr. Stultz's testimony and Mr. Robinson's rebuttal, responding that contrary to Mr. Robinson's claims, Ann Arbor's recommended adjustment is based on calculations from actual inspections, data provided in the Liberty Audit, and actual materials costs provided by DTE.[651]

Ann Arbor adds that it is not intending to penalize the Company, but to protect ratepayers from higher costs in the future resulting from DTE's imprudent pole inspection program. Ann Arbor adds that its calculation of the disallowance is likely understated because it does not include labor cost increases; it assumes that all delayed pole replacements relate to 2019, rather than earlier, and it accepts DTE's estimates of the number of poles that will need to be replaced rather than assuming a higher number due to a likely backlog.[652]

DTE's initial and reply briefs do not appear to address this issue.

This PFD finds Ann Arbor's recommended disallowance to be reasonable, given the large discrepancy between the Company's pole inspection cycle in 2019 compared to the industry standard of four to five years benchmarked by DTE in the instant

[649] Id.
[650] Id.
[651] Ann Arbor brief, 13-14.
[652] Ann Arbor brief, 14.

proceeding and recommended in the Liberty Audit. As the City points out, the adjustment is conservative, including only the difference in material costs, and not labor; it is not intended to penalize the Company, but it does provide some measure of protection to ratepayers from unreasonable and imprudent actions on DTE's part. This PFD therefore recommends a disallowance of $2,621,701.

d. Capitalization of PTMM Costs

Mr. Stephens expressed concerns about the Company's PTMM capitalization policies and offered his opinion about how the USoA should be applied.[653] According to him, DTE's accounting for PTMM violates the USoA in two ways. First, activities like inspections, testing, and vegetation management should be expensed as O&M, but instead, DTE is capitalizing these costs. Second, Mr. Stephens opined that many of the minor repairs and replacements of pole top equipment, such as crossarms, insulators, and cut-outs, should also be expensed, but DTE is also capitalizing these minor repairs and replacements.[654]

Mr. Alvarez also discussed capitalization in the context of the Liberty Audit, noting that the "vast" audit did not include an accounting audit to investigate whether DTE's accounting practices comply with the USoA, noting that the Company is incentivized to over-capitalize.[655] According to Mr. Alvarez:

> In the long term, Commission approval of unnecessary, premature, cost ineffective, or inappropriately accounted for capital spending has a much greater impact than can be appreciated by viewing customers rates DTE is making artificially low in the short term. DTE is making rates artificially low in the short term by deferring essential O&M activities, and by categorizing O&M activities as capital spending through inappropriate accounting

[653] 5 Tr 4524-4527.
[654] 5 Tr 4524-4525.
[655] 5 Tr 4614-4615.

> practices. Commission reliance on comparative rate statistics, when DTE's rates do not reflect the Company's true cost of service, may not result in the best decisions regarding DTE's capital spending requests. To be sure, increases in capital spending will come home to roost as rate increases in the future. The fact that customers are getting no reliability improvements out of these embedded future rate increases just adds insult to injury.[656]

In rebuttal, Ms. Uzenski testified that Mr. Stephens referenced Exhibit A-28, Schedule R3, which is the BCA for the PTMM, which does not support his testimony because the exhibit does not distinguish between which costs are being capitalized and which are being expensed.[657] She further explained that since 2023, inspection costs related to the PTMM program have been, and are, expensed, up to the point where a problem is discovered and planning begins for capital work.[658]

Turning to vegetation management, Ms. Uzenski disagreed that all such costs should be expensed for the PTMM and other programs that require clearing, stating:

> The Company capitalizes costs directly related to executing its capital PTMM program, and the tree trim work required for safe access to the pole and equipment is being completed to construction specifications (an expanded clearance area). The USoA says that the cost of equipment shall include "expenses incurred by the utility in unloading and placing the equipment in readiness to operate." Tree trimming and other vegetation management required to install capital assets is clearly an expense incurred to place equipment in readiness to operate.[659]

Concerning capitalization of minor repairs and replacements, Ms. Uzenzki disagreed with Mr. Stephens' understanding of minor items, quoting the USoA on the distinction between minor items of property (that should be expensed) and retirement

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[656] 5 Tr 4615-4616.
[657] 4 Tr 2507.
[658] Id.
[659] 4 Tr 2507-2508.

units (RUs) that are capitalized. Ms. Uzenski explained that the USoA requires utilities to maintain lists of minor items and RUs, which are reviewed in depreciation cases.[660]

Ms. Uzenski also took issue with claims by Mr. Alvarez regarding the Company's capitalization policies, explaining that DTE follows the requirements of the USoA as well as GAAP; the Company has internal accounting controls consistent with federal law, and its books and records are reviewed by outside auditor. She opined that Mr. Alvarez's claims regarding the Company's accounting and capitalization practices were entirely speculative and without merit.[661]

MNSC's brief reiterates Mr. Stephens' and Mr. Alvarez's testimony, and it presents a deep dive into the details regarding capital versus expense accounting contained in the USoA.[662] MNSC argues that: (1) inappropriate capitalization enriches shareholders at the expense of ratepayers; (2) the classification of equipment as a minor item or an RU has a significant impact on rate base and DTE has incorrectly designated inexpensive minor items as RUs, contrary to the USoA, as shown in the Company's Retirement Unit Catalog; (3) tree trimming costs are addressed explicitly in the USoA, which requires most of these costs to be expensed, except for first clearing, while the capital account for utility poles does not specifically address tree trimming, contrary to DTE's claims; (4) because DTE takes the position that tree trimming associated with PTMM capital equipment replacement should also be capitalized, DTE has inappropriately capitalized $7.6 million in 2023 and $5.8 million in 2024; (5) MNSC and others have repeatedly raised issues concerning the Company's capitalization practices associated with PTMM in prior rate

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[660] 5 Tr 2509
[661] 5 Tr 2512.
[662] MNSC brief, 157-168.

cases averring that "[t]rimming is maintenance;" packaging it "with recommends capital replacements does not convert trimming into a capital expense."[663]

Pointing to concerns regarding the capitalization policies expressed by the Commission in DTE's last three electric cases, MNSC urges the Commission to review the Company's RU classifications and capitalization policies, especially tree trimming in the context of the PTMM, now that the Liberty Audit is complete. MNSC notes that in the U-21534 order, the Commission stated its intention to begin evaluating utility capitalization policies in another proceeding, and MNSC requests that the Commission provide direction in its order in this case, suggesting that these issue might be addressed in an upcoming depreciation case, and stating that the PTMM capitalization issue provides context for considering disallowance or deferral of PTMM costs.

DTE provides an overview of all testimony, noting that neither Mr. Alvarez nor Mr. Stephens is an accountant or has accounting experience, arguing that their testimony should therefore be given no weight.[664] DTE does not appear to address this matter further in its reply brief.

This PFD agrees with MNSC that DTE's capitalization policies and RU classifications are an ongoing issue of concern and that the Commission should direct either a standalone proceeding involving all of the major utilities or specifically direct DTE to address the issue in its next depreciation case.

4. Subtransmission Redesign and Rebuild

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[663] MNSC brief, 165, quoting MNSC initial brief in Case No. U-21297, p. 117
[664] DTE brief, 55-56.

Mr. Stowe provided a detailed review of the Company's subtransmission system, describing it as "an interconnected web that distributes subtransmission level voltage across the service territory to stations, a critical link between the external transmission system . . . and the Company's distribution system.[665] Mr. Stowe highlighted the age of DTE's subtranmission system and its design that provides significant redundancy in the event of a fault. He also provided details on how the Company plans subtransmission upgrades, providing examples of system overload conditions in DTE's service territory.[666]

Mr. Stowe also discussed the Commission's findings regarding subtransmission investments in Case No. U-21534, and the Liberty Audit. Mr. Stowe stated that DTE agrees in part with the Audit, and in response to the Commission's directives to provide more detail and quantified support for subtransmission investments, he testified that the Company intends to develop a comprehensive, risk-based BCA to be applied to projects over $10 million in DTE's next rate case.[667]

Regarding the Liberty Audit, Mr. Stowe quoted the finding that SRR investments should be limited to investments for capacity reasons and 4.8kV conversions. Mr. Stowe indicated that while he generally agreed, noting that most near-term SRR projects meet that criteria, the Company's plans include four projects necessary for customer reliability and a few driven by other factors.[668] Mr. Stowe presented Table 15 at 2 Tr 151-153, which provides a high-level overview of SRR projects, with more detail provided in Exhibit A-23, Schedule M6 revised.

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[665] 2 Tr 120.
[666] 2 Tr 121-135.
[667] 2 Tr 136.
[668] 2 Tr 136.

Mr. Stowe testified that SRR investments are divided for recovery between base rates as shown in Exhibit A-12, Schedule B5.4.8, and the IRM. As shown in Exhibit A-12, Schedule B5.4, p. 13, line 120, DTE had SRR program spend of $69.5 million in 2023 and projects spending of $43 million in 2024, $43 million in 2025, and $11 million in the test year. This spending is projected to ramp up considerably from the $53.8 million approved for the IRM in Case No. U-21534, to $105 million in 2027, and $115 million and $120 million in 2028 and 2029, respectively. As discussed in more detail below, Staff, MNSC, the CEO and others raise concerns about the proposed spending increases for the SRR program generally, as well as recommending adjustments for certain specific rebuild and conversion projects.

This PFD notes that while Staff initially recommended disallowances or adjustments for several conversion and system loading projects including: 4.8kV Circuit Conversion I-94 (Promenade) (Sched. B5.4, p. 12-13, lines, 41, 48, 55, 92 and 97); System Loading Jewell; 4.8kV CODI Garfield Network Upgrade (Sched. B5.4, p. 12, lines 77-80) CODI Howard Conversion (Sched. B5.4, p. 12, line 82); 4.8kV ISO Circuit Conversion (Sched. B5.4, p. 13, line 83); 4.8kV Circuit Conversion New Baltimore (Sched. B5.4, p. 13, line 84); 4.8kV Circuit Conversion Belleville Sub and Circuit (Sched. B5.4, p. 13, line 85); 4.8kV Circuit Conversion Ann Arbor AC Network (Sched. B5.4, p. 13, line 88); and Hemlock Decommissioning and Circuit Conversion (Sched. B5.4, p. 13, line 90), in its initial brief, p. 70, Staff withdrew its adjustments. These listed projects are not discussed further in this PFD.

a. Transformer High Side Protection Program (Sched. B5.4, p. 11, line 5)

Mr. Stowe discussed DTE's transformer high side protection program, a reliability program to address certain system issues. According to Mr. Stowe:

> Several subtransmission and distribution transformers require the installation of high side protection, either a circuit switcher or breaker, to mitigate observed NERC reportable system issues during simulated contingency conditions that may result in the loss of service to 100+ MVA of customer load. These issues were discovered during annual studies performed by ITC and are required to be mitigated by NERC TPL-001-4 standards.[669]

According to Exhibit A-12, Schedule B5.4, DTE invested $2.277 million in 2023, $1.818 million in 2024, and it projects $6.500 million investment in 2025 and $5.0 million in the test year for the transformer high side protection program.

Ms. Shi testified that while Staff supports the need for this program, it nevertheless questions the lack of justification for the significant increase in spending in 2025 and 2026, noting that DTE had only spent $321,000 on the program as of May 2025. Based on historical average spending adjusted for inflation, Ms. Shi calculated disallowances of $4,563,028 for 2025 and $3,011,502 for the test year. [670]

ITC witness Thompson testified that ITC supports the prioritization of investments in DTE's subtransmission system transformers, explaining that because DTE's system is directly connected to ITC's transmission, faults and equipment failures on DTE's system can affect ITC's infrastructure, impacting transmission reliability.[671] Mr. Thompson stated that ITC supports DTE's prioritization of investments in high side interruption protection devices, explaining "Once installed, these devices will be tripped for DTE transformers or low-side faults and eliminate the need to trip ITCT breakers. This will eliminate [bulk

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[669] 2 Tr 151 (Table 15).
[670] 5 Tr 5007-5008.
[671] 5 Tr 4461.

energy system] BES line flow from being interrupted and improve ITCT's reliability, which is beneficial to the entire state."[672]

In rebuttal, Mr. Stowe pointed to ITC's testimony in support of the program, and stated that "[t]he Company has continued to make improvements to its ability to schedule and execute this work and has laid out a sensible schedule for the overall program in Exhibit A-23 Schedule M6, page 21, with execution stretching through 2034."[673] He added that Staff's adjustment would only serve to delay the project and impact reliability improvements.[674]

The parties' briefs rely on the testimony of their witnesses.[675] DTE reiterates Mr. Stowe's rebuttal, emphasizing that the Company provided substantial evidence supporting its capital expenditures for the SRR programs and projects.[676] Staff states that it acknowledges that DTE may catch up on spending in 2025, and in response to Mr. Stowe's rebuttal, recognizing ITC's support and the Company's intention to progress on the program. Nevertheless, Staff reiterates its concern regarding the minimal spend in 2025, and the lack of implementation details provided in rebuttal.[677]

This PFD finds Staff's adjustment to be reasonable in light of the minimal spend on the transformer high-side protection program in the first five months of 2025. If DTE is able to invest more in 2025 and 2026, additional amounts may be included in a future rate

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[672] 5 Tr 4461-4462.
[673] 2 Tr 190.
[674] Id.
[675] ITC brief, 7-8; Staff brief, 44-45.
[676] DTE brief, 63-66.
[677] Staff brief, 44-46.

case. This PFD therefore adopts disallowances of $4,563,028 for 2025 and $3,011,502 for the test year for the transformer high side protection program.

b. Trunk A3509 and CODI Alfred Substation Expansion (Sched. B5.4, p. 11, lines 28 and 31)

Ms. Shi testified that Trunk 3509 is currently loaded to 100% of its summer rating and 109% of its emergency rating. According to Exhibit A-23, Schedule M6, DTE plans to install or replace several pieces of equipment, with engineering and design completed by 2022 and construction planned for 2023 through 2026.[678]

Ms. Shi reported historical and projected expenditures of $2.295 million in 2023, $1.035 million (of $3.635 million projected) in 2024, $2.2 million in 2025 and $473,000 in 2026 for the Trunk 3509 project. Of the $2.2 million planned spending in 2025, Ms. Shi stated that actual spend was $291,000 in the first five months of the year.[679]

For the Alfred Substation Expansion project, Ms. Shi testified that DTE's historical and projected investment were as follows: $2.893 million (of $3.183 million projected) in 2023; $10.439 million (of $18.235 million projected) in 2024; $6.0 million projected in 2025; and $4.21 million projected in the test year. Ms. Shi noted that of the $6.0 million projected for 2025, $1.563 had been spent.[680]

Ms. Shi stated that Staff supports both projects but is concerned about DTE's commitment to completing the Trunk 3509 project, noting the Company's explanation for underspending in 2024 and that DTE has only spent 15% of its projection by the end of May 2025, which was unexplained.[681] For the Alfred Expansion project, Staff questions

[678] 5 Tr 5008.
[679] 5 Tr 5009.
[680] 5 Tr 5010.
[681] 5 Tr 5009.

repeated underspending of forecasted amounts, again noting the reasons for delays in 2024.[682]

Because of these concerns about underspending, over-projection, and delayed execution Ms. Shi testified that for the Trunk 3509 project, she annualized the five- month spend for 2025 resulting in a disallowance of $1,505,600 in the bridge period.[683] For the Alfred Expansion project, Ms. Shi again annualized the 2025 five-month spend, and calculated a disallowance of $2.249 million in the bridge period. Using the 2025 adjusted amount, plus inflation, she recommended a disallowance of $359,000 for the test year.

In rebuttal concerning the Trunk 3509 project, Mr. Stowe acknowledged the delays in the early stages of the project and that future delays are possible. Nevertheless, he urged the Commission to reject Staff's disallowance, citing DTE's plans to complete the project in 2025 and 2026.[684]

Turning to the Alfred Substation Expansion project, Mr. Stowe testified that work plan for many projects does not require the same amount of spending each month, and construction activities incur the highest costs. But those activities must be scheduled based on material and equipment availability.[685] Mr. Stowe testified that project work plans do not necessarily call for equal monthly spending, thus, Staff adjustment should be rejected.

In briefing, DTE presents a table on pp. 63-65, which is also contained in 2 Tr 173, which quotes Mr. Stowe's rebuttal on the Trunk 3509 and Alfred Substation Projects, and

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[682] 5 Tr 5010.
[683] 5 Tr 5009.
[684] 2 Tr 193
[685] 2 Tr 192.

the Company maintains that Staff's adjustments should be rejected, opining that the Company provided a sufficient level of project detail to demonstrate that the projects would be completed by the end of the test year.[686]

Staff's brief relies on Ms. Shi's testimony, again voicing support for both projects, and acknowledging the reasons for implementation delays. However, Staff argues that DTE should provide detailed and timely updates on project progress, and "[w]ithout such updates, the Company's assurances regarding project execution and spending remain unsubstantiated. Therefore, Staff continues to recommend maintaining the previously identified disallowance until adequate progress and expenditure documentation are provided."[687]

This PFD finds that while the delays and underspend on many of the Company's conversion projects have been acknowledged; and they do appear to result from circumstances beyond DTE's control. Staff's concerns are nevertheless compelling. As Staff indicates, both the Trunk 3509 and Alfred Substation Expansion projects are reasonable and necessary, however, the Company's execution plans are overly optimistic. While DTE makes vague assurances that these two projects are expected to be completed in the test year, the spend amounts in the first five months of 2025 raise doubts. And these doubts are not about the Company's ability to ultimately complete the work; but whether ratepayers are paying significant amounts for investments that are not actually being made, again, due to factors beyond the Company's control.

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[686] DTE brief, 65-66. Apparently, Mr. Chiu also testified regarding Staff's "linear" approach to projecting spend for SRR conversion projects. However, this section of DTE's brief does not provide a cite to his rebuttal testimony.
[687] Staff brief, 47-48, 49.

And while DTE's point that project execution work can be "lumpy," and may not proceed in a linear fashion, is acknowledged, this PFD nevertheless finds Staff's approach to adjusting expenditures to be reasonable. And it goes without saying that if the Company spends more than the amount Staff projects, it can recover those investments in a future rate case. Accordingly, this PFD adopts Staff's recommended disallowances for the Trunk 3509 and Alfred Substation Expansion projects for 2025 and 2026.

c. CODI Targeted Network Secondary Cable (Sched. B5.4, p. 11, line 33)

As set forth in Mr. Stowe's testimony, the City of Detroit Infrastructure (CODI) Targeted Network Secondary Cable project is intended to replace certain secondary network cables that have a high probability of failure. As set forth in Exhibit A-23, Schedule M6, p. 129, in 2024, DTE invested $3.869 million (excluding "Other") for 10,700 feed of cable; DTE projects $4.8 million in expenditures in 2024 for 11,500 feet of cable; and $3.0 million in 2026 for 9,100 feet of cable installed. Ms. Shi noted that DTE spent $1.751 million in the first five months of 2025 for some unknown amount of cable.[688]

Ms. Shi quoted Mr. Stowe's discovery response in Exhibit S-10.1, stating that DTE plans to replace 12,500 feet of secondary network cable and associated equipment in 2025, referencing Exhibit A-23, Schedule M6. Referencing another Company discovery response in Exhibit S-10.1, p. 57, Ms. Shi quoted Mr. Stowe's statement that "other" expenditures "can include but are not limited to administrative and general (A&G),

[688] 5 Tr 5011.

AFCDC, permitting, procurement, contributions in advance of construction (CIAC), and facilities and fleet services."[689]

Ms. Shi testified that while Staff supports the project, it nevertheless has concerns about the Company's proposed spending, stating: "Staff also needs to make sure that every penny that the Company asked for in the case is being spent properly."[690] As such, Ms. Shi explained that Staff excluded "unclear Other" costs from 2024 spending in order to calculate a unit cost for cable in 2025 and 2026, which do not include the "other" cost category. On that basis, Staff calculated a unit cost for cable of $310.18 per foot of cable for 2025 and $318.43 per foot of cable for 2026. As a result of this adjustment, Staff recommended a reduction of $1.233 million for 2025, and $102,303 for 2026.[691] Notably, Ms. Shi testified that even though the Company's discovery response indicated that DTE now plans to replace 12,000 feet of cable and equipment in 2026, Staff used the original 11,500 foot projection in calculating its adjustment. Ms. Shi explained that Staff had "difficulty following the answer either in the discovery response or the details in Exhibit A-23, Schedule M6 as DTE suggested."[692]

In rebuttal, Mr. Stowe disagreed with Ms. Shi's approach for two reasons. First, he explained that the cost and complexity of work in underground construction is variable and dependent on a number of factors including existing conditions of equipment and the presence of hazards that must be addressed. As such, the use of a unit cost for cable is inappropriate.[693] Second, Mr. Stowe explained that Staff's exclusion of "other" costs in

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[689] 5 Tr 5011-5012.
[690] 5 Tr 5012.
[691] Id.
[692] 5 Tr 5012.
[693] 2 Tr 193.

updating 2024 unit costs to 2025 and 2026 was in error because, "[c]harges in the "Other" category in 2024 included valid expenditures required for the execution of the work in 2024, and if a cost per unit were to be calculated, they must be included. Exhibit A-50 Schedule QQ2"[694]

Based on the above, and including "other" costs from 2024, Mr. Stowe recalculated the unit cost for secondary cable in Table 4 at 2 Tr 194, which shows unit costs of $361.56 per foot in 2024, $417.39 per foot in 2025, and $329.67 per foot in the test year.

In briefing, DTE relies on Mr. Stowe's rebuttal testimony, reiterating that costs for underground work can be highly variable, depending on the area being worked on; thus, unit costs are inappropriate for making adjustments.[695]

Staff argues that while it appreciates the Company's clarification in rebuttal, it nevertheless maintains that "other" cost are not relevant to its unit cost calculation, especially because these costs are not included in the 2025 and 2026 costs for the Targeted Network Secondary Cable Replacement project.[696] Staff further takes note of the significant fluctuations in costs presented in Table 4 of Mr. Stowe's rebuttal, which Staff maintains are unexplained.[697]

This PFD agrees with Staff's adjustment for two reasons. First, as Staff points out, the exclusion of "other" costs from 2024 in calculating the unit cost for secondary cable in 2025 and 2026, was appropriate, since these costs were not included in the breakdown of costs for the bridge and test periods. Second, while it is likely the case that the cost of

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[694] Id.
[695] DTE brief, 64.
[696] Staff brief, 51-52.
[697] Id. at 52.

cable installation is quite variable, depending on actual conditions, DTE did not provide sufficient detail to support this purported variability in 2025 and 2026.

d. 4.8kV Grosse Pointe Substation and Circuit Conversion North (Sched. B5.4, p. 12, line 54)

Due to the age of the infrastructure serving the Grosse Pointe area, coupled with loading issues, DTE proposes this project to address age and reliability risk by converting this part of the system to 13.2kV.[698] As shown on Exhibit A-23, Schedule M6, p. 197, DTE projects capital expenditures of $1.5 million for labor for property acquisition activities in the test year.

Ms. Shi testified that although Staff agrees with the project "conceptually" it finds that the Company failed to provide sufficient detail on how the $1.5 million is to be spent on labor hours, due diligence, appraisals, closing costs, etc., to support the request. Staff therefore recommends an adjustment of $300,000, or 20%, until the Company better documents this cost.[699]

In rebuttal, Mr. Stowe explained that the $1.5 million expense was inadvertently included in the "Labor" line of Exhibit A-23, Schedule M6, and should have been included in the "Other" category for expenditures for property acquisition, which should be capitalized under the USoA.[700]

In a general critique of some of Ms. Shi's recommendations regarding the need for more detail, Mr. Stowe testified that DTE has already provided significant detail on all of its redesign projects, pointing to the lengthy Exhibit A-23, Schedule M6. Mr. Stowe opined

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[698] 2 Tr 62.
[699] 5 Tr 5016.
[700] 2 Tr 195.

that including the substantial detail requested by Ms. Shi for every one of the numerous projects done every year "would significantly expand the record with matters that shed relatively little light on whether a project is reasonable and prudent."[701] Mr. Stowe added that this was the first time DTE was asked for this level of detail in a rate case, and recommended that Staff's adjustment be rejected.[702]

In briefing, Staff reiterates that it continues to support the $300,000 disallowance until such time as DTE provides more information, such as preliminary agreements or comparable purchases to support the $1.5 million expenditure.

DTE relies on Mr. Stowe's rebuttal, emphasizing that "Witness Shi's request for granular details as a prerequisite to cost recovery are impractical, unnecessary, and should be rejected."[703]

This PFD finds that Staff's adjustment should be adopted. Contrary to Mr. Stowe's rebuttal claim, that Staff's request for more detail "would significantly expand the record with matters that shed relatively little light on whether a project is reasonable and prudent," this does not appear to be Staff's concern or objective. Staff admits that it supports the project as reasonable and necessary; Staff is simply requesting more information on how the $1.5 million in property acquisition costs was derived, given that property acquisition costs can vary widely based on location. Considering the absence of support for this item, Staff could have recommended a full disallowance, but it did not do so.

e. 4.8kV Circuit Conversion (Melvindale) (Sched. B5.4, p. 12, line 56)

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[701] 2 Tr 203.
[702] 2 Tr 204.
[703] DTE brief, 64, 66.

According to Table 2 presented by Mr. Stowe at 2 Tr 62, the 4.8kV Melvindale circuit conversion involves the construction of a new substation due to capacity and reliability concerns.

Ms. Shi testified that for 2026, DTE projects expenditures of $1.8 million for "Other," as shown in Exhibit A-23, Schedule M6, p. 201.[704] Ms. Shi explained:

> The Company's supporting materials create confusion in cost classification for property acquisition (e.g., treated as 'labor' in related items, and 'Other' here). Absent a detailed purchase contract and a clear accounting treatment, Staff recommends a precautionary adjustment to disallow $360,000 (20 % of $1,800,000) unless the Company provides the executed or draft purchase agreement(s), itemized transaction costs, and a clear capitalization policy showing the appropriate classification of property acquisition costs.[705]

Mr. Stowe disagreed, noting that DTE made the same categorization error here as it did with the Grosse Pointe Substation and Conversion North project discussed above, reiterating that DTE follows the USoA for categorizing property acquisition costs and again explaining that Staff is requesting excessive and unnecessary detail.[706]

DTE's brief relies on Mr. Stowe's testimony, and its general objections to the level of detail Staff requests here.[707] Staff's brief acknowledges Mr. Stowe's clarification in rebuttal regarding classification of costs and the Company's adherence to the USoA, but it maintains that "the details of what the funds will be spent on are still absent."[708]

This issue concerning the Melvindale conversion mirrors the one discussed above regarding the Grosse Pointe conversion. Again, Staff is not questioning the

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[704] 5 Tr 5017.
[705] Id.
[706] 2 Tr 197.
[707] DTE brief, 64.
[708] Staff brief, 57.

reasonableness and prudence of the project in general, it is merely attempting to ascertain the basis for DTE's projected cost for land acquisition. Mr. Stowe's direct testimony in Table 2 at 2 Tr 62, indicates that "[t]here is an opportunity to purchase property that will allow for the construction of a new 13.2kV substation that will help address the overloading issues in the area." Fleshing this out with a real estate listing or buy-sell agreement in discovery or rebuttal might have been sufficient support for this item; but the Company failed to provide any additional details. Consistent with this discussion, Staff's recommended adjustment of $360,000 is adopted.

f. Pontiac Conversion (Sched. B5.4, p. 12, line 61; p. 13, line 101)

MNSC recommends that the Commission disallow $20.7 million for the Pontiac Conversion, comprised of $15.8 million for the overhead conversion and $4.9 million for the underground conversion in the test year.

As a general matter, Mr. Stephens testified that DTE is proposing a total of $279.8 million in circuit conversion spending in the test year, "the highest single-year conversion program budget to date" as shown in Figure 11 at 5 Tr 4534. Mr. Stephens opined that if DTE continues this level of capital spending on conversions, it is possible that the Company will convert all circuits to 13.2kV by 2040. However, he questioned the wisdom as to whether DTE *should* convert all circuits to 13.2kV within the next 15 years.[709]

Turning to the Pontiac conversion specifically, Mr. Stephens explained that that project was called out in particular in the Liberty Audit, which generally found that DTE's conversion program should be limited to only those conversions needed for substation

[709] 5 Tr 4534.

capacity reasons and that the Pontiac conversion specifically appeared to be a project that does not need to be executed in the near-term.[710] Mr. Stephens concluded that given the high cost of the Company's conversion plan, the Pontiac overhead and underground conversion projects "present a reasonable deferral opportunity . . . [i]f the Commission is looking for low-risk ways to defer capital spending – as I believe it should be[.]"[711]

In rebuttal, Mr. Stowe took issue with Mr. Stephen's reliance on the Liberty Audit, referring to his direct testimony on the challenges posed by the Pontiac area's unique 8.3kV voltage, aging equipment, and increasing load, which affect reliability and operability.[712] Mr. Stowe reiterated that because the Pontiac area is a unique 8.3kV voltage, it cannot be restored or tied to any other circuit except another 8.3kV circuit, leaving the possibility of stranded load in the event of an outage.[713]

Next, Mr. Stowe highlighted an event on August 19, 2024, where over 1,000 customers were affected by an outage that lasted 12 hours. He also detailed an incident that occurred on July 24, 2025, when a substation in Pontiac experienced a significant failure and the outage continued for 13 hours due to difficulties in obtaining the necessary parts. According to Mr. Stowe, had the transformer failed, customers would likely have been out for days as DTE developed a contingency plan, necessitated because 8.3kV parts are not available, and the Pontiac substation cannot be tied to a 13.2kV circuit. As such, Mr. Stowe disputed that a deferral of the Pontiac conversion is a low-risk means to defer conversion costs.[714]

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[710] 5 Tr 4536.
[711] 5 Tr 4539-4540.
[712] See, 2 Tr 101-106.
[713] 2 Tr 221-222.
[714] 2 Tr 222-223.

In briefing, MNSC points to the Liberty Audit, as well as the Commission's finding in Case No. U-21305, p. 33, agreeing with the Audit findings, and directing the Company to "quantify the risk associated with maintaining the status quo and present analyses to better justify whether the Pontiac conversion should be a priority over other projects where greater benefit could be achieved for the same costs or less, particularly considering that Pontiac was not among 2023's worst performing circuits." The Commission further ordered DTE to provide a BCA in future proceedings where capital investments for the Pontiac conversion are requested.[715]

In response to Mr. Stowe's rebuttal, MNSC posits that DTE's concerns about reliability, safety, and operability challenges associated with the Pontiac area were taken into account and addressed in the Audit, quoting Part II of the Audit at p. 89. In response to Mr. Stowe's testimony about outages in 2024 and 2025, MNSC argues that Mr. Stowe "offers similar anecdotes throughout his testimony supporting other capital programs. However, anecdotes about a couple outage incidents in a two-year period are not evidence of a pervasive problem nor do they overcome the findings by Liberty and the Commission that the Pontiac 8.3 kV circuits are not among DTEE's poor-performing circuits."[716]

Lastly, MNSC points out that contrary to the Commission's clear direction, DTE did not provide the additional analysis the Commission called for in its order in Case No. U-21305, maintaining that DTE offers nothing new here, "it simply rehashes it unsuccessful arguments from the audit proceeding."[717]

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[715] MNSC brief, 84.
[716] MNSC brief, 86.
[717] Id.

In its initial brief, DTE faults Mr. Stephens for having a limited understanding of the Company's system "and for that reason alone . . . his recommendation should be rejected," noting in particular Mr. Stephen's failure to discuss the limited options for addressing outages on the 8.3kV system, including the fact that it cannot be tied to surrounding 13.2kV circuits in the area.[718]

This PFD agrees with MNSC that the amounts proposed for the Pontiac area conversion project should be disallowed. As MSNC point out: (1) whether or not Mr. Stephen's testimony addressed all of the specifics of the Pontiac system, the Liberty Audit, specifically addressed the limitations of the Pontiac circuit and still recommended deferral of the conversion in light of more pressing needs; (2) the Commission also addressed the Pontiac conversion in particular and directed the Company to provide more support in the form of a BCA if it requests further capital for the Pontiac conversion program; and (3) stories are not data, and should not form the basis for tens of millions of dollars in capital investments that do not need to be expended immediately.

Consistent with the above discussion, MNSC's recommended disallowances should be adopted.

g. Trunk 7105 (Sched. B5.4, p. 12, line 70)

According to Mr. Stowe's Table 2 at 2 Tr 153, the SRR Trunk 7105 is overloaded to 133% of summer normal capacity rating and 127% of DTE's summer emergency rating, violating the Company's subtransmission planning criteria. To address this concern, DTE

[718] DTE brief, 68.

plans to implement an emergency load control scheme at the Brooks and Sargent substations.[719]

According to Ms. Shi, DTE invested approximately $246,000 and $540,000 in 2023 and 2024, respectively, and it projects no spend in 2025 and $1.0 million in 2026 for "labor"[720] Ms. Shi stated that while Staff supports the emergency load control scheme, the Company did not provide details about the $1.0 million 2026 spend. Given the lack of information on the projected investment, Staff recommends that 20% or $200,000, be disallowed for the test year, "unless the Company provides a complete bill of materials with costs, labor plan, and schedule consistent with the stated milestones."[721]

In rebuttal, Mr. Stowe countered that DTE has "provided an appropriate level of detail" in Exhibit A-23, Schedule M6, p. 238-241.[722] He also pointed to Exhibit A-50. Schedule QQ3, which indicates that DTE plans to complete detailed engineering, complete inspections, and undertake detailed design in the test year. He also referred to his testimony about the unnecessary level of detail Staff is requesting in this case.[723]

In briefing, DTE relies on Mr. Stowe's testimony, emphasizing that Exhibit A-23, Schedule M6 provides "a high-level project scope and milestone schedule."[724] Staff argues that rebuttal Exhibit A-50, Schedule QQ3 provides no more information than DTE originally provided.[725]

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[719] 5 Tr 5018.
[720] Id.
[721] Id. at 5019.
[722] 2 Tr 198.
[723] 2 Tr 198.
[724] DTE brief, 64.
[725] Staff brief, 59.

This PFD agrees with Staff that Exhibit A-50, Schedule QQ3 does not provide any additional information beyond what was provided in DTE's initial filing, and that Exhibit A-23, Schedule M6, pp. 241 provides an approximate construction schedule and an indication that the budget basis is "Project Management Estimate." The line for "Total Labor (DTEE & Contractors)" indicates projected spend of $1.0 million, with no material or other costs forecasted. Thus, this PFD finds that Staff's 20%, or $200,000 adjustment is reasonable and recommends its adoption.

h. Reverse Power Relay Scheme (Sched. B5.4, p. 12, line 71)

The objectives and plans for the Reverse Power Relay Scheme are set forth in Table 2 of Mr. Stowe's testimony at 2 Tr 153.

Ms. Shi testified that there was no program spending in 2023, and for 2024, DTE spent $17,000 of $150,000 projected. As of the end of May 2025, DTE had spent $6,000 of $1.0 million projected, and the Company also projects $1.0 million in 2026.[726]

While Staff agrees that the program is necessary, Staff again raises a concern about DTE's execution of the program, compared to spending projections. According to Ms. Shi, "[a] reasonable adjustment is warranted pending evidence of ramp-up capability and committed work packages." Staff therefore recommended a disallowance of $200,000 for 2025 and $200,000 for 2026.

In rebuttal, Mr. Stowe stated that while he agreed that there have been project delays in 2025, "full execution is expected in 2026."[727]

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[726] 5 Tr 5019.
[727] 2 Tr 199.

This PFD agrees with Staff that a 20% reduction for both 2025 and 2026 is reasonable, in light of the significant over-projections in 2024 and 2025. If DTE invests more in this program in 2025 or 2026, it may request recovery in a future rate case.

i. Ann Arbor AC Network Conversion (Sched. B5.4, p. 13, line 88); 4.8kV Grosse Pointe Sub and Circuit Conversion (Sched. B5.4, p. 13, line 89); Birmingham (Sched. B5.4, p. 13, line 94); Hilton (Sched. B5.4, p. 13, line 96); BRITN (Sched. B5.4, p. 13, line 98); Pittsfield (Sched. B5.4, p. 13, line 99)

A high-level overview of these projects is set forth in Table 2 of Mr. Stowe's testimony at 2 Tr 60-66, with more detail provided in Exhibit A-23, Schedule M6.

Although MNSC's primary recommendation for circuit conversion spending is to hold investment levels to the 2023 historical amount, adjusted for inflation, in the alternative, MNSC recommends disallowances totaling $5,821,000 in the bridge period and $20,642,000 in the test year for the listed projects, in addition to the Pontiac conversion project discussed separately above. In her initial brief, the Attorney General concurs with MNSC's recommendations for conversion projects.[728]

MNSC cites several grounds for its recommendations: (1) the Liberty Audit found that DTE has not justified the pace of its conversion spending; thus, the Audit recommended that DTE limit conversion investments to only those necessary for capacity reasons; (2) the Commission, in discussing the Audit in the U-21305 order, pp. 29-30, found that DTE's support for conversions is lacking, and in future funding requests, the Company needs to provide more analysis, including an assessment of cost-effective alternatives to circuit conversions; and (3) despite the recommendations in the Audit and

[728] Attorney General brief, 155-157.

the Commission's directives, DTE's presentation in this case on circuit conversions largely mirrors the Company's presentation in Case No. U-21534.[729]

Related to this last point, according to MNSC:

> DTEE witness Ryan Stowe's direct testimony on conversions mostly tracks DTEE witness Satvir Deol's testimony in U-21534. While some of the projects are different, the general descriptions of challenges to the existing system and the claims of benefits from conversions are nearly the same. Many of the figures are the same. There is no analysis of alternatives for any of the projects; no assessment of conversions versus hardening; no consideration of balancing capital investment with O&M; no discussion of the cost impacts of increasing conversions expenditures by $106 million over the 2023 historical year; and no discussion of DTEE's capacity to ramp up execution of the program by such a large amount.[730]

Regarding the capacity justification for DTE's 4.8kV conversions, Mr. Stephens testified that only 5.7%, or 111, of DTE's 2,000 4.8kV circuits exceed their day-to-day equipment ratings on peak days, "meaning that the sense of urgency to accelerate the pace of circuit conversions is low."[731] Despite this, and considering that DTE's load growth on its system overall is low, the Commission has approved an average of $200 million per year for conversions from 2023 through 2025, with cost recovery through the IRM and base rates.[732]

Mr. Stevens suggested that the best way to address the issue of accelerated spending on conversions, along with deferring projects where capacity is not an immediate concern, is to have DTE work with Staff and other interested parties, "to establish standards and protocols for load forecasting, objective thresholds for project approval, objective thresholds for substation retirement/multi-circuit projects, project

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[729] MNSC brief, 76-77.
[730] Id. at 77 (internal citations omitted).
[731] 5 Tr 4537.
[732] Id.

budgeting and cost tracking, and so on."[733] Mr. Stephens emphasized that this should be done before significant spending occurs, noting that it would be difficult to end projects that are already underway.[734]

This PFD agrees with Mr. Stephens' observation that ongoing projects, except for the Pontiac conversion, would be difficult to terminate at this point. A review of Exhibit A-12, Schedule B5.4, p. 13, shows that the Ann Arbor, Grosse Pointe, and Birmingham areas appear to involve ongoing conversion projects. For these projects there has been spending, in some cases significant sums, since 2023, and terminating these projects now could be disruptive, and could potentially increase costs.

However, for the Hilton, BRITN, and Pittsfield projects, there has been little, if any investment before the test year, and this PFD finds that these projects could perhaps be deferred as MNSC points out.

For the Pittsfield substation and circuit conversion, according to Exhibit A-23, Schedule M6, p. 319, a significant amount of EV adoption, coupled with Ann Arbor's commitment to be carbon neutral by 2030, including elimination of natural gas space heating, results in a projected 18% load growth over the next 15 years. In addition, two of the circuits fed by the substation exceed the distribution design order (DDO) limit.

MNSC points to cross examination of Mr. Stowe, who did not know how many circuits were in the Pittsfield area; he was unable to identify the location of Pittsfield Township or confirm whether it has the same carbon neutrality goals as Ann Arbor,[735]

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[733] 5 Tr 4538.
[734] 5 Tr 4538.
[735] As MNSC notes, Mr. Stowe determined that the Pittsfield substation serves both Pittsfield and part of Ann Arbor, although the extent to which the substation serves Ann Arbor is unknown.

however, he did confirm that the Pittsfield substation is not over its firm rating.[736] MNSC argues that based on this limited information, "there is no credible capacity justification for the Pittsfield conversion project." MNSC recommends disallowances of $152,000 in the bridge period and $1,084,000 in the test year.

DTE responds that although Mr. Stephens opines that DTE should be responsive to findings in the Audit and the Commission's order in U-21305, he fails to recognize that DTE filed its case before the Commission issued its order, and therefore any directives in that order should only apply to future filings. In addition, with respect to all of the conversion projects in dispute, Mr. Stephens' general recommendation that the Company only begin planning conversion projects when the area is 90% loaded, "is inconsistent with good utility planning practice and could result in reliability violations that affect customers served by this equipment. The Company's engineers—not witness Stephens—have the knowledge and understanding that is specific to the Company's infrastructure and operational challenges."[737] DTE adds that the Company has no plans to convert all circuits, but it will continue planning conversions for the next five years to address capacity needs.[738]

In response to MNSC's specific recommendations regarding the Pittsfield conversion, DTE reiterates the information provided in the Company's application (Exhibit A-23, Schedule M6, pp. 319-322).

This PFD finds that the Commission should approved MNSC's adjustments of $152,000 in the bridge period and $1,084,000 in the test year for the Pittsfield conversion.

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[736] MNSC brief, 83, citing 2 Tr 279-280; 311-313.
[737] DTE reply, 53.
[738] DTE reply 54.

The PFD is not persuaded that the conversion must be undertaken in the near term. Although there may be some load growth in the City of Ann Arbor, and the Pittsfield substation does serve some City load, the Company's forecast of load growth in Ann Arbor is speculative, and scarce funding should be dedicated to higher-priority projects.

Turning to the Hilton Road substation and conversion project, MNSC observes that the project detail in Exhibit A-23, Schedule M6, pp.89-90, indicates that ""the initiative area has about 43.9MVA of load that is covered by (21) load-carrying circuits. The circuits are limited to 3MVA DDO."[739] MNSC cites Exhibits MEC-2 and MEC-5 and cross examination of Mr. Stowe, where he clarified that the DDO limit "is based on guidelines that the U.S. Department of Agriculture uses to loan money to rural electric cooperatives." Further, Mr. Stowe confirmed that the Hilton Road circuits are not operating over their DDO limit, and, according to MNSC even if they were, the GPM gives less weight to DDO limits than to other constraints.[740] MNSC asserts that based on these facts, there is no capacity constraint and therefore recommends a disallowance of $900,000 in the bridge period and $9.407 million in the test year for the Hilton Road project.

DTE reiterates that Mr. Stephens' opinions are presented in the abstract, and he has no personal knowledge of DTE's system. DTE adds that his recommendations are inconsistent with good utility planning practice, and if adopted, could result in reliability issues for DTE customers. DTE again provides the information on the Hilton Road project from Exhibit A-23, Schedule M6, pp. 311-314. Notably, the information discusses the

[739] MNSC brief, 81.
[740] MNSC brief, 81-82, citing Exhibit A-23, Schedule M8, p. 92.

"potential for stranded load," and a construction schedule that begins in 2025 ends in 2032.[741]

This PFD agrees with MNSC that this project could likely be deferred, until such time as DTE provides more support for the need for additional capacity in the Hilton Road area. The Company mentions providing capacity to new businesses in downtown Ferndale and the State Fairgrounds area but does not provide a forecast for how much the load is expected to increase. Therefore, this PFD recommends disallowance of $9.407 million in the test year for the Hilton Road project, with no disallowance for the bridge period. The Company may provide more support for this project for consideration in a future rate case.

Lastly, concerning the BRITN project, Exhibit A-23, Schedule M6, indicates that there may be a capacity concern if both substation transformers fail at the same time. MNSC points out that there is no information on the likelihood that both transformers would fail simultaneously, MNSC further states that the BRITN substation is at 72% of firm capacity; well below the 80% threshold where DTE begins planning a system load project.[742] Given that that this does not appear to be a capacity-related project, MNSC recommends a disallowance of $900,000 in the test year.

DTE's response, as noted above, disagrees with Mr. Stephens assessment, and the Company insists that its engineers and planners are better positioned to understand the needs of DTE's system.

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[741] DTE brief, 55.
[742] MNSC brief, 82, citing 2 Tr 276-278.

This PFD agrees that based on the evidence in this record, there has not been past spending on the BRITN project, and the proposed project appears to be more reliability- than capacity-based. As such, this PFD agrees that test year spend of $900,000 should be disallowed.

Finally, this PFD agrees with witness Stephens' recommendation for DTE, in collaboration with Staff and other interested parties, to develop more concrete planning protocols and guidelines to inform the pace of circuit conversions. The Commission could consider directing DTE to form a workgroup or collaborative to this end.

5. System Loading Projects

a. Overview and MNSC Adjustments

Mr. Stowe testified that System Loading Projects are investments to address distribution system overloads to improve reliability and provide additional capacity. Mr. Stowe noted that these projects tend to be focused on the 13.2kV system, "but may include 4.8kV areas if full 13.2kV conversion of the area is not warranted at this time."[743]

Mr. Stowe explained that a system overload occurs on a circuit or substation "when there is insufficient capacity in certain operating conditions to meet customer demands while maintaining grid operation within equipment operating ratings."[744] He added that system loading projects can increase capacity and may include construction of a new substation (including property acquisition), expansion of an existing substation, equipment replacement, and circuit replacement or conversion.[745]

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[743] 2 Tr 107.
[744] Id.
[745] 2 Tr 107-108.

Mr. Stowe provided an extensive discussion on system overloading, explaining that capacity needs are evaluated under two conditions: (1) normal state, when all equipment is operating as designed; and (2) contingency state (or emergency state), when there is a planned or unplanned equipment shutdown or failure other where equipment on the system may see an increase in loading due to the shutdown or failure. He added that "[t]o meet the normal and contingency state capacity need of the system, most components . . . have two ratings: day-to-day and emergency." The ratings are calculated to ensure that the equipment lasts through its expected life. If equipment is operated above its ratings, it may fail immediately or may reach end-of-life sooner. Mr. Stowe testified that "DTE Electric definitions for day-to-day rating, emergency rating, and substation firm rating are consistent with industry definitions such as those available from National Electric Reliability Corporation [NERC]," adding that substation "firm rating" is the maximum load that a substation can carry in an emergency (e.g., the failure of another piece of equipment in the substation), and is based on the lowest rating of any substation equipment that serves load.[746]

Mr. Stowe discussed the issues with overloading including stress on equipment, reliability issues, and limited capability to serve new customer load, issues that the system loading projects are intended to address, with the objective to ensure that "substations shall be under 100% of firm rating, and all equipment shall be under 100% of day-day rating."[747]

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[746] 2 Tr 108-109.
[747] 2 Tr 112-113.

Next, Mr. Stowe discussed how DTE determines where overloads exist (or may exist in the future) on the system, including adjustments for future load growth (new customers, electrification, EV integration). According to him, based in the Company's 2024 assessment, 12.3%, or 69 substations are operating over firm rating in DTE's system. In addition, 18.7% of circuits are operating over planning criteria.[748]

According to Mr. Stowe, System loading projects are prioritized by: (1) substation overloads; (2) circuit equipment overloads; (3) substation operating over firm ratings; (4) extensive load growth or circuits over 8MVA for 13.2kV circuits or over 3MVA for 4.8kV circuits. Mr. Stowe presented the list of proposed system loading projects on Exhibit A-12, Schedule B5.4, p. 12, lines 62-66 and 102-116. He noted that DTE spent $14.2 million in the 2023 historical year and projects investment of $70.5 million in the test year. Details of the project are included in Exhibit A-23, Schedule M6, and Mr. Stowe provided a high-lever overview of the projects in Table 9, at 2 Tr 116-119.[749]

MNAG witness Stephens outlined DTE's system loading program, describing it as similar to the SRR program and noting that many of the projects are justified by DTE's distribution design order (DDO) capacity limits that were adopted in 2016. He reiterated that rebuilding existing infrastructure for the sole purpose of complying with new standards is "atypical" and capacity limits, such as those contained in the DDO, are not absolute, and planning criteria should be more nuanced in determining overloads. Lastly, he testified that addressing system loading is an increasingly expensive proposition and

[748] 2 Tr 114.
[749] Id.

that the Company should not simply used the “arbitrary” DDO standard in prioritizing projects.[750]

Turning to the Company’s proposed investment amounts in system loading, Mr. Stephens testified that not only is the $70.5 million capital expenditure proposal for the test year the highest amount ever for this program, test year spending “represents just a portion of spending for a suite of 18 System Loading projects to be completed by 2031 at a cost of over $925 million,” presenting Figure1, which illustrates historical and projected spending on system loading, and Table 1, which details the test year spending and total costs for the 18 projects proposed, at 5 Tr 4512 [751]

Mr. Stephens testified that he reviewed load history for 15 of the 18 projects, finding that loads have mostly been flat or falling for most circuits in recent years, and that for circuits that have been overloaded, those conditions have been present, and apparently managed for several years. He also observed that in the project documentation provided, the Company did not present an alternatives analysis, which is typically expected. Less costly alternatives include grid reconfiguration to transfer load, DR programs, and BESS, all of which should be evaluated before committing to costly substation upgrades or replacements.[752]

Turning to the Liberty Audit findings, Mr. Stephens testified that the Audit found that DTE’s lack of ability to forecast loads at a circuit level was a deficiency. He opined that “[t]his capability is critical to load forecasting and capacity planning and is something

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[750] 5 Tr 4509-4510.
[751] 5 Tr 4511
[752] 5 Tr 4513-4514.

that I have never observed at any investor-owned utility."[753] He further observed that the auditor did not have project-level cost information and appeared to have accepted DTE's claim that one-third of its substations have exceeded capacity guidelines. For DTE the guideline is 80% of firm capacity rating, "however for a utility like DTE experiencing low to no load growth, this is likely too conservative."[754]

While first acknowledging that even when a utility is experiencing little or no load growth overall, it does not follow that no system loading investments need be made; given that there may be growth that must be accommodated in certain areas, "[h]owever, it does mean that capital spending budgets that have historically accommodated pockets of load growth in the past will likely continue to be adequate for accommodating pockets of load growth in the future," noting that the Company's investments in system loading averaged $27.8 million per year from 2023-2025.

Lastly, Mr. Stephens identified 12 projects, shown in Table 2 at 5 Tr 4517, which based on his analysis, showed flat or falling load, or unsubstantiated growth forecasts that also lacked quantitative data analysis of safety or reliability benefits associated with the proposed spending. The projected test year spending on these projects totaled $45.3 million, which Mr. Stephens recommended be disallowed. He further recommended that DTE should be required to develop a circuit-specific load forecast capability before filing its next rate case and that the Commission should require the Company to provide greater support for its system loading program, including a risk-informed BCA, as is required for SRR projects.[755]

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[753] 5 Tr 4516.
[754] Id.
[755] 5 Tr 4518.

In rebuttal, Mr. Stowe disagreed, stating that Mr. Stephens appeared to misunderstand the Company's rationale for system loading investments, pointing to his conclusion that DTE bases its need for these projects on DDO limits of 8 MVA for 13.2kV circuits and the 2016 DDO. Mr. Stowe explained that this is incorrect, and that DTE's investments "are driven by current distribution system issues and address current substation overloads (i.e., substations loaded over their firm rating)."[756] He presented Figure 1 at 2 Tr 209, to illustrate different levels of current overloading conditions, noting that when overloading occurs, the Company first undertakes a smaller-scale solution, such as transferring load to another circuit, or upgrading the limiting element, adding that "[p]rojects in the System Loading category are addressing system or area problems and are not focused on DDO violations or single distribution circuits as implied by Witness Stephens."[757] He explained that none of the 12 projects that Mr. Stephens recommended for disallowance use DDO for 13.2kV circuits as justification for the project, and all of them are substations operating over their firm rating, thus overloaded.[758]

To illustrate this point, Mr. Stowe presented Table 5 at 2 Tr 211, which shows the firm rating, 2025 load forecast, and 2025 projection of percentage of firm rating for all of the projects in question. Except for Sterling, which is a special case, the 2025 forecast ranges from 99.8% to 129% over firm rating for each of the substations.[759] He further observed that Mr. Stephens appeared to be in agreement, as evidenced by his statement

[756] 2 Tr
[757] 2 Tr 208.
[758] 2 Tr 210.
[759] Table 5 is partially redacted in the public transcript, but is available at 2 Tr 364 Confidential.

that “When a load growth forecast indicates a substation’s firm capacity rating is likely to be exceeded in the next three to five years, conversion planning should commence.”[760]

Turning to the Liberty Audit, Mr. Stowe opined that the report confirms the Company’s planned investments, finding that DTE has a number of substations that exceed planning criteria and that are in need of support.[761]

Next, Mr. Stowe discussed DTE’s load forecasts, presenting Table 6, which he testified contains information that MNAG did not request in discovery, but that is necessary to fully analyze the proposed system loading projects. According to him, “Since the substations associated with these projects are already over their firm rating, any load growth only further exacerbates the loading problem at the substation. Thus, there is load growth on the 12 projects and Witness Stephens’s recommendation should be rejected.”[762]

In response to Mr. Stephens’ recommendation that the Company perform a BCA to support future investments in system loading projects, Mr. Stowe testified that such analyses are not generally done because these projects are not discretionary due to the risk of catastrophic failure, providing an example of such failure at the Jupiter substation in 2025.[763]

Lastly, Mr. Stowe testified that, contrary to Mr. Stephens’ claims: (1) DTE did provide load forecasting information to MNAG as requested, pointing to Exhibit A-50, Schedule QQ4; (2) PTMM and other routine O&M activities will not address the

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[760] 5 Tr 61.
[761] 2 Tr 210.
[762] 2 Tr 213.
[763] 2 Tr 214-215.

overloading issues in the Company's system; (3) DTE's 13.2kV DDO is not arbitrary, "the DDO is the planning criteria, and it is the basis that an engineer uses to design a particular piece of equipment or portion of the electrical system;" (4) DTE did provide safety reliability information regarding the system loading projects to MNAG, again citing Exhibit A-50, Schedule QQ5;

In briefing, MNSC argues that DTE has failed to show that many of the substations are overloaded, contending that DTE has "redefined" overloaded for existing infrastructure by using criteria for new equipment. In addition, MNSC argues that even if some of these projects are approaching overload, the Company refused to provide evidence that could verify its claims regarding load growth. Accordingly, MNSC recommends a disallowance of $43.5 million in test year expenditures for the 12 substations addressed in Mr. Stephens' testimony, Alternatively, MNSC recommends a test year disallowance of $13.8 million for Mohican, Chesterfield, Cody, Disco, Kings Point, and Sterling projects.[764]

DTE responds that although Mr. Stephens claimed that implementation of the projects violates the Company's planning guidelines, in fact, the Company demonstrated that the proposed projects are currently overloaded. DTE reiterated that the Company typically undertakes smaller-scale solutions, but these projects are past the point where such remedies will work.[765]

This PFD finds that the preponderance of the evidence shows that the substations at issue are, or will soon be, overloaded. Therefore, DTE's proposed investments in the

[764] MNSC brief, 64-72.
[765] DTE brief, 66.

12 substations at issue should be approved. However, as suggested by MNSC, future proposed projects should also include an analysis of alternatives such a focused DR, BESS, or grid reconfiguration, as potentially more economical options that might at least delay costly substation expansion or replacement.

b. Staff Adjustment (Grenada) (Exhibit A-12, Sched. B5.4, p. 13, line 108)

Mr. Stowe testified that the Grenada project will provide system loading, conversion, and automation benefits. He explained:

> The first step of the project was to rebuild and convert a portion of an adjacent Prospect substation circuit to deliver improved reliability from the rebuild, but also mitigate an overload at Prospect substation which was over 100% of firm rating and exceeded 100% of its emergency rating in 2018 (4.2 MVA loading vs 4.1 MVA rating). To address the circuit overloads, approximately half of a Prospect substation circuit has been transferred over to a Grenada substation circuit as of 2024 (summer loading of 2.1 MVA remains at Prospect). To support projected circuit/area needs, construction of a new Grenada substation is planned and will increase capacity by 77% versus the existing Grenada substation, providing capacity for continued growth and mitigating circuit overloads. Finally, additional planned circuit conversions and establishment of additional circuits will enable installation of loop schemes and circuit automation, none of which are possible without the capacity delivered in the system loading project. When fully implemented, the project is anticipated to deliver an 88% improvement in reliability versus three-year (2020-22) historic SAIDI for the area.[766]

Ms. Shi testified that DTE projected $3.521 million in 2023, of which it spent $2.853 million, $6.535 million was projected for 2024, of which $3.280 was spent. For 2025, DTE projected $12.0 million but as of the end of May, DTE had only spent $1.069 million. DTE projects $8.867 million for the test year.[767] Ms. Shi stated that while Staff supports the upgrade, it has concerns about the previous underspending on the project and

[766] 2 Tr 113.
[767] 5 Tr 5028.

recommends adjustments for 2025 and 2026 based on annualizing the five-month 2025 investment. This resulted in a proposed disallowance of $10,266,233 in 2025, and $6,233.274 for the test year.[768]

In rebuttal, Mr. Stowe acknowledged the delay in 2025, which was the result of permitting issues, but indicated that the 2026 scope of work is expected to be completed.[769]

In its brief, Staff argues that DTE provided no update on 2025 spending and no details on how the Company will accomplish the full scope of work in 2026. Thus, Staff maintains its recommended disallowances.[770] DTE's initial brief relies on Mr. Stowe's rebuttal regarding permitting issues and his claim that the 2026 work will be completed.[771]

This PFD agrees with Staff that, in light of DTE's overly optimistic projections and resulting underspend from 2023-2025 on the Grenada project, Staff's recommended adjustments should be adopted. If DTE is able to catch up on this project, the Company can request approval of additional amounts in a future rate case.

6. Substation Risk Projects

Mr. Robinson discussed Major Event Risk projects, which are "projects designed to remediate failures that have already occurred or to prevent catastrophic failures in the future."[772] This spend category is divided into substation risk projects, DTE's mobile fleet

[768] 5 Tr 5028-5029.
[769] 2 Tr 201.
[770] Staff brief, 70.
[771] DTE brief, 65.
[772] 4 Tr 1997.

program, and portable generators.[773] The Attorney General recommended disallowances in both substation risk projects and the mobile fleet program.

a. Substation Risk

Mr. Robinson testified that substation risk projects are intended to address failures of substations that have already occurred or "to prevent catastrophic substation failures in the future."[774] Noting that substation failures typically occur due to equipment failure, flooding or fires, he explained that because a substation generally serves several circuits, a failure has the potential to impact a large number of customers, and due to the type of equipment used in a substation, repairs may take longer, resulting in longer outages if the mobile fleet cannot be deployed to restore power. Accordingly, Mr. Robinson explained that substation risk projects are prioritized in the GPM to address repairs at substations where the mobile fleet cannot be utilized. [775]

As shown in Exhibit A-23, Schedule M5, Mr. Robinson testified that DTE included 13 substation risk projects in this proceeding, including two flood-related projects (McGraw and Flood Defense program), which were approved for cost recovery in DTE's previous rate case.

Mr. Coppola explained that, as set forth in Exhibit A-12, Schedule B5.4, p. 10, lines 19-29, DTE projected capital expenditures of $27.1 million in 2025 and $5.625 million in 2026, for five ongoing substation risk projects (Apache, Drexel, Chestnut, Hood, and McGraw).[776]

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[773] Id.
[774] 4 Tr 1998.
[775] Id.
[776] 4 Tr 3449.

Mr. Coppola testified that when asked in discovery about the number of substation failures and customers affected, along with a BCA and SAIDI, SAIFI, and CAIDI impacts from substation repair from 2019-2024, the Company responded that it had not undertaken a BCA or reliability analysis. In terms of substation failures and outage impacts, Mr. Coppola testified that the response "shows an erratic pattern with power outages, durations, and frequency changing wildly from year to year with no specific trend of increased deterioration or improvement, despite some work remediation and spending already done at some of the substations."[777] Mr. Coppola opined that despite the detailed discussion of the projects in Mr. Robinson's testimony, DTE has not sufficiently justified this expenditure by demonstrating an improvement in reliability and a net benefit to customers.[778]

In rebuttal, Mr. Robinson reiterated his direct testimony, emphasizing that substation outages can affect large numbers of customers for extended periods. He further explained that the substation risk investments "are necessary to provide service for approximately 32,500 customers and are not aimed at reliability improvement projects that address outages from weather, trees and overhead equipment failures."[779] He further noted that undertaking a BCA for a substation that has already failed, like McGraw, would not provide any useful information.[780]

Staff witness Boutet also disagreed with Mr. Coppola's recommendation, stating that by prioritizing substation repairs at facilities where power cannot be restored using

[777] 4 Tr 3450.
[778] 4 Tr 3450-3451.
[779] 4 Tr 2047.
[780] 4 Tr 2048.

DTE's mobile fleet was reasonable approach, because a substation that cannot depend on a mobile fleet asset for service restoration is more likely to have an extended outage.[781]

DTE did not address this issue in its initial brief. In its reply brief, the Company faults the Attorney General for failing to address the merits of the specific projects and "merely claiming that the Company's evidence is 'insufficient.'"[782] DTE then reiterates Mr. Robinson's direct and rebuttal testimony, emphasizing that undertaking a BCA after a substation failure, such as is the case with the McGraw substation, would not provide any useful conclusions.[783] Staff relies on Mr. Robinson's testimony and rebuttal, as well as the rebuttal by Mr. Boutet.

The Attorney General maintains that the Company provided only "general" and "unquantified" claims regarding the project, quoting Mr. Robinson's testimony regarding the significant damage that can occur in a substation event, describing it as "unhelpful and vague."[784] She also responds to Mr. Robinson's criticism of her discovery requests on substation outages, countering that the intent of her question was clear.[785]

This PFD finds that the Attorney General's proposed disallowances for Substation Risk projects should be rejected. While the PFD agrees that many, if not most, programs that are designed to upgrade or replace equipment should be supported with a BCA, Substation Risk projects should not fall into that category, given that: (1) the program is designed to replace equipment that has already failed or is at imminent risk of doing so; and (2) a damaged or failed substation could be catastrophic and affect significant

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[781] 5 Tr 5154-5155.
[782] DTE brief, 45.
[783] DTE brief, 46.
[784] Attorney General brief, 39.
[785] Attorney General brief, 39-40.

numbers of customers who are on circuits that are served by the affected substation. As such, this PFD agrees with DTE and Staff that the Company's planning, justification, and costs for these projects are reasonable and prudent.

b. Mobile Fleet

Mr. Robinson described the Mobile Fleet program, testifying that the program "includes investments to expand the Company's fleet of mobile generation . . . used to quickly restore temporary power to customers during major events such as substation failures and to support customers during planned construction work when field crews must deenergize electric equipment for safety reasons."[786] He explained that the fleet includes, among other things, portable generators, switchgear, portable substations, portable poles, and energy storage trailers.[787] Mr. Robinson is a continuation of the program that was approved in the last rate case, and he described each of the specific projects included in this case.[788]

Mr. Coppola testified that he reviewed the list of projects and requested a BCA for any projects costing $3 million or more. He noted that the Company provided a list of four items for purchase, three of which total $1.5 million.[789] The fourth item is a portable substation costing $5.5 million. Mr. Coppola further testified that DTE did not provide a BCA for the portable substation, and when asked for information about utilization of mobile equipment, DTE responded that it did not track usage of mobile assets.[790]

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[786] 4 Tr 2022.
[787] Id.
[788] 4 Tr 2024-2027.
[789] 4 Tr 3452.
[790] Id.

Mr. Coppola opined that the lack of a BCA or relevant information on equipment usage made justification of such a costly item difficult, acknowledging that such equipment may serve to reduce outage duration and expedite repairs. He nevertheless recommended that the $5.5 million cost for the portable substation be disallowed.[791]

In rebuttal, Mr. Robinson disagreed, reiterating that the program provides short- to medium-term solutions for major outages and well as for times when DTE is undertaking planned work on its system.[792] Again referencing the McGraw substation, Mr. Robinson explained that the Company's mobile fleet serves approximately 1,400 customers while repairs are underway.[793] Mr. Robinson further explained that, as provided in Exhibit AG-6, the $5.5 million is not for the purchase of a new substation, but for "construction of five different sites geographically spread throughout the Company's service territory, to support faster deployment when needed. Each site is designed to accommodate up to three 49,000-pound portable substations with oil containment on a concrete slab and will supply auxiliary power used to maintain essential systems[.]" Lastly, Mr. Robinson stated that DTE's mobile fleet provides substantial and demonstrable benefits to customers in avoiding or reducing the duration of outages, such that a formal BCA should not be required.[794]

In briefing, the parties rely on their respective witnesses' testimony. The Attorney General reiterates that DTE failed to provide information on equipment usage or benefits, thus failing to justify the project expense.[795] The Attorney General argues that in

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[791] Id.
[792] 4 Tr 2050.
[793] Id.
[794] 4 Tr 2052.
[795] Attorney General brief, 43.

discovery, it was determined that DTE owns 14 portable substations, but beyond their locations, no additional information was provided. The Attorney General contends that if the mobile substations are being used routinely, then permanent storage locations should not be needed. If these items are not being used routinely, then she questions why portable substations or storage locations are needed at all.[796]

This PFD finds that the Attorney General's disallowance should be rejected. DTE's mobile fleet appears to be standard utility equipment used in both emergent situations and to avoid outages while the Company is repairing or replacing equipment. In addition, it is apparent from Mr. Coppola's testimony that he assumed that DTE was purchasing equipment, rather than developing permanent locations for equipment storage, which provide benefits in terms of more rapid deployment and less wear and tear on mobile assets.

7. Small Wire Replacement Project

Mr. Robinson discussed the Company's small wire replacement program, a new program for 2026, which focuses on some of the oldest portions of DTE's 4.8kV system, with some of the highest safety and reliability risks. Mr. Robinson noted that the program was created in response to the Liberty Audit's recommendation that the Company expand mitigation of wire down events to include proactive measures.[797] Mr. Robinson testified that the Company requests $10 million in test year capital expenditures to target 5-20 miles of small wires in the first year.

[796] Id. at 44.
[797] 4 Tr 1948.

Mr. Boutet testified that Staff supports the program for the safety and reliability benefits that Mr. Robinson described, and it supports the proposed investment amount of $10 million. In addition, Mr. Boutet recommended that if DTE intends to continue the program, the Company should provide analyses in future rate cases of various program metrics and lessons learned, including program scalability and costs per mile.[798]

Noting that no party object the program, this PFD finds that the requested spend amount should be approved, and that the Company should provide additional analysis of the program's costs and effectiveness in future rate cases, as sufficient information becomes available. This PFD also finds that, given the undisputed safety benefits, this program should be included in the IRM.

8. Technology and Automation

Mr. Rademacher provided an extensive review of the Company's distribution technology and automation program, explaining that investments in this program can be grouped into two main categories: (1) Grid Automation, including sensors, switches, and reclosers; and (2) Operational Technology.

Mr. Rademacher testified that DTE invested $160.4 million in 2023, $337.5 million in the 2024-2025 bridge period, and projects spend of $229.1 million in the test year in Technology and Automation.[799] Although several parties had issues concerning proposed investments in the distribution automation subprogram (i.e., reclosers) in particular, other concerns were also raised and are addressed below.

a. Conservation Voltage Reduction/VoltVar Optimization (Sched B5.4. p. 14, line 2.

[798] 5 Tr 5145-5146.
[799] 3 Tr 751; Exhibit A-12, Schedule B5.4, p.1.

Mr. Rademacher described the CVR/VVO program in his direct testimony:

> The CVR/VVO Program involves replacing end of life pole top capacitor controls with modern SCADA enabled controls that include sensors and asset health measurement. It also entails upgrades to selected substation Load Tap Changer (LTC) Controllers to coordinate with the pole top devices through the ADMS CVR/VVO control capabilities. ADMS CVR/VVO allows for pole top and LTC data to be analyzed in real time with a circuit model that computes voltage changes every few minutes and adjusts the device controls dynamically for each circuit to provide the optimal configuration as opposed to each device operating independently.[800]

As shown in Exhibit A-12, Schedule B5.4, p. 14, DTE invested $2.02 million in 2023, and projects investments of $2.519 million in 2024, $2.90 million in 2025, and $10.1 million in the test year.

Staff witness Shi did not raise any concerns about the reasonableness of the CVR/VVO program generally, noting that the Company intends to upgrade 22 circuits in 2025, including replacing 50 capacitors. However, in 2026, DTE plans to upgrade 40 additional circuits including 70-80 capacitors. Ms. Shi explained that Staff questions the feasibility of ramping up the program to $10 million in 2026, “considering that as of May 2025, only $426,000 had been expended,” as shown in Exhibit S-10.1. She further observed that the amount spent in 2025 to date appeared consistent with levels in 2023 and 2024.[801]

Based on Staff’s concerns about the Company’s ability to execute the expanded program in the test year, Ms. Shi calculated an adjustment of $7.123 million for the test year based on 2025 projected spend of $2.9 million, adjusted for inflation.[802]

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[800] 3 Tr 782.
[801] 5 Tr 4998.
[802] Id. at 4999.

In rebuttal, Mr. Rademacher stated that Staff appears to assume that DTE's previous investment levels were constrained by execution capacity or resource limitations. According to him, this was not the case, explaining that the lower investment levels from 2023-2025 were related to the Company's intention to complete ADMS implementation before moving forward with CVR/VVO. He added that the scope of work planned for the test year is in line "with typical expectations for projects of similar scale and investment level."[803] Mr. Rademacher concluded that the $7.1 million reduction Staff proposes would significantly impede the Company's progress, delaying energy efficiency and optimization of customer voltage.[804]

In briefing, DTE relies on Mr. Rademacher's testimony, emphasizing that the Company's previous, lower investment levels in CVR/VVO were intentional to allow for the completion of ADMS installation.[805]

Staff responds that it agrees with this explanation for previous spend levels, but it maintains that DTE has not provided specific information about project timelines or a work schedule indicating how the Company intends to increase the scope of work from 2023-2025 levels to what it proposes in 2026.[806]

A review of Exhibit 10.1, p. 139 shows that DTE admitted uncertainty about its work plan for CVR/VVO. Specifically, Staff asked about the total number of circuits and capacitors the Company planned to install in 2026, along with the unit cost of the capacitors. DTE responded that "[t]he exact number of capacitors that will be installed is

[803] 3 Tr 937.
[804] 3 Tr 938.
[805] DTE brief, 78.
[806] Staff brief, 31.

not known as the circuits are still going through engineering." When asked about the reasons for the significant increase in spending for 2026, the Company simply stated that "the program is ramping execution to install capacitors on 70 circuits," a vague, if not entirely circular answer. As such, this PFD agrees with Staff adjustment of $7.1 million to the CVR/VVO program. If DTE installs more units in 2026, it may request recovery in a future rate case.

b. Distribution Automation (Reclosers)

Mr. Rademacher testified regarding DTE's investments in DA, which involves the installation of reclosers on distribution circuits. According to him:

> The Distribution Automation Program within Grid Automation uses digital field sensors and switches along with advanced control and communication technologies to automate or remotely control feeder switching, monitor voltage and equipment health, and manage voltage and reactive power. Without remote switches, the alternative option is for a crew to be dispatched to manually open or close a switch. In addition to the field resources cost, this results in a delay in operating the switch, which could cause or extend outages as well as other grid impacts.[807]

In addition to the purported reliability benefits of reclosers, Mr. Rademacher discussed safety benefits, explaining that:

> Currently, when a ground alarm appears on a circuit, a substation operator is dispatched to the substation and manually identifies which circuit has a ground, then a field crew is sent to locate the ground and isolate. With the ability to automatically identify this condition, the potential hazard can be detected and deenergized much more quickly and efficiently through automated isolation, quickly eliminating the risk associated with the downed wire. Addressing these potential hazards automatically not only reduces the potential safety risk sooner but enhances restoration efficiency by allowing resources previously used to isolate energized wiredowns to instead be directed to restoration activities.[808]

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[807] 3 Tr 757.
[808] 3 Tr 759.

Turning to the Liberty Audit findings on the DA program, Mr. Rademacher testified that the Audit recognized and supported DTE's efforts at improving grid reliability and safety, but he noted that the Audit's recommendation for timing the deployment of DA did not comport with DTE's distribution plan filed in Case No. U-20147. In that respect, Mr. Rademacher stated that DTE disagreed with the Audit to slow down grid automation, because it would delay the benefits of safety and reliability resulting from DA. He added that the Company would continue to refine its planning for DA to prioritize circuits where benefits are expected to be greatest.[809]

Addressing the Case No. U-21534 order, Mr. Rademacher observed that the Commission approved most of the Company's revenue request for DA, indicating that it was anticipating a BCA from DTE, which was provided in the instant proceeding and discussed above.[810] Mr. Rademacher presented Table 2 at 3 Tr 763, which shows the number of circuits and reclosers installed and planned from 2023 to 2026, and he discussed the benefits of the DA program so far, including: (1) improved safety in wiredown events; (2) increased reliability in terms of fewer outages and shorter outage durations; and (3) improved operating efficiencies resulting from better system monitoring and control.[811] Going forward, Mr. Rademacher testified that DTE:

> . . . expects to dedicate approximately one third of the total capital investment allotted to the Distribution Automation program, through both rate case base rate investment approval and the IRM mechanism explained more fully by Witness Willis, toward the installation of start of circuit safety reclosers. If the Company's request is approved, DTE Electric would invest approximately $25 million in 2025, $50 million in 2026, and $55 million in 2027, on safety reclosers through a combination of the base rate approvals and the IRM mechanism. This plan would result in the majority of 4.8 kV

[809] 3 Tr 761.
[810] 3 Tr 761-762.
[811] 3 Tr 763-764.

> overhead load carrying circuits completed with safety recloser installations in early 2028.[812]

Staff witness Shi reviewed DTE's historical expenditures on DA starting with $10,000 invested in 2020, increasing to $27.0 million in 2023, decreasing to $19.5 million in 2024, and projected to increase to $105.625 million and $115.625 million in 2025 and 2026 respectively. She noted that in the first four months of 2025, DTE spent $7.516 million on the DA program.[813]

Ms. Shi expressed that Staff supports the DA program, but she also noted in its order on the Liberty Audit, which recommended that DTE slow the deployment of DA, the Commission stated that in its next distribution plan, DTE should:

> . . . describe planned timing for Viper recloser installation on the 4.8kV system for safety at the substation exits and for reliability beyond the substation exits and include an assessment that compares tree trimming and other alternative measures for providing safe, reliable service so that the prioritization of expenditures to improve reliability cost effectively may be more clearly discerned.[814]

Observing that the order in DTE's last rate case, Case No. U-21534, was issued before the order in the Liberty Audit docket, and reiterating that DTE has only spent $7.5 million of the $105 million approved in the rate case for 2025, Ms. Shi opined that the implementation pace of the DA program should be carefully managed and that the program budget forecast should be aligned with the Company's actual spending in 2025.[815]

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[812] 3 Tr 764.
[813] 5 Tr 4999.
[814] Id. quoting June 12. 2025 order in Case No. U-21305, p. 36.
[815] 5 Tr 5000.

Consistent with the above, Ms. Shi testified that Staff projects $22.6 million in DA investment in 2025, assuming equal spending for the remainder of the year, resulting in a disallowance of $83,077,000 for 2025. For the test year, Staff applied inflation and based on 2025 investments, projected total spending of $23,147,777, resulting in a disallowance of $92,477,223.[816]

MNAG witness Stephens testified that because public safety is of paramount importance, he did not oppose the deployment of reclosers for safety purposes. However, he pointed out that costs and reliability benefits of DA vary considerably by circuit, thus, the cost-effectiveness of DA similarly varies widely.[817]

Mr. Stephens explained how reclosers can operate to improve reliability, by using DA, rather than utility workers, to reroute energy around a fault so that the number of customers affected is minimized. However, he observed that reclosers do not always operate correctly, and they function best, and most cost-effectively, when tie lines between circuits have already been constructed and only the recloser need be installed.[818] He added that the benefits of DA also depend on the number of customers on a circuit, and lastly he pointed out that DA "is a solution that addresses the symptoms of faults . . . not the root causes of faults (such as vegetation contact). It can be more appropriate, and more cost-effective, to reduce the frequency of faults through routine, mandatory maintenance, rather than deploy distribution automation to isolate the impact of faults (service interruptions) to fewer customers when faults occur."[819]

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[816] Id.
[817] 5 Tr 4485.
[818] 5 Tr 4486.
[819] 5 Tr 4487.

Mr. Stephens next discussed the significant increase in proposed DA spend between 2026 and 2029, noting that the amounts are far in excess of the sums needed to address safety, and despite the fact that DTE has yet to fully evaluate the benefits of the DA the Company has already deployed.[820] He added that he concurred with the Liberty Audit that: (1) DA would not be cost effective if the causes of interruption were minimized through vegetation management and pole top inspections; (2) the benefits of DA do not warrant the investment levels that DTE is proposing; and (3) DTE's planned spending on DA, as set forth in the Company's distribution grid plan, should be reduced by $600 million as more data is collected.[821]

Again, expressing general agreement with the Audit, Mr. Stephens opined that DA expenditures should be reduced even more than suggested by the Audit, so that only the costs of safety reclosers are included. Noting that the capital DTE will have spent through 2025 ($202.6 million) and the DA investment amount already approved for 2026 ($24 million), DTE has sufficient funding to install DA on 1,991 4.8kV circuits where safety is a concern. Accordingly, Mr. Stevens recommended that the amount approved for DA in 2025 and 2026 be limited to $227 million, and that no additional amounts be authorized until the Company catches up on maintenance and assesses the reliability improvements on circuits where DA has been implemented.[822] This would result in a 2027-2029 IRM disallowance of $735 million, and a reduction of $112 million for the test year.

Both Mr. Stephens and Mr. Alvarez addressed the BCA that the Company conducted for DA. Mr. Stephens testified that the analysis includes circuits where tree

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[820] 5 Tr 4489.
[821] 5 Tr 4489-4490.
[822] 5 Tr 4490-4991

trimming and PTMM have not occurred, thereby skewing the BCA results to show that DA is more cost-effective on many circuits than it actually is.[823]

Mr. Alvarez criticized cost assumptions in the BCA, pointing out that the analysis assumes that only 50% of circuits will require capacity upgrades to circuit ties, and that only 34 new ties will be needed from 2026-2029. According to him, capacity upgrades and new ties can cost several hundred thousand dollars per mile, but the model assumes that a limited amount of this work will be required. Mr. Alvarez echoed Mr. Stephens' concern that the BCA included circuits that have not undergone inspection or vegetation clearing, thereby lowering baseline reliability and inflating the reliability benefits of DA.[824] He pointed to Mr. Stephens testimony that all but seven of the 1,189 circuits that had a BCR greater than 1 in DTE's analysis were on the list of circuits where vegetation management or PTMM had been deferred.[825]

Mr. Fitzhenry also addressed the BCA for DA, noting that the Liberty Audit recommended that DA implementation be limited until better information about the contribution of reclosers to reliability is developed. He added that the Audit "highlights that the reliability benefits of reclosers are difficult to isolate from other reliability-improving measures, such as enhanced vegetation management and PTMM work."[826] And Mr. Fitzhenry pointed out that the benefits of DA will diminish over time as fewer outages occur due to other interventions such as PTMM and tree trimming. Mr. Fitzhenry therefore

[823] 5 Tr 4991.
[824] 5 Tr 4636-4637.
[825] 5 Tr 4637.
[826] 4 Tr 3364.

recommended that DA investments be reduced to 2025 levels, adjusted for inflation, an $8.5 million disallowance in 2026 and a reduction of $400 million from 2027-2029.

CEO witness Volkman described the part of the U-21534 order addressing DA, as well as the Liberty Audit findings, highlighting the Audit's recommendation that the Company should complete the installation of safety reclosers "as soon as possible," as well as the recommendation that DTE slow the implementation of reliability reclosers until reliability benefits can be better understood.[827]

Next, Mr. Volkman recapped the Company's revenue recovery requests for DA in the bridge and test periods and beyond as part of the IRM. As discussed more detail below, Mr. Volkman testified that DTE's request for DA cost recovery in the IRM was unclear as to the amount requested, how it corresponded with the BCA, or how the funds would be used.[828]

Quoting Mr. Rademacher's testimony that approximately one third of DA capital would be invested in safety reclosers, ($25 million in 2025, $50 million in 2026, and $55 million in 2027), resulting in the majority of safety reclosers installed by 2028, Mr. Volkman pointed out that DTE's plan is contrary to the Liberty Audit recommendation, as well as the Company's stated priorities, and the BCA, which assumes the benefits of safety outweigh the costs.[829] As a result of his assessment, Mr. Volkman recommended that DTE complete the deployment of safety reclosers in 2026.

Finally, as was the case with PTMM, Mr. Volkman raised concerns about future cost increases for labor and equipment for the DA program that were not accounted for

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[827] 4 Tr 3659, quoting Liberty Audit Part II, p. 84.
[828] 4 Tr 3661.
[829] 4 Tr 3662-3663.

in the BCA, recommending that the BCA include a sensitivity analysis that reflects future cost increases for conductors and reclosers.[830]

Lastly, Ann Arbor witness Stultz also testified that she does not support recovery of DA investments for reliability and that the amount proposed for reliability reclosers in the test year ($65.625 million) should be disallowed, along with $83.37 million in the bridge period, based on Mr. Rademacher's indication that one third of DA investments would be used for safety reclosers.[831]

Turning to the BCA that the Company provided to support the DA program, Dr. Stultz observed that the analysis was based on outage information from 2019-2023, and that future outages will be the same as past outages.[832] She question this approach because it failed to take into account the last two years of the tree-trimming surge and because it failed to take into account reliability benefits of the PTMM in forecasting future reliability benefits of DA. As a result, she concluded that the benefits of DA are likely overstated in the BCA.[833]

Dr. Stultz also referenced the Liberty Audit finding that DA would not be cost effective if the causes of outages were reduced, citing that Audit's finding the DA would only improve reliability in the short term. Thus, she concluded that investing ratepayer funds into short-term solutions such as DA was imprudent, and she recommended that DTE focus more on addressing the root causes of outages including tree trimming and PTMM.[834]

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[830] 4 Tr 3663.
[831] 4 Tr 3725.
[832] 4 Tr 3726, referencing Exhibit A-28, Schedule R3, p. 63.
[833] 4 Tr 3727-3728.
[834] 4 Tr 3728-3729.

Mr. Rademacher provided extensive rebuttal to the positions taken by the other parties. In response to Staff's disallowance based on limited execution of the DA program to date, Mr. Rademacher pointed out that the Staff's information is based on a narrow time frame and assumes that spending and execution occur equally in every month (as also discussed above).[835] Mr. Rademacher explained that Staff's calculation results in three months of DA spend of $7.5 million, or $22.5 million annually. However, more recent information, updated to the end of July, 2025, shows cumulative investment at the end of July of $25.3 million.[836] Mr. Rademacher recommended that if any disallowance were made, it should be based on DTE's actual seven-month investment, or acknowledge the Company's ramp-up plan and reapprove the full $105.6 million recommended in Case No. U-21534.[837]

As for Staff's concerns about DA implementation in 2026, Mr. Rademacher presented Figure 2 at 3 Tr 909, which depicts the average number of DA installation crews per month in 2025, which the Company projects to continue to increase into 2026.

Responding to Staff and Intervenor concerns about the findings of the Liberty Audit with respect DA, Mr. Rademacher pointed out that the Audit, Part II, p. 94, recommended that the implementation of reliability reclosers in the later years be tied to better information on the reliability benefits of reclosers, while still recommending that the Company accelerate the implementation of safety reclosers. He further observed that in the order addressing the Audit, the Commission did not specifically recommend slowing down the DA program. And, despite the timing of the Audit, the order in Case No. U-

[835] 3 Tr 904.
[836] 3 Tr 906.
[837] 3 Tr 906; Exhibit A-53, Schedule TT1.

21305, and the Company's filing in this case, in the U-21534 order, issued in January 2025, the Commission indicated that it was looking forward to the results of the BCA that was in progress at that time, and that was presented here.[838]

Mr. Rademacher discussed the results of the BCA, which supports investment in reliability DA, as well as improved reliability (SAIDI and SAIFI) that he attributed to the reliability recloser program.[839] He explained that while DTE agrees that improved safety benefits are important, the Company is also focused on improved reliability, which also has safety aspects for customers that rely on medical equipment, as well as first responders. As such, he opined that DTE's "combined" approach to safety and reliability in the DA program is reasonable.[840]

Responding to intervenor concerns that DA does not address root causes of outages, Mr. Rademacher reiterated that DA is additional to tree trimming and PTMM and that DA is part of a number of investments intended to address safety and reliability in both the long and short term. He explained that the relationship among the different programs was considered, and the PTMM and DA BCAs were not developed independently.[841]

The parties' briefing generally tracks the testimony of their witnesses. DTE emphasizes that in its order in Case No. U-21305, the Commission did not call for a slow-down in the DA program; it only directs that the Company provide more information in its next distribution plan case on DA and a comparison to alternatives such as tree trimming

[838] 3 Tr 912.
[839] 3 Tr 914.
[840] 3 Tr 916.
[841] 3 Tr 919.

and PTMM. DTE points to the BCA presented in this case, which the Company argues fully supports the level of investment it proposes, and it indicates that additional analysis in the next distribution plan will enhance planning going forward. However, the fact that the Commission requests a more refined analysis does not conflict with the need to continue the DA program in the interim.[842]

Staff's brief recaps Ms. Shi's testimony and recommendations. In response to Mr. Rademacher's rebuttal, Staff states that it is willing to update 2025 spend to include additional DA spending through August, as Mr. Rademacher suggested. Staff therefore modified its 2025 adjustment to a disallowance of $62,253,571. Using the 2025 revised basis, and adding inflation, Staff now recommends a disallowance of $72.0 million from DTE's requested DA investments in the test year, which does not affect the $24.4 million included in the IRM for 2026.[843]

MNSC argues that DTE's significant investment in DA prioritizes reliability (which is supported by a flawed BCA) over safety and the requested increase should be rejected. MNSC reiterates that the Liberty Audit expressly recommended a slower pace for DA investments, because reliability improvements have not been demonstrated, noting that the Commission also pointed to the importance of tree trimming and other more economical alternatives to DA in providing safe and reliable electric service in the U-21305 order.[844]

Turning to the BCA, MNSC emphasizes that not only was the analysis fundamentally flawed, for the reasons discussed by Mr. Alvarez and Mr. Stephens, but it

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[842] DTE brief, 73-74.
[843] Staff brief, 34.
[844] MNSC brief, 91-95.

also did not evaluate alternatives to DA, such as maintenance, that might prove more cost-effective.[845]

MNSC contends that DTE has used safety benefits to justify DA for years, pointing to the GPM, the Company's 2023 grid plan, and its presentation in Case No. U-21534, noting that the Commission found the safety benefits of DA to be persuasive in that proceeding. However, despite the Company's past justifications for the deployment of safety-related reclosers, "DTEE has taken an inverse approach to prioritizing its DA capital spending program, where only about one-third of DA spending for safety."[846]

Lastly, MNSC emphasizes that DTE has failed to show that DA will in fact improve reliability by not evaluating CMI before and after the installation of reclosers on circuits where they have been deployed.[847]

ABATE, Ann Arbor and the CEO repeat their respective criticisms of the Company's DA spending plan, arguing that: (1) DTE's plan is not sufficiently focused on safety, despite the recommendations of the Liberty Audit; (2) DTE's BCA was deficient in several ways as outlined by intervenor witnesses; and (3) DTE should focus much more on outage avoidance through PTMM and tree trimming, rather than implementing costly solutions like DA that will only improve reliability in the short run.[848]

This PFD agrees with Staff and intervenors that, going forward, DTE's DA program should be limited to investments for safety reclosers and that additional investments in DA for reliability purposes should await a more complete and detailed analysis of benefits,

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[845] MNSC brief, 97-101.
[846] MNSC brief, 105.
[847] MNSC brief, 111-112.
[848] ABATE brief, 20-22; Ann Arbor brief, 7-11; CEO brief, 18-23.

preferably in a way that takes into account the effects of other measures like catching up on delayed or deferred maintenance. Numerous parties correctly observed that DA does not prevent outages; it simply mitigates them, whereas efforts like tree trimming and PTMM can prevent outages, making expensive DA investments unnecessary. As MNSC contends:

> At bottom, the Company's position is that the Commission should approve its proposed level of spending for DA deployment aimed at improving reliability because it is likely to generate interim reliability benefits while the Company catches up on longer-term distribution system maintenance. This position is unsound where resources were limited, as they are for DTEE residential customers, who carry the cost of these investments. The Company's approach ensures a double-hit to residential customers, who pay both the high cost of reliability-based DA and they pay the full cost of necessary ongoing maintenance. The best approach is proper maintenance – in an environment where the utility kept up with trimming and line repairs, automation is not cost effective to improve reliability.

In assessing the entire record on this issue, this PFD finds two things particularly concerning. First, as MNSC argues, DTE has repeatedly and persuasively focused on the safety benefits of DA, but it now proposes to take a more relaxed approach to this serious issue by planning to invest only one-third of its allotted funds in safety DA, while the rest is dedicated to reliability reclosers. Second, despite the fact that outage prevention through inspection and maintenance activities is undisputed as the preferred approach for improving reliability, as discussed *passim*, DTE is now seeking to increase its tree trimming cycle time rather than reduce it as recommended in the Audit.

It is acknowledged that every dollar spent on O&M expense, like tree trimming and inspections, increases the revenue requirement by the same amount, whereas a dollar spent on a capitalized investment does not. In the long run, however, capital investments, like DA, are far more costly to ratepayers. Given the significant and valid concerns about

energy affordability for DTE's customers, an appropriate balance must be struck between capital and O&M, and this PFD finds that the substantial investments the Company proposes for reliability DA do not achieve that objective.

Turning to the appropriate adjustments for 2025 and 2026, this PFD does not find that reliability DA investments made to date should be disallowed, as some parties seem to suggest. Indeed, the circuits on which the reliability reclosers are installed may provide important data for future analyses. However, going forward, DTE should be focusing exclusively (or nearly exclusively) on safety-related DA, as the Liberty Audit recommended.

Further, this PFD agrees with Staff that DTE's ability to execute this program at the level forecasted is in question, even considering the update numbers provided by the Company in rebuttal. The fact that DTE suggested a modification to Staff's disallowance is telling, and it indicates that the Company may also have doubts about its ability to deploy the number of reclosers it forecasted in its plan. Therefore, this PFD finds that Staff's recommended disallowances of $62,253,571 for 2025 and $72.0 million for 2026 should be adopted.

c. Line Sensors

Mr. Rademacher explained that line sensors are equipment "used to monitor the real time status of the distribution system and provide critical information to field personnel and system control room operators to help them better monitor and manage the grid."[849] Discussing the scope of the program, Mr. Rademacher testified:

[849] 3 Tr 785.

> This program includes the installation of overhead system sensors used to detect outages and faults on the overhead and underground lines and send the data directly to the ADMS to speed restoration. These sensors also monitor power quality and fault data needed for real time load transfer analysis, fault locating, and system status. It also includes the installation of Underground Residential Distribution sensors for use in underground areas to quickly direct field crews to fault underground sections to improve isolation and restoration times. This program will also include a technology demonstration of new sensors intended to help monitor the system for broken pole and wiredowns, allowing dispatchers to better locate and differentiate between energized and deenergized wiredowns as well as downed electrical lines versus joint use wires.[850]

Describing these sensors as the "eyes and ears of the grid, Mr. Rademacher discussed the benefits of the sensor program, focusing particularly on faster restoration after a fault.[851] Mr. Rademacher recapped the history of the program since 2023, and he testified that DTE plans to install approximately 450 overhead sensors and 800 underground sensors in 2025, and an additional 450 overheard sensors and 1,100 underground sensors in 2026.[852] As shown in Exhibit A-12, Schedule B5.4, capital expenditures for the program are $3.5 million in 2025 and $2.0 million in 2026.

Ms. Shi testified that, as shown in Exhibit S-10.2, DTE had spent $153,000 on line sensors in the first four months of 2025. Acknowledging the significant value of the program, Ms. Shi nevertheless expressed Staff's concern that only a small fraction of the projected investment was spent by May 2025, raising a question whether DTE prioritized other work or did not have sufficient resources to execute the project.[853]

Assuming that the current pace of installation will continue, Ms. Shi used the 2024 unit cost for the sensors and calculated a 2025 investment of $899,757, a reduction of

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[850] 3 Tr 786.
[851] 3 Tr 786-787.
[852] 3 Tr 787-788.
[853] 5 Tr 5001-5002.

$2.600 million and a 2026 cost of $1,145,377, recommending a disallowance of $845,623.[854]

In rebuttal testimony, Mr. Rademacher disagreed with the reductions proposed by Ms. Shi, maintaining that that's Staff's calculation, based on extrapolation of four months of spending, "overlooks several key factors like seasonal construction patterns, project management dynamics which follow a non-linear timeline and vary throughout the year and, finally, installation and purchasing cadence which does not align with a simple monthly average."[855] To illustrate his point, Mr. Rademacher pointed to Exhibit A-53, Schedule TT13, which shows that overhead line sensors that were purchased in 2023 for installation in 2025, and DTE's plan to bulk-purchase sensors in 2025 for installation in 2026, which "demonstrate[es] a forward-spending non-linear approach to budgeting."[856]

Mr. Rademacher also expressed concerns that Staff did not recognize that there are different unit costs for overhead versus underground sensors, adding that DTE is on track to complete program spending, stating that as of July 31, 2025, the Company had spent $259,000 to install 295 overhead sensors and projects to spend an additional $241,000 to install 156 sensors by the end of the year. This, coupled with the plan to purchase $2.0 million in materials by the end of the year, demonstrates that the investment will be made as projected.[857]

DTE's briefing does not appear to address this disallowance. Staff argues that although Mr. Rademacher addressed Staff's recommendation, including DTE's plan to

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[854] 5 Tr 5002.
[855] 3 Tr 960.
[856] 3 Tr 961.
[857] 3 Tr 961.

purchase sensors in 2025 for installation in 2026, the Company did not provide a purchase order or any other documentation to support this plan. Absent this support, Staff maintains that its disallowance should be adopted.

This PFD recommends that the Commission adopt Staff's recommended disallowances for 2025 and 2026, because DTE failed to brief the issue. The case instructions for this proceeding attached to the scheduling memo (Docket Entry # 0067, Attachment A, page 4, no. 4) clearly state:

> The parties should expect to include the following in your briefs: (1) a table of contents; (2) a summary of position on each issue; (3) a description of the entire record relating to each issue briefed (i.e., pinpoint transcript cites to each witness testifying on that issue and exhibit/schedule and line numbers pertinent to the issue). For each specific topic covered the company shall provide citations to the record for all witnesses testifying on that topic, as well as all relevant exhibits, at the beginning of the narrative on the topic.

DTE's failure to address this specific topic in briefing leaves no choice but to adopt Staff's disallowances of $2.600 million in 2025 and $845,623 in the test year.

d. Customer Power Status Visibility

As shown in Exhibit A-12, Schedule B5.4, p. 14, line 13, DTE projects capital expenditures for the Customer Power Status Visibility (CPSV) program of $55,967,000 in the 24-month bridge period ($43,967,000 in 2024, and $12,000,000 in 2025) and $12.0 million in the 2026 test year. Mr. Rademacher described the program as a collection of projects that expand the Company's optimization of its Advanced Metering Infrastructure (AMI) and will entail the replacement and additional installation of Field Area Routers (FARs) to allow AMI meter signals to reach the Company.[858]

[858] 3 Tr 819-821.

Staff witness Hansen recommended a disallowance of $1,880,000 in the 2025 bridge period and $6,000,000 in the test year.[859] He explained that DTE indicated in audit that it projects to spend $1,000,000 for labor and $11,000,000 for material in 2025 to purchase and install 1,200 FARs at a unit cost of $7,600.[860] Mr. Hansen disputed this projection because the unit cost multiplied by the number of units equals $9,120,000, which is $1,880,000 less than what the Company is requesting for materials.[861] Next, Mr. Hansen noted that for 2026, the Company projects to spend the same amounts for labor and material as in 2025 but will be purchasing only 600 FARs, half as many as in 2025.[862] He therefore recommended that the 2026 projected costs be cut in half.[863]

DTE did not respond to Staff's proposed CPSV disallowance in rebuttal testimony or initial briefing. In its brief, Staff argues that the Commission should disallow the expenditures identified by Mr. Hansen, noting that no party rebutted Staff's position.[864]

In its reply brief, DTE mentions Staff's proposed disallowance but otherwise fails to provide any argument in opposition other than referencing Mr. Rademacher's rebuttal testimony, which is devoid of any mention of the CPSV program.[865]

This PFD agrees with Staff that DTE's projected costs for the CPSV program are not aligned with the Company's projected purchase and installation of FARs in the bridge period and test year, noting that Staff's calculations and conclusions in this regard were

[859] 5 Tr 5171.
[860] 5 Tr 5172, citing Exhibit S-22.0, pp. 7, 13.
[861] 5 Tr 5172, citing Exhibit S-22.2.
[862] 5 Tr 5172, citing Exhibit S-22.0, p. 14.
[863] 5 Tr 5172.
[864] Staff brief, 37-38.
[865] DTE reply, 60-61.

left unrebutted. As a result, the Commission should disallow capital expenditures of $1,880,000 in the bridge period and $6.0 million in the test year.

e. SCADA Historian

According to Exhibit A-23, Schedule M7, p. 48:

> The SCADA historian is currently funded on a yearly basis and by doing multiyear funding, prices can be locked in. The SCADA Historian is an essential portion of the SCADA software ecosystem, providing long term storage and retrieval for engineers and analysts and the baseline for loading and voltage statistics and analysis including system performance information and telemetry status.

As shown in Exhibit A-12, Schedule B5.4, p. 14, line 14, DTE projects an expenditure of $5.0 million in the test year to purchase a multi-year software license for the program.

Ms. Shi testified that when asked in discovery for a "justification" for the license, the Company responded with a description of the program and an explanation that there is no unit cost or itemization, since the expenditure is for a single item, categorized as "material" without labor or hardware costs.[866] Ms. Shi testified that Staff recommends a 50% disallowance of the cost until DTE submits an invoice or other document substantiating the expenditure.[867]

In rebuttal, Mr. Rademacher objected to Staff's recommended disallowance, testifying that the Company explained the request, adding that the vendor's name, the basis for the request and the invoice were not requested in discovery. According to him, "[t]he absence of these inquiries should not form the basis for disallowance."[868]

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[866] 5 Tr 5003; Exhibit S-10.1.
[867] 5 Tr 5003-5004.
[868] 3 Tr 952.

Mr. Rademacher stated the name of the vendor and explained that the basis for the $5.0 million cost can be found in Exhibit A-53, Schedule TT5. He noted that the 2026 expenditure for the license "is a vendor-based formula that was confidentially negotiated."[869]

The parties' briefs rely on the testimony of their respective witnesses.[870]

This PFD agrees with Staff that 50%, or $2.5 million, should be disallowed for the SCADA Historian project. A review of Confidential Exhibit A-53, Schedule TT5[871] shows that the information provided is unclear and otherwise does not support the request. While Staff could have asked for additional information in discovery, DTE also had its opportunity to provide more details as part of rebuttal. Additional amounts for the SCADA Historian can be requested in a future rate case, provided the Company submits more details on the expenditure.

f. Mobile Equipment Replacement (Exhibit A-12, Schedule B5.4, p. 14, line 38)

According to Mr. Rademacher, DTE deploys thousands of mobile devices for field workers, and these devices are replaced on a six-year cycle, with 1/6 of all devices replaced each year. He described the benefits of the program, particularly pointing to increased reliability and enhanced security of up-to-date equipment.[872]

Ms. Shi testified that, as shown in Exhibit A-23, Schedule M8, p. 161, DTE projected capital expenditures of $2.8 million in 2024, $2.8 million in 2025, and $1.4

[869] 3 Tr 953.
[870] DTE brief, 80; Staff brief, 38-39.
[871] It does not appear that there is a public version of the exhibit.
[872] 3 Tr 893.

million in 2026. However, according to Ms. Shi, other Company exhibits project $881,000 in 2024, no spending in 2025, and $3.5 million in the test year.[873]

Ms. Shi explained Staff's concern that DTE has requested funding for mobile device replacement in the past, but the Company did not expend the amounts approved. Further, Ms. Shi testified that Staff cannot see the need to replace all of the mobile devices in 2026, and as such, Staff recommends a 50% reduction in the capital expenditure request, or $1.750 million. This would also allow DTE to take advantage of technology improvements and explore more cost-effective solutions in the future.

In rebuttal, Mr. Rademacher disagreed with the disallowance, stating that "the recommendation overlooks the accumulated need created by three years of deferred replacements[,] . . . [t]he 2026 request is not an overallocation of a single year but but the first major replacement cycle after a multi-year pause[.]"[874] Mr. Rademacher explained that this equipment is critical and many of the devices have reached EOL, or are no longer receiving critical updates, leaving the Company vulnerable to cybersecurity risks.[875]

In its brief, DTE argues that Staff's disallowance ignores the need for device replacement after three years of deferral, reiterating that its request "is not an overallocation of a single year but the first major replacement cycle after a multi-year pause, addressing more than 1,900 devices that are outdated or past End-of-Life."[876]

Staff maintains its position, asserting that while it understands DTE's need to replace outmoded devices, "Staff also notes that the funds approved by the Commission

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[873] 5 Tr 5004.
[874] 3 Tr 954.
[875] 3 Tr 954-955.
[876] DTE brief, 80.

in prior years for similar mobile device replacements were not utilized for that purpose."[877] Staff reiterates that because DTE did not expend previously approve funds for mobile devices, it is unable to validate whether all of the devices need replacement in one year.[878]

This PFD agrees with Staff. The Company's argument that these devices are vital to field operations and must be updated on a regular schedule is belied by the fact that the Company deferred replacements for several years and now wishes to play catch up. The PFD therefore recommends adopting Staff's disallowance of $1.750 million in the test year.

g. Mobile Timesheets and Vegetation Management Replatform

After initially recommended adjustments to these programs, Staff reviewed DTE's rebuttal and states that it is satisfied with the requests, and it withdraws its disallowances.[879]

9. Distributed Energy Resource Management System

DTE projects capital spending for DERMS of $1.5 million in the bridge period and $2.8 million in the 2026 test year.[880] Mr. Rademacher explained that DERMS is a control system designed to manage DER at the residential, commercial, industrial, and distribution grid levels.[881] He testified that the Company is implementing a Utility DERMS that will provide broad functionality and will enable growing levels of DERs on the grid.[882] He testified about DTE's strategy for deploying DERMS:

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[877] Staff brief, 40.
[878] Id.
[879] Staff brief, 41-43.
[880] Exhibit A-12, Schedule B5.4, p. 15, line 45.
[881] 3 Tr 835.
[882] 3 Tr 836-837.

> The Company's strategy is to focus on the areas where DERMS is needed for compliance and areas where it can increase the efficiency of existing processes and systems and build interfaces or consolidate systems that currently do not work together. Under this approach, components are implemented as they are needed and at the scale that they are needed. Some of the first components that are needed are consolidation of management systems that coordinate DER and DR data as well as program participation and interface to the ADMS. This will allow current DR and DER programs to be tracked more efficiently, benefitting customers that are currently in DR, load management and DER programs, and enabling the dispatch of larger existing SCADA controlled assets in coordination with the ADMS and Market Systems to support currently implemented programs (such as implementing the requirements of FERC Order No. 841). Future phases of DERMs will focus on developing and implementing forecasting and optimization capability and automation of constraint management and Distribution System Operator (DSO)/Transmission System Operator (TSO) coordination.[883]

Mr. Rademacher testified that DTE has identified a list of requirements for framework, functionality, demand response, and integration into utility systems based on MISO compliance filings and ongoing workshops.[884] The Company's 2025 investments "will be in the DERMS software licensing, program, and configuration database to centralize DER program management, related constraints, and the tools to assign DER to system model nodes."[885] In 2026, the Company plans to implement systems components and create interfaces.[886] Mr. Rademacher opined there are risks of not proceeding with DERMS investments, which include missing compliance dates to meet MISO's implementation of FERC Order No. 2222.[887]

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[883] 3 Tr 836.
[884] 3 Tr 838.
[885] 3 Tr 838.
[886] 3 Tr 839.
[887] 3 Tr 839. Mr. Rademacher explained that FERC Order No. 2222 "seeks to better enable DER to participate in the electricity markets run by regional grid operators." 3 Tr 837, n. 27.

DTE also plans capital investments of $12.0 million in the bridge period and $5.400 million in the test year for Grid Edge Insights and New Technology, a sub-category of Grid Automation investments.[888] Mr. Rademacher testified that these investments will "consolidate the learnings from the NWA pilot projects into a consistent platform" and develop a "standardized gateway platform" that will simplify the integration of DER systems to ADMS and the future DERMS.[889] He testified that DTE has made progress on its Grid Edge Insights and New Technology projects, including 2024 investments to expand the solar and storage testbed for testing interconnection gateways and battery trailer systems. He further detailed the investments planned for 2025 and 2026 and testified that these investments will increase the Company's ability to integrate DER into grid operations and allow for more flexible DER operation.[890]

CEO witness Kenworthy identified four concerns he has with the Company's approach to its DERMS and Grid Edge Technology investments. First, he testified that the programs are designed from the utility's operational perspective to exercise control and provide visibility into DER operations, rather than from a customer-value perspective. Second, he testified that DTE's proposals lack programs to help residential and small commercial customers participate in grid management, manage their energy costs, or monetize their flexibility.[891] Third, he opined that the Company's NWA pilots and Grid Edge investments focus too narrowly on technical demonstrations rather than customer programs.[892] And fourth, he testified that the Company lacks "a comprehensive strategy

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[888] 3 Tr 799; Exhibit A-12, Schedule B5.4, p. 14, line 31.
[889] 3 Tr 799-800.
[890] 3 Tr 801-802.
[891] 4 Tr 3610.
[892] 4 Tr 3610.

to utilize these technologies for programs that provide customers with meaningful opportunities to shift usage, reduce costs, or participate in grid services markets."[893]

Mr. Kenworthy recommended that the Commission defer approval of the Company's proposed DERMS and Grid Edge Insights and New Technology expenditures until DTE files "a comprehensive business case, including a benefit-cost analysis, that draws on best practices from other states and provides an actionable plan to integrate DER into programs that deliver load flexibility, help customers manage their energy use, and reduce distribution system costs."[894] He testified that the Commission took such an approach in Consumers Energy's most recent rate case, where it conditioned the recovery of DERMS expenses on the submission of a business case with a comprehensive BCA.[895] Mr. Kenworthy further testified about the components that he believed should be included in a business case, and he opined that a business case should be developed with stakeholder input and should demonstrate that the Company's investments "will provide value beyond utility operational control."[896]

Mr. Kenworthy also opined that the Commission should tie approval of DERMS and Grid Edge funding to the Company's development of a VPP business case and implementation plan.[897] He testified about the benefits of VPPs, including lower cost peaking capacity and the deferral of distribution upgrades by shaving localized peaks,

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[893] 4 Tr 3610.
[894] 4 Tr 3611-3613.
[895] 4 Tr 3611, citing March 21, 2025 order in Case No. U-21585, pp. 117-118.
[896] 4 Tr 3612-3614.
[897] 4 Tr 3620. Mr. Kenworthy described VPPs as "an aggregation of distributed energy resources—such as smart thermostats and water heaters, residential batteries paired with rooftop solar, EV managed charging, and flexible C&I loads—coordinated to balance supply and demand and deliver utility-grade grid services." 4 Tr 3616.

and he testified there is empirical evidence showing that VPPs perform effectively.[898] He further recommended that DTE be required to file VPP program tariffs within six months, adopt a benefit-cost framework, and "[d]e-couple VPP deployment from FERC Order 2222 implementation so that retail VPPs can move forward now, rather than being delayed until wholesale participation pathways are available."[899]

MEIU witness Albers testified that while he supports the need for DERMS, he is not certain that DTE plans to implement the best option.[900] He explained that aggregators typically employ "edge" DERMS and "fleet" DERMS to manage DERs on behalf of DER owners.[901] He opined it is important that utilities do not expend resources duplicating what aggregators already have, and he expressed concern that an aggregator's edge or fleet DERMS could interfere with the DERMS that DTE plans to deploy.[902] Mr. Albers testified that, while it appears the Company has taken these issues into consideration, the Commission should "explicitly direct DTE to ensure that such interoperability is prioritized" and require DTE to "fully explain how it will coordinate its proposed Utility DERMS with its existing 'edge' DERMS as well as the 'edge' DERMS of aggregators."[903]

In rebuttal, Mr. Rademacher testified that Mr. Kenworthy "improperly calls for reductions to these valuable investments supporting future DER integration based solely on his opinion on how the programs should be developed and supported."[904] He replied that the Company's investments do not prevent future programs from being implemented,

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[898] 4 Tr 3617.
[899] 4 Tr 3621.
[900] 5 Tr 4058.
[901] 5 Tr 4058.
[902] 5 Tr 4058-4059.
[903] 5 Tr 4059.
[904] 3 Tr 939.

do not preclude customer benefits from being considered, and do not ignore load-management capabilities or interoperability with third-party aggregators.[905]

Mr. Rademacher refuted Mr. Kenworthy's claim that the Company's DERMS investment is limited to system operator control or regulatory compliance; "rather, it is a foundational platform designed to enable the future integration of customer-facing programs."[906] He also argued that the ability to observe, monitor, and control DERs is a prerequisite for implementing customer programs, and, that by funding its proposed investments, DTE will be better able to implement the type of customer programs Mr. Kenworthy supports.[907] He continued, "Without the ability to implement or administer DER programs, the Company will not be able to properly coordinate with grid operations or provide grid benefits. In fact, Witness Kenworthy recommends defunding the very programs that are seeking to enable DER adoption."[908] Mr. Rademacher also defended the Company's Grid Edge Insights and New Technology program as being structured to enable the scalable integration of new DER and NWA resources.[909] He testified, "Once these technologies are demonstrated and implemented, the ability to apply findings to future programs and scale is greatly enhanced because the foundational work has been completed and the solutions can be repeated."[910]

Mr. Rademacher testified that Mr. Kenworthy's recommendation would delay DER integration and risk compliance for required regulations such as FERC 2222.[911] He further

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[905] 3 Tr 940.
[906] 3 Tr 942.
[907] 3 Tr 940, 943.
[908] 3 Tr 944.
[909] 3 Tr 945.
[910] 3 Tr 945.
[911] 3 Tr 940, 948.

stated that disallowing funding for new technology would force the Company to halt all evaluation and adoption of new and emerging technology, and he opined that such investments are not optional but essential for the Company to adapt and maintain safe, reliable, and modern grid operations.[912]

Mr. Rademacher also disagreed with Mr. Kenworthy's proposal that the Company should be required to create a VPP program prior to funding investments in DERMS and Grid Edge Technology, testifying that "Witness Kenworthy makes no link between the Company's plans and the necessity of a VPP program and introduces this as a barrier to integration of DERs by delaying the implementation of useful capabilities."[913]

Mr. Leuker identified various concerns with Mr. Kenworthy's VPP proposal.[914] He further testified that the Company's DR portfolio includes all but one of the DERs that Mr. Kenworthy lists as potential components of a VPP.[915] He added, "Fundamentally, the Company operates its available demand response resources and programs as a 'connected' unit. It is not evident what specifically a 'VPP Tariff', or a VPP generally, would improve relative to the Company's current DR portfolio."[916] Mr. Leuker also submitted that the IRP process is a more appropriate venue to weigh the value of demand response holistically and to assess whether a VPP would contribute to the Company's demand response portfolio.[917]

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[912] 3 Tr 946.
[913] 3 Tr 949.
[914] 3 Tr 1400-1403.
[915] 3 Tr 1401.
[916] 3 Tr 1401-1402.
[917] 3 Tr 1402.

Mr. Albers provided rebuttal testimony in support of Mr. Kenworthy's VPP proposal, outlining additional considerations he believed should be taken into account when developing a VPP tariff.[918] He recommended that the Commission require DTE to incorporate its existing DR programs into any VPP program it develops; engage interested stakeholders and develop a data sharing platform; hold at least two virtual meetings to solicit input on VPP program design and share preliminary tariff language; provide opportunities for written feedback; identify best practices; and avail itself of available resources in the development of its DERMS plans and VPP tariff.[919]

DTE in its initial brief repeats the arguments presented by its witnesses against requiring a business case and the development of a VPP program as preconditions for approval of its DERMS and Grid Edge Technology spending.[920]

The CEO state that, while they support cost-effective investments enabling broader deployment and utilization of DERs, the concerns identified by Mr. Kenworthy justify the development of a business case (that includes analysis of VPPs) before approval of the Company's proposed spending on DERMS and Grid Edge Technology, consistent with the Commission's decision in Consumers Energy's recent rate case.[921] The CEO further argue that "VPPs represent an untapped capacity resource which can be deployed quicker and more cost effectively than comparable resources," and they continue Mr. Kenworthy's argument that approval of DERMS and Grid Edge spending should be tied to a VPP business case and implementation plan.[922]

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[918] 5 Tr 4064-4065.
[919] 5 Tr 4069.
[920] DTE brief, 78-80.
[921] CEO brief, 33-35.
[922] CEO brief, 38-41.

MEIU's initial brief repeats Mr. Albers' testimony, arguing that the Commission should direct DTE to ensure that any utility-managed DERMS are compatible with third-party edge DERMS and to work with stakeholders to develop a VPP program, consistent with Mr. Kenworthy's recommendation.[923]

In reply briefing, DTE reiterates its previous arguments, including Mr. Leuker's testimony that the IRP process is the appropriate venue for evaluating VPPs.[924]

In their reply, the CEO "accept the Company's proposal" to model VPPs in its upcoming IRP but disagree with DTE's contention that VPPs should not be addressed in this case, arguing that "the Company proposed its DERMS investment *in this case* and in response the CEO pointed out the applications for its investment which the Company disregarded, which include virtual power plants."[925] The CEO state that the Company bears the burden of supporting its investments and must show that it will use its DERMS to deliver value to the grid and its customers.[926]

MEIU clarify in reply that they support the CEO's recommendation that DTE be required to develop a business case as a condition for approval of DERMS spending, consistent with the requirements applicable to Consumers Energy.[927]

Finally, in its reply brief, Staff responds to the CEO's proposal that DTE file a VPP plan within six months:

> Staff would like to point out that if such a plan were filed *ex parte*, which seems to be suggested by the request to file within six months, then the tariffs could not increase the rates of non-participants. If VPP tariffs were to be incentivized by non-participants (through a monetary contribution, for

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[923] MEIU brief, 29-32.
[924] DTE reply, 61-62.
[925] CEO reply, 13-14, emphasis in original.
[926] CEO reply, 13-14.
[927] MEIU reply, 6-7.

> instance), the best place to do that would be in a rate case where the proposal could be adequately vetted.[928]

DTE is in the early stages of implementing foundational investments for the development of its DERMS infrastructure. While this case involves no dispute as to the necessity of DERMS, this PFD finds it is critical that the Company's early investments are properly focused on creating an adaptable and versatile platform that will enable future integration of diverse and emerging technologies. This PFD agrees with the CEO and MEIU that before approval of DERMS spending, the Company should be required to provide a more comprehensive justification of its DERMS proposal. As such, this PFD recommends that the Commission condition any future DERMS funding requests on the submission of a comprehensive business case, with the same requirements that were set forth in Consumers' recent rate case. There, the Commission held:

> [S]hould Consumers seek recovery for a DERMS in a future electric rate case, it is incumbent on the company to provide a business case for the program, including a comprehensive BCA, that sufficiently identifies and justifies the program's costs and benefits to customers. When developing such a business case, Consumers should look at other states' best practices for examples of plans that can be readily implemented with regard to valuing the benefits of DERs . . . . The Commission notes that development of such a business case should provide opportunities for interested persons to provide robust feedback and input into the business case and must include an analysis of the use of VPPs.[929]

This PFD therefore recommends disallowance of the Company's proposed capital spending for DERMS, consisting of $1.5 million in the bridge period and $2.8 million in the test year. However, as detailed in Mr. Rademacher's rebuttal testimony,[930] Grid Edge Insights and New Technology is a broad category that includes spending on essential

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[928] Staff reply, 21-22; see also 5 Tr 5252-5253.
[929] March 21, 2025 order in Case No. U-21585, pp. 117-118.
[930] 3 Tr 946-947.

activities related to various aspects of technological advancement. This PFD does not find it prudent to disallow those expenditures.

This PFD rejects the CEO's and MEIU's call for the development of a VPP plan and filing of related tariffs. As with DERMS spending generally, investments in VPPs should not be approved without a holistic assessment of if and how they can be utilized to bring value to the grid and to ratepayers. A better approach is to require consideration of VPPs in a DERMS business case and, as suggested by the Company and supported by the CEO, include modeling of VPPs in the Company's next IRP.

10. Grid Automation Telecommunications

Mr. Rademacher testified that grid automation telecommunications "refers to the use of telecommunications technology as an essential enabling component in the automation of electrical power grids. It involves the integration of communication systems with power distribution networks to enable real-time monitoring, control, and management of grid operations."[931] He described the telecommunications network as a "backbone system" that allows real-time visibility into the grid with two-way communications with DTE's system operations center (SOC).[932]

Mr. Rademacher next described the typical structure of a utility telecommunications network as well as the current state of DTE's grid automation telecommunications network, including efforts underway to repair and replace equipment.[933] Citing Exhibit A-12, Schedule B5.4, p. 14, Mr. Rademacher noted the parts of the telecommunications investment plan that were completed in 2023 and 2024 along

[931] 3 Tr 767.
[932] 3 Tr 767-768.
[933] 3 Tr 768-771.

with the Company's plans for 2025 and beyond.[934] He noted that while no investments are included in this case, DTE is exploring the potential benefits of a DTE-owned LTE network at some future point.[935]

Mr. De Stigter testified that he utilized five different scenarios in evaluating the grid automation telecommunications program (current communications system, public LTE (current capacity), private LTE (fiber, current capacity), public LTE (expanded use cases), and private LTE (fiber, expanded use cases).[936] He next described the BCA approach in evaluating the life-cycle costs of each of these scenarios, looking to determine which option (public or private, current or expanded use cases) would have the lowest life-cycle cost.[937]

According to Mr. De Stigter under both the current capacity scenario, where no new capabilities are required, as well as under the expanded use case scenario, the private LTE alternatives have the lowest costs.[938] He discussed additional benefits to a private network including better reliability, increased security, cost effectiveness in the event that devices must be added to the network, and avoiding the potential for increased carrier fees.[939]

In briefing, MNSC notes that Mr. Alvarez did not address grid telecommunications spend for the test year, but did take issue with the conclusion that a DTE-owned LTE network would be more cost-effective and otherwise superior to a public network,

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[934] 3 Tr 774-776.
[935] 3 Tr 776.
[936] 4 Tr 1854.
[937] 4 Tr 1855-1856.
[938] 4 Tr 1860.
[939] 4 Tr 1860-1862.

recommending a $15 million disallowance for investment in a private network. After rebuttal by Mr. Rademacher and Mr. De Stigter MNSC modifies its recommendation, stating:

> Although the Commission is not presently confronted with a request to approve costs for a Company-owned cellular network, it will be forthcoming in a future case, and it should be supported with a comprehensive assessment of all costs and benefits of both utility and public networks, including how a DTEE-owned cellular network would achieve comparable or superior security and reliability to public carriers and detailing the economic, technical, operational, and strategic pros and cons of a DTEE-owned network.[940]

This PFD finds that the additional information DTE provided in this case regarding its grid automation telecommunications program was responsive to the Commission's directive in the U-21534 order. Further, this PFD agrees with MNSC that in the event that DTE requests approval of costs to develop a Company-owned LTE network at some point in the future, it should update and refine its BCA to ensure that the benefits and costs of a private versus public LTE network are fully captured. Because no other party appears to have addressed this topic, DTE's proposed expenditures should be approved.

11. Engineering and Support Functions

Mr. Kryscynski testified that DTE is proposing to significantly increase its engineering and support personnel due to the "increasing complexity and scale of its distribution system transformation[,]" citing the need for more engineering support to effectively execute the Company's DGP.[941] He added that the Company is also anticipating the integration of more DERs and more reliability upgrades, further testifying

[940] MNSC brief, 117.
[941] 3 Tr 1193-1194.

that “Through normal attrition, the departure of key engineering personnel and subject matter experts has created critical resource gaps that must be addressed. Without additional in-house engineering expertise, the Company risks delays in project execution, inefficiencies in system upgrades, and challenges in maintaining long-term reliability goals and improvements.”[942]

Mr. Kryscynski further testified that in addition to increasing the Company’s in-house engineering workforce, DTE is also expanding partnerships with outside engineering and design firms to handle detailed design work and increase capacity and flexibility. Referencing page 15 of part two of the Liberty Audit, Mr. Kryscynski noted that the audit found that “DTE appears to require significantly more engineering personnel” and that absent more support, the Company may not be able to achieve its goals in terms of program execution and reliability improvements.[943] Accordingly, he projected that DTE will spend $8.3 million in O&M.

Mr. Coppola recommended disallowance of $8.3 million in O&M expense as well as $16.9 million in 2025 and $5.63 million in 2026 in capital expenditures for the engineering support program. Mr. Coppola explained that in discovery, he asked for the number of employees and contractors to be added in 2025 and 2026 along with the number of employees in these roles historically. In addition, he requested information on the projects these employees would be working on and how the Company derived the $8.3 million O&M expense.

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[942] 3 Tr 1194
[943] 3 Tr 1195-1196.

Mr. Coppola stated that in response, DTE identified 209 new hires for 2025 and 2026, but could not provide how many employees previously worked in these positions or what new projects or programs these employees would be assigned to.[944] With respect to proposed capital expenditures, Mr. Coppola explained:

> The calculation of the incremental $8.3 million of O&M expense for 2026 shows that a larger amount of $22,517,599 is included in capital expenditures for 2025 and 2026. Based on the number of employees to be hired each year, I calculated the portion of the total cost assigned to 2025 capital expenditures to be $16,888,000 with the remaining amount of $5,630,000 assigned to 2026 capital expenditures.[945]

Based on his assessment, Mr. Coppola opined that DTE had failed to adequately justify the addition of 209 employees in 2025 and 2026. Accordingly, he recommended disallowance of $16.9 million and $5.63 million in capital expenditures in 2025 and 2026 respectively, along with $8.3 million in O&M expense in the test year.

In rebuttal, Mr. Kryscynski opined that DTE provided "a significant amount of evidence" for the increase in engineers and support personnel, testifying that "Witness Coppola provides no explanation as to why this evidence still isn't enough."[946] Referring to his direct testimony, Mr. Kryscynski reiterated that addition personnel is needed to address resource gaps and to support new initiatives, again citing the increasing complexity and scale of the distribution grid, as well as the findings of the Liberty Audit.[947]

In response to the Attorney General's questions about historical numbers of employees, Mr. Kryscynski testified that no historical numbers could be provided because

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[944] 4 Tr 3470.
[945] 4 Tr 3470-3471.
[946] 3 Tr 1259.
[947] Id., 1262.

the funding requested is for new positions; thus, there is no historical data. And, referencing Exhibit AG-16, he explained that:

> [A]n increase in engineering and support personnel is intended to address multiple projects and programs, with specific assignments determined by the operational needs of the Company at the time of employment. It's important to note that the Company's Distribution engineers support all the Company's distribution capital and O&M activities so new employees have the possibility to be assigned to support any project – and will likely be supporting multiple projects in some capacity. These assignments will change over time as projects are added and completed.[948]

Responding to Mr. Coppola's proposed capital adjustments Mr. Kryscynski stated that the disallowance should be rejected, explaining that "[a]s part of the projects that support the increasing investment in the grid, the capital required is already accounted for in the Company's A-12 Exhibit request as part of the Company's capital support overheads." He added that the investment is unavoidable, whether or not the Company hires the additional staff because DTE would have to rely more on contractors and overtime to maintain operations.

In briefing, the Attorney General argues that DTE's "inability to provide any information on who was previously doing this work or roughly how many employees were engaged in it is troubling, as it shows a lack of attempt by DTE to support its requests, even when asked directly."[949] She further contends that Mr. Kryscynski's rebuttal, which indicates that new employees could be assigned to a variety of different functions "underscores the uncertain nature of these roles and the lack of support in this case for their necessity[.]"[950]

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[948] 3 Tr 1260.
[949] Attorney General brief, 66.
[950] Id.

In response to Mr. Kryscynski's claim that DTE did not request any capital for engineering and support staff, the Attorney General asserts that the Company's response is confusing but that "the gist of DTE's argument is that the identified capital costs are an additional part of the Company's ask in this case, so without these additional positions, those costs will not have adequate personnel support. However, this is an inappropriate approach, as it presupposes that all of the capital projected in A-12 will be approved by the Commission."[951]

In its brief, DTE relies on Mr. Kryscynski's testimony and rebuttal, emphasizing that the Company did provide the Attorney General with a detailed requirements list including job category, type, and expected cost, and claims to the contrary should be rejected.[952]

This PFD finds that DTE's request for $8.3 million in O&M for additional engineering and support personnel should be approved. As DTE points out, one of many key findings in the Liberty Audit was that the Company is in need of additional engineers in order to carry out its Strategic Distribution programs. Further, this PFD agrees with DTE that: (1) historical information is not available because these are new positions; and (2) the provision of a precise description of each new job function is not feasible given that the new employees will be assigned to various tasks, in accordance with operational needs.

As for the Attorney General's adjustment for capital expenditures purportedly associated with these positions, it is unclear how Mr. Coppola derived these disallowance amounts, and in any event, it appears that the overhead amounts are tied to projects and

[951] Attorney General brief, 67.
[952] DTE brief, 164, citing 3 Tr 1260.

not to personnel. Thus, it appears that if a project's costs are disallowed, in full or in part, the amount disallowed will include overhead.

12. Other Distribution Issues

Mr. Woolley testified that, using Company data, he conducted an analysis of the Company's transformer network that modeled transformer network-level load profiles under a range of building and vehicle electrification scenarios.[953] He explained that he compared projected loads against the existing transformer network capacity considering the effects of seasonal temperature differences on the effective ratings of the transformers.[954]

Mr. Woolley stated that his analysis demonstrated that DTE is using only a fraction of its available transformer network capacity with average residential line transformers peaking at under 40% capacity, commercial line transformers at under 15%, and substation transformers at roughly 48%.[955] He drew two conclusions from his analysis: (1) seasonal headroom allows the Company's system to accommodate more winter load before reaching the same thermal stress as in summer months, and (2) the need for system-wide transformer upgrades are not imminent.[956] Mr. Woolley recommended that DTE be required to submit circuit- and substation-level loading and thermal analyses modeled under multiple electrification scenarios to support any grid plan or capacity project that seeks justification based upon system loading.[957]

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[953] 5 Tr 4811.
[954] 5 Tr 4811.
[955] 5 Tr 4813
[956] 5 Tr 4816.
[957] 5 Tr 4818.

In a related vein, Mr. Stephens recommended implementing circuit-specific load forecasting capability before the Company's next rate case.[958]

In rebuttal, Mr. Leuker testified that the Commission already addressed distribution system planning guidelines in its July 10, 2025, order in Case No. U-20147. He recounted the Commission's directive regarding circuit-level load forecasting, and he stated that the Company intends to comply with the order and utilize circuit-level load forecasts that consider various electrification scenarios.[959]

In both initial and reply briefs, neither MNSC, the Attorney General, nor the Company further addressed this issue.[960]

This PFD finds persuasive the rebuttal testimony of Mr. Leuker that the Commission has recently provided guidance on this topic in Case No. U-20147 by updating distribution system planning guidelines to require circuit-level load forecasting that involves various scenarios modeling high and low electrification.[961] Accordingly, this PFD finds no need to take further action on this topic.

G. Community Lighting

Mr. Hartley discussed DTE's Community Lighting capital expenditures as set forth in Exhibit A-12, Schedule B5.5. In its brief, the Company notes that no party took issue with historical spend of $18.3 million in 2023, and projected spend of $27 million for 2024, $17.7 million in 2025, and $17.7 million in the test year. The proposed costs should

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[958] 5 Tr 4518.
[959] 3 Tr 1373-1374.
[960] However, MNSC's brief does reference Mr. Woolley's testimony regarding DTE's transformer network, but only in relation to witness Jester's recommendation to present seasonal volumetric distributions rates. See MNSC brief, 191.
[961] See 3 Tr 1373; See also July 10, 2025, Order in Case No. U-20147, pp. 23-24.

therefore be approved. Community Lighting O&M expense and rate design issues are addressed below.

H. Demand Response

Mr. Leuker testified regarding DTE's DR programs and projected spend, as set forth in Exhibit A-12, Schedule B5.6. As discussed by Mr. Leuker, the Company's programs include interruptible space conditioning (CoolCurrents), programmable thermostats (SmartCurrents) and Other DR programs and pilots "including $1.990 [million] of disallowed C&I battery costs from Case No. U-21297."[962]

While the Company's proposed expenditures for CoolCurrents and SmartCurrents were not contested, Staff and MEIU raised concerns about the C&I battery pilot, DTE's proposal to modify the three-phase method for addressing DR costs and cost recovery, and DTE's methods for procuring DR resources. These issues are addressed below.

1. Commercial and Industrial Battery Pilot

Mr. Leuker testified that the C&I Battery Storage Pilot is a behind-the-meter (BTM) BESS to be located at two customers' sites with the goal of achieving peak demand shaving or shifting during demand response events.[963] He stated that both batteries are currently in storage and that, while the Company has identified one customer, it has not found a second external customer such that "[a]n alternative option for the second battery is to leverage it internally at one of DTE's locations."[964] Mr. Leuker acknowledged that while the C&I battery pilot received Commission approval in previous rate cases, the

[962] Exhibit A-12, Schedule B5.6, p. 1, fn (1).
[963] 3 Tr 1353.
[964] 3 Tr 1355.

Commission has not approved expenditures related to the second battery because DTE had not yet identified a customer that would utilize it in the pilot program.[965]

Staff witness Matthews recounted that this pilot was previously approved with respect to one customer, but the Company has been unsuccessful in locating a second participant such that the Commission previously denied cost recovery for the second battery.[966] He explained that because DTE has been unable to find a second participant, the Company now proposes using the second battery at one of its own sites as part of non-wires alternative (NWA) project. Mr. Matthews opined that the Company already has several battery NWA pilots and that it failed to describe how this installation or pilot would differ from currently existing pilots. He concluded that costs of $508,000 related to the second battery should be disallowed.[967] He added that if DTE pursues another use case for the second battery, it should be dissimilar to the other already extant battery use cases that the Company is exploring through NWA pilots.[968]

Dr. Sherman provided testimony that summarized the purpose of the C&I battery pilot and the Commission's previous disallowance related to the second battery because DTE failed to find a second participating customer.[969] Dr. Sherman recounted the Company's plan to use the second battery itself at a DTE site, dismissing it as "conjuring up a second 'customer' from an internal DTE Electric business unit."[970] She opined that deploying the battery through an internal business unit of DTE would not allow the

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[965] 3 Tr 1355-1356 (referencing orders in Cases U-21297, U-21403, and U-21534).
[966] 5 Tr 5084 (citing the Commission's orders in cases U-21534 and U-21297).
[967] 5 Tr 5084-5085. See also Exhibit S-14.1.
[968] 5 Tr 5086.
[969] 5 Tr 4030-4031 (Referencing Orders from Cases U-21297 and U-21534).
[970] 5 Tr 4032.

Company to achieve several objectives for the pilot, including: (1) gaining an understanding of customer interest in hosting a battery storage system; (2) gaining operational experience with off-site batteries; and (3) exploring the feasibility of sharing control with an external customer.[971] She opined that the Commission should not approve the proposed spending for the second battery.[972] Dr. Sherman also reiterated her consistent opposition to utility ownership of BTM batteries in several rate cases, and she recommended that the Commission should disallow further spending on this pilot and disapprove of any expansion of this program or any similar future pilot involving utility ownership of BTM batteries.[973]

In rebuttal, Mr. Leuker objected to Staff's proposed disallowance asserting that it was based upon the mistaken premise that the second battery would be used for NWA purposes, e.g. for preventing substation overload.[974] He testified that:

> Instead, it will be housed in a controlled environment that allows for testing on the grid in a safe manner, with equipment that can perform repeatable scenarios of expected events. This will allow for 1) experimentation and stacking of different energy storage use cases, 2) evaluation of compensation models, 3) answering key questions around wholesale market integration (as contemplated by the Commission's Order in MPSC Case No. U-21032), in addition to addressing the DR-related objectives as outlined in question 98 on page 55 of my direct testimony. These learnings will be critical to optimizing the use of batteries going forward and therefore, the capital costs associated with the second C&I DR battery should be approved.[975]

Regarding Dr. Sherman's testimony, he rejected the insinuation that DTE disregarded the previous disallowances by purchasing the second battery. He explained

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[971] 5 Tr 4033.
[972] 5 Tr 4034.
[973] See generally 5 Tr 4034-4037.
[974] 3 Tr 1382.
[975] 3 Tr 1382.

that both batteries were purchased at the same time, and spending on the second battery was the result of milestone payments agreed to by DTE and the manufacturer before the Commission's past disallowance.[976] Mr. Leuker also addressed Dr. Sherman's concerns about the Company using the second battery itself by stating that, "[n]owhere in Staff's testimony or the Commission's orders around the second battery spend was it specified that the second customer must be external."[977] He asserted that DTE was unsuccessful in finding a second external customer due to the high costs and associated savings, but that the Company successfully pivoted to find an internal customer that could utilize the battery.[978]

DTE's brief repeats Mr. Leuker's direct and rebuttal testimony. The Company emphasizes that, contrary to Staff's assertion, the second battery will not be used for NWA projects and will instead be used for the purposes stated in Mr. Leuker's rebuttal testimony.[979]

Staff's brief emphasizes that its proposed disallowance is not premised upon the second battery's duplicative usage in a NWA-like project; instead, Staff states that the disallowance is necessary because the Company failed to find a second customer to host the battery and has not made a specific proposal about how the second battery will be used.[980] Staff adds that it agrees with MEIU witness Sherman's assessment that

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[976] 3 Tr 1383.
[977] 3 Tr 1383.
[978] 3 Tr 1384.
[979] DTE brief, 93; see also 3 Tr 1382.
[980] Staff brief, 72.

deploying the battery through an internal business unit will not allow DTE to meet some of the objectives set out by the Company in its business use case for the pilot.[981]

MEIU's briefing asserts that Mr. Leuker's rebuttal does not truly address Dr. Sherman's criticism, including the primary charge that the C&I battery pilot, as originally conceived, has failed.[982] MEIU encourages the Commission to deny cost recovery for the second battery, direct DTE to avoid proposing any similar pilot in the future, and to explore alternatives to the use of BTM batteries such as rate design changes.[983]

In its reply, DTE rejects MEIU's call to explore alternatives to battery storage such as rate design changes or pilots that do not involve BTM batteries. The Company states that "such exploration is unnecessary" and that its C&I battery pilot "has not failed to meet the objectives of the pilot at its inception" because the company found at least one external customer.[984] Staff and MEIU provide no further argument in their reply briefs.

This PFD agrees with Staff and MEIU and therefore recommends disallowing $508,000 related to the pilot's second battery. This PFD finds persuasive the reasoning of Staff and MEIU that the Company's failure to find a second external customer to participate essentially indicates that the pilot was not successful in achieving its goal of finding two customers, and utilizing the battery internally will not allow the company to meet all the pilot's originally planned objectives. This PFD is not swayed by DTE's argument that there was no specification that the second participating customer had to be external because such a condition is virtually self-evident.

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[981] Staff brief, 73.
[982] MEIU brief, 26.
[983] MEIU brief, 27.
[984] DTE reply, 75.

2. Demand Response Regulatory Framework

Mr. Leuker testified that the Company believes the Commission's three-phase DR framework established in Case No. U-18369 is no longer necessary and causes confusion. Accordingly, he recommended removal of DR from rate cases and implementation of a separate DR plan filing with a surcharge that is adjusted annually.[985] He explained that while DTE is not proposing to change the regulatory framework in this filing, "the Company is interested in working with MPSC Staff and other stakeholders to develop a regulatory framework that works for all parties if the Commission agrees a collaborative would be appropriate."[986]

Mr. Towslee testified that while Staff is in favor of changes to the DR framework, the Commission is already considering the issue in Case No. U-21637, and he recommended that DTE submit its suggestions through comments in that case.[987]

Dr. Stults testified that Ann Arbor is happy to collaborate on issues involving DR, but the City does not support removing DR from rate cases.[988] She also expressed her opposition to implementing a DR surcharge because it could result in DR being disfavored by ratepayers.[989]

DTE does not address this issue in its initial brief. Staff's brief reiterates Mr. Towslee's argument that this topic should be addressed in Case No. U-21637.[990] Ann Arbor relies on the testimony of Dr. Stults to argue against removing DR from general rate

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[985] 3 Tr 1339-1340.
[986] 3 Tr 1341.
[987] 5 Tr 5162.
[988] 4 Tr 3737.
[989] 4 Tr 3737-3738.
[990] Staff brief, 161.

cases or implementing a DR surcharge, and the City states that it thoroughly discussed its position on this issue in comments submitted in Case No. U-21637.[991]

The parties do not address this issue in their reply briefs.

This PFD notes that while DTE did not provide rebuttal testimony or brief this issue, the Company did submit comments on September 10, 2025 in Case No. U-21637 addressing its stance on the DR framework. This PFD finds that the Company's concerns are more appropriately addressed in that venue and there is no need for further discussion in this PFD.

3. Demand Response Resource Procurement

Mr. Leuker testified that as part of the Company's 2022 IRP settlement agreement in Case No. U-21193, DTE agreed to procure DR-related MISO Zonal Resource Credits (ZRCs) through a competitive bidding process. The Company specifically agreed to issue two 25 MW solicitations (one each for the 2025/26 and 2026/27 Planning Years) and a 100 MW solicitation for the 2027/28 Planning Year. He testified that the first Request for Proposal (RFP) for 25 MW was developed with the assistance of Guidehouse and issued on June 26, 2024 but resulted in no bids from the 14 aggregators invited to bid. He stated that with the goal of improving the RFP for the second solicitation, the Company contacted bidders to gather feedback but received no response despite multiple attempts.

Mr. Leuker further testified about the history of DR aggregation in Michigan and expressed the Company's concerns with lifting the ban on resources smaller than 1 MW.

[991] Ann Arbor brief, 14-15.

MEIU witness Albers testified that the Commission should direct DTE to improve its DR procurement process in four ways. First, he recommended that the Company not require an aggregator to provide the full 25 MW of DR capacity and opined that multiple aggregators providing lesser amounts of capacity will improve the results of the RFP. He added that if DTE allows more than one aggregator to participate, it could consider utilizing an "aggregator of aggregators" to integrate and manage the aggregators that successfully bid DR resources. Second, he recommended that DTE no longer require the aggregator to serve as the MISO Market Participant; "DTE may be more likely to receive bids if it acts as the [Market Participant] and aggregators are responsible for submitting all necessary site-specific information to DTE." Third, Mr. Albers testified that DTE should not limit the RFP to only invited aggregators. In this vein, he expressed concern that the 2024 RFP included entities that are not aggregators (including MEIBC and AEM-Alliance, which are trade organizations) and redundant entities (Ecobee and Generac Power Systems are part of the same organization). And fourth, he testified it is not clear whether DTE is contemplating a pay-for-performance model, but he opined aggregators are more likely to participate in such a program because customers with DERs are more likely to participate when an event is called if there is an incentive to do so.

Mr. Albers further testified that it would be easier for DTE to achieve its obligation under the settlement agreement if the Commission were to lift the ban on resources smaller than 1 MW from participating in DR aggregation, and he addressed Mr. Leuker's concerns with lifting the ban. He "encouraged" the Commission to lift the ban as soon as possible and "urged" DTE to support such a change.

In rebuttal, Mr. Leuker testified that DTE has complied with the settlement agreement to date by launching RFPs for both the 2025/26 and 2026/27 Planning Years. He stated that the most recent RFP invited 17 aggregators to bid and was issued on April 10, 2025, but, like the first solicitation, the Company received zero bids. Mr. Leuker disagreed with Mr. Albers' reference to DTE's "obligation" to procure DR resources under the settlement agreement; he testified that the Company is instead required to "target" DR resources through a competitive bidding process, which it has done.

Responding to Mr. Albers' criticisms of the procurement process, Mr. Leuker testified that one aggregator should have been able to procure 25 MW of DR. Nevertheless, the Company plans to allow multiple aggregators to procure less than 100 MW in the third solicitation, "in hopes of a successful DR procurement." He testified that Mr. Albers failed to support his suggestion that DTE should be the MISO Market Participant instead of the aggregator, and he opined that the Company's approach is necessary to protect it and its customers from financial harm. He elaborated: "If DTE Electric were to be the Market Participant, all the risk for underperformance, and any corresponding penalties, would fall to the Company along with increased responsibilities such as daily market offers, communications between MISO and DR resources, DR testing requirements, MISO settlements and meter data submissions." Mr. Leuker further testified that the Company's RFP provides instructions on how non-invited bidders can submit a bid and that this provision was used in both solicitations to invite a bidder that was not on the original bidder list.

Next, Mr. Leuker testified that the RFP was sent to trade associations "as a courtesy and to make them aware of the RFP and share with aggregators in their

membership or in the broader DR industry," and he explained that Ecobee was added to the original bidder list at its request despite being part of Generac. He also replied that DTE partnered with Guidehouse "in good faith to identify aggregators that might be interested in bidding but also understood the reality that not every single aggregator could realistically be invited to bid." Mr. Leuker testified that the RFPs leave the responsibility for customer incentives to the aggregator, and he opined that it would not be beneficial for the Company to both pay an aggregator and issue customer incentives.

Mr. Leuker disputed Mr. Albers' suggestion that DTE is unfamiliar with working with aggregators, testifying that the Company already has a relationship with EnergyHub in connection with its opt-in thermostat program and has also worked with other program implementers such as ICF, Generac, and Weavegrid. He reiterated the Company's concerns with lifting the aggregation ban and stated that the Commission in Case No. U-21099 expressed similar concerns with residential customers participating in DR aggregation, which resulted in implementation of the 1 MW minimum.

DTE did not address this issue in its initial brief. In its brief, MEIU argue that Mr. Leuker failed to offer any alternatives that would improve the Company's procurement process, and he incorrectly assumes that "it does not matter from the perspective of compliance with the IRP Settlement whether DTE's procurements are successful or not." It proposes that the settlement obligation to "target" 150 MW of new DR requires the Company to "explore and adopt best practices from other markets successfully operating with third-party aggregators." MEIU concludes that the Commission should direct DTE to investigate and propose new ways to improve its DR procurement prior to the 100 MW solicitation.

In reply, DTE reiterates Mr. Leuker's rebuttal arguments.[992] The Company further asserts that it "remains open to input regarding best practices" and "continues to proceed with the RFP consistent with the IRP Settlement," and therefore the Commission need not provide guidance in this regard.[993] MEIU's reply brief did not add any further argument on this issue.

This PFD finds that DTE effectively rebutted each of the four criticisms MEIU raise regarding the Company's DR procurement process and that the Company has made reasonable efforts to comply with its obligation under the 2022 IRP settlement agreement to "target 150 MW of new DR through a competitive bidding process." This PFD notes that DTE partnered with a consultant to assist with the process, and the Company has made efforts to improve the procurement process after its first RFP was unsuccessful. In addition, this PFD finds that issues concerning the modification of resource procurement processes for DR and other resources are more appropriately addressed in the Company's upcoming IRP.

I. Information Technology (IT)

The Commission's extensive and detailed requirements for IT projects are set forth in the April 25, 2024 order in Case No. U-18238, Docket Entry No. 0106, Attachment 11.

Mr. Ambrose presented the Company's IT capital expenditures and the Company's underlying analyses and decisions related to those investments. Mr. Ambrose testified that the Company's key IT investment drivers are: (1) cybersecurity for grid reliability and customer protection, (2) reliability and resiliency of IT assets, and (3) affordability (or cost

[992] DTE reply, 75-77.
[993] DTE reply, 77.

effectiveness), and that those drivers are reflective in the expenditures that it is seeking to recover in this case.[994]

In support of the IT requests, Mr. Ambrose sponsored Exhibit A-12, Schedule B5.7, Exhibit A-13, Schedule C5.13, and Exhibit A-24, Schedules N1 through N8. Per those exhibits, the Company is seeking capital expenditures of $174.6 million for the historical year, $163.6 million for the 2024 bridge period, $168.1 million for 2025 bridge period, and $204.9 million for the test year.[995]

Mr. Ambrose testified that the Company "reassessed" its approach to IT investment and "made enhancements" to the IT project identification and selection process since its last rate case, which resulted in a "strengthened" approach for the 2025 investment planning cycle.[996]

Mr. Ambrose explained that Exhibit A-12, Schedules B5.7 through B5.7.9, Exhibit A-24 Schedules N1 through N3, and Exhibit A-13 Schedule C5.13 provide the IT project information required by the Commission.[997] Pointing to Exhibit A-24, Schedule N-3 and Exhibit A-12, Schedule B5.7, Mr. Ambrose testified that capital costs for hardware, software and software development are included in the IT costs in accordance with the Company's accounting policies which define the scope and phases of a project that can be capitalized and the scope and phases of the project that should be expensed. Mr. Ambrose stated that under the Company's policies, the corresponding O&M costs for IT

[994] 4 Tr 2113-2115, 2124.
[995] 4 Tr 2129-2131, Figures 3 and 4.
[996] 4 Tr 2123-2129.
[997] 4 Tr 2131-2133.

projects are considered “cost-to-achieve” and are provided for informational purposes only.[998]

Mr. Ambrose explained that the Company’s IT investments are divided into “Portfolios and Categories.”[999] There are four Portfolios: Shared IT, Corporate Applications, Plant & Field, and Customer IT. The Shared IT Portfolio is also divided into sub-portfolios: Information Technology for IT (IT for IT), Information Protection Security (IPS), Infrastructure Operations, Enterprise Data Analytics, and Innovations.[1000] Within each Portfolio (or sub-portfolio), the Company organizes and plans its investments using the following five Categories: Regulatory/Compliance, Sustainment, Return-to-Health, IT Enhancements, and Strategic.[1001] He said that when a project applies to multiple categories, DTE will categorize it according to the category that represents the project’s most prominent purpose and features.[1002]

Staff witnesses Rogers, Zichi, and Klocke presented Staff’s analysis of the reasonableness and prudency of the Company’s IT investment plan and sponsored Exhibits S-12.1 through S-12.12. Staff recommends a total IT capital expenditure disallowance of $2.294 million in the 2023 historical year, $36.617 million disallowance in the bridge period ($6.1 million in 2024 and $30.517 million in 2025), $45.338 million disallowance in the test year, and an IT O&M disallowance of $6.526 million.

Of the numerous IT investments DTE proposes, Staff recommended adjustments to 12 specific projects, to projects categorized as having “Level 2” and “Level 3” cost

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[998] 4 Tr 2133.
[999] 4 Tr 2115.
[1000] 4 Tr 2116.
[1001] 4 Tr 2116.
[1002] 4 Tr 2116-2117.

estimates, and to projects with "Projected Overhead and Other Costs (Capital)." No other party presents arguments regarding DTE's IT investments. The contested issues are addressed in the subsections below.

1. Specific IT projects

Mr. Ambrose testified that investments in the Customer IT Portfolio directly influence the Company's interactions with customers.[1003] He explained that the investments planned within the Customer IT Portfolio span all the investment categories.[1004]

The first five projects at issue are within the Sustainment category of the Customer IT Portfolio and are described further below.[1005] In discussing the Sustainment category, Mr. Ambrose testified that the investments in this Category are non-discretionary because they are required to maintain existing applications that are critical to the Company's day-to-day operations.[1006] He explained that investments in functional periodic releases, infrastructure upgrades (adaptive maintenance), performance tuning, and data storage enhancements to ensure the reliability and resilience of IT assets are examples of Capital spending in this category.[1007]

a. Customer Insight Platform Application Health.

The Company plans to invest $4.3 million in the test year for the Customer Insight Platform Application Health Project.[1008] Mr. Ambrose explained that through a vendor,

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[1003] 4 Tr 2120.
[1004] 4 Tr 2120.
[1005] 4 Tr 2262-2263; Exhibit A-12, Schedule
2 B5.7.2, lines 11-28.
[1006] 4 Tr 2122.
[1007] 4 Tr 2122.
[1008] 4 Tr 2265-2266; Exhibit A-12, Schedule B5.7.2, line 15.

Powerley, this project will provide annual maintenance, upgrade, and other support services.[1009] It will also provide key architecture components and cloud computing services, such as Amazon Web Services, to maintain several of DTE Electric systems, including the DTE Insight mobile app and Energy Bridge devices.[1010] He testified that Powerley offers reliable and "proven specific expertise," has an "excellent" track record of performance in this area, and has developed and supported systems for DTE external customers.[1011]

Ms. Klocke testified that Staff recommends a full disallowance of capital expenditures and O&M costs for this project.[1012] She explained that the Customer Insight Platform Application Health project is the Company's attempt at renaming and continuing the "Powerley Customer Platform Application Health initiative."[1013] Pointing out that the Company began investing in the project in 2014, Ms. Klocke notes that the Commission disallowed $2.7 million in capital expenditures for the program in Case No. U-21297 due to low customer engagement and participation.[1014] She testified that in Case No. U-21534, the Company reporter an "expected" increase in the number of Insight App users and Energy Bridge requests and received $4.0 million for its costs for app maintenance, software licensing, and customer support.[1015]

Ms. Klocke cited DTE's discovery responses in this case which show 2.17% of its electric customers use the Insight App monthly and 1.26% of customers use the Energy

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[1009] 4 Tr 2265.
[1010] 4 Tr 2265.
[1011] 4 Tr 2266.
[1012] 5 Tr 5114.
[1013] 5 Tr 5114-5115.
[1014] 5 Tr 5114-5116.
[1015] 5 Tr 5115.

Bridge device.[1016] She concluded that the Company remains unable to show that customer participation warrants recovery of the requested capital and O&M costs for the project.[1017]

In rebuttal, Mr. Ambrose acknowledged that Staff correctly identified the Customer Insight Platform Application Health project as the former Powerley Customer Platform Application Health project.[1018] He also admitted that monthly customer usage represents 2.17% of the Company's electric customer base, but he justified cost recovery for the project, claiming that customer downloads increased "substantially" since Case No. U-21534 and are up to 19.1% of its customer base.[1019]

Mr. Ambrose also testified that the project has several customer benefits including improved customer experience, funding ongoing app maintenance and upgrades, software licensing, and customer support, as well as enabling enhancements to the Bill Management tool.[1020] He stated that the investments in the tools supported by this project have also achieved lower call volumes to Contact Resolution Specialists (CRS). Mr. Ambrose testified that disallowing funding would mean the Company's BillWise AI tool, which it piloted for 6 months in 2025, would not be released to the broader customer population, the Bill Management tool and the DTE Insight App would become unstable and unreliable and result in increased calls to CRS, and the Energy Bridge tools would lose licensing and could no longer be used.[1021]

[1016] 5 Tr 5115-5116; Exhibits S-17.3 and S-17.4.
[1017] 5 Tr 5115.
[1018] 4 Tr 2354-2359.
[1019] 4 Tr 2359-2361.
[1020] 4 Tr 2358, 2360
[1021] 4 Tr 2362-2363.

DTE's brief reiterates full investment is justified, relying on Mr. Ambrose's testimony that the project provides many customer benefits and that customer usage has increased since 2023.[1022]

In its brief, Staff relies on Ms. Klocke's testimony to support full disallowance of the requested costs for the project.[1023] Staff also responds to Mr. Ambrose's claim that downloads of the Customer Insight App have increased from 2023 to 2025, arguing that downloads and usage are not equivalent.[1024] Staff maintains that because the Company has failed to demonstrate significant customer usage of the Customer Insight App, and its various elements, recovery of the costs for the Customer Insight Platform Application Health project should be disallowed.

In reply briefing, DTE emphasizes its prior arguments and further reasons that accepting Staff's recommendation to disallow funding would mean that the "momentum of this [BillWise AI] tool will be halted before it can grow further and produce more customer benefits," and that the Bill Management tool and DTE Insight App will become "unstable and unreliable."[1025]

Staff's reply brief stresses that the low App usage is troubling because the Commission encouraged DTE to boost engagement in 2023, further arguing that disallowance is reasonable because the Company has never demonstrated via customer feedback or input that the purported other benefits from the project have been realized, "namely that the App will improve customers' experiences."[1026] Staff further argues that

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[1022] DTE brief, 108-110.
[1023] Staff brief, 84-85.
[1024] Staff brief, 85.
[1025] DTE reply, 84.
[1026] Staff reply, 2-3.

the Company has not offered evidence to show that the Bill Management tool and DTE Insight App will become unstable and unreliable if this project is not approved.[1027]

This PFD finds that Staff's adjustment should be adopted. Funding for this project was deemed unwarranted due to low customer engagement and participation in 2022, when the project was then nine years old, and the Commission fully disallowed it in 2023, DTE reported an expected increase in usage and the Commission found reason to fund the maintenance, licensing and other supportive costs for the project. Although presented under a different name in this case, this project is now fourteen years old and customer engagement and participation remain low (and arguable lower than in 2022). Consistent with the Commission's prior decision to disallow all costs and despite any of the purported benefits to customers, DTE has again failed to establish sufficient or sustained interest in the project to warrant expenditure. Accordingly, this PFD recommends disallowance of $4.3 million in capital expenditures and $100,000 in O&M expense for the Customer Insight App Health program.

b. Customer Relationship and Billing Program.

The Company is requesting $6.3 million capital and $2.695 million in O&M for the Customer Relationship and Billing (CR&B) Program for the test year.[1028] Mr. Ambrose explained that the CR&B is a fully implemented system that requires regular maintenance while also providing a high level of availability with accurate data to meet the needs of the Customer Service, Billing and Metering, Distribution Operations, Energy Optimization, Treasury, Controller, Gas Operations, and Electric and Gas Sales and Marketing

[1027] Staff reply, 3-4.
[1028] 4 Tr 2267-2270; Exhibit A-12, Schedule B5.7.2, line 17; Exhibit A-24, Schedule N3, line 332.

organizations, in order to provide customers efficient and cost effective service.[1029] He also said that to streamline processes, enhance operational efficiency, improve service delivery, and optimize costs, this project will also include the costs associated with integrating the Automated Application Monitoring Health, Closed Loop COCL Application Health, Customer Information Technology Configuration Management and Customer Legacy Application Health projects into the CR&B program.[1030]

Ms. Klocke testified that Staff recommends a full disallowance of the requested costs for the CR&B program.[1031] She questioned the type and scope of the enhancements and maintenance that DTE claims will be performed under the CR&B program based on the lack of information provided during audit.[1032] She also testified that Staff sought additional detail beyond what was provided in Exhibit A-24, Schedule N3 to determine how the CR&B project would benefit customers, the value it would offer, and why it was necessary at this time, but DTE did not provide sufficient response.[1033]

In rebuttal, Witness Ambrose countered that the program's maintenance activities occur daily, monthly, and annually for system and application patches to maintain the continuity, sustainability and reliability of the CR&B platform.[1034] He testified that the CR&B project provides customer benefits through:

> 1) integration and streamlining processes and applications across four application health projects,

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[1029] 4 Tr 2267.
[1030] 4 Tr 2268.
[1031] 5 Tr 5116-5117.
[1032] 5 Tr 5117 citing Exhibit S-17.6.
[1033] 5 Tr 5117-5118 citing Exhibits S-17.7, S-17.8, S-17.9.
[1034] 4 Tr 2365.

> 2) maintenance of the CR&B system to reduce system downtime and the inability to serve customers,
>
> 3) the management of system defects that reduce the accessibility or performance of the CR&B system and make minor enhancements to ensure the system stays up-to-date with current business processes and to sustain or improve customer transaction metrics.[1035]

He also reiterated his direct testimony that the scope and associated costs of multiple projects were integrated into the CR&B Program.[1036]

DTE's brief relies on Mr. Ambrose's direct and rebuttal testimony as support for its argument that the CR&B is a necessary program that plays a "critical role" and warrants the requested funding.[1037]

In its brief, Staff maintains that the CR&B program should be disallowed because the Company did not fully explain the requested costs. Staff argues that the Company has not shown why the program's costs are extremely high for an ongoing, fully implemented program that only requires maintenance.[1038]

The Company's reply briefing reiterates its previous points, emphasizing that the project costs are high because four application health projects are included and the consolidation is intended to improve service delivery and cost management.[1039]

This PFD finds that DTE did not support the reasonableness and prudence of its proposed expenditures for this project and Staff's recommendation should be adopted. In Case No. U-21534, DTE sought recovery for the maintenance needs of the CR&B at a rate that is drastically less than what it seeks in this case (DTE requested $1.9 million

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[1035] 4 Tr 2364.
[1036] 4 Tr 2364 citing 4 Tr 2268.
[1037] DTE brief, 111-112.
[1038] Staff brief, 94-95.
[1039] DTE reply, 89-91.

capital compared to $6.3 million capital here and it requested $0.16 million in O&M compared to $2.7 million in O&M in this case).[1040] And at that time, DTE reported that the costs for the program "are consistent year after year, as it represents fixed-capacity technical teams."[1041] Even if the costs for the project include integrating the Automated Application Monitoring Health, Closed Loop COCL Application Health, Customer Information Technology Configuration Management and Customer Legacy Application Health projects into the CR&B program, DTE's description of the project is too generalized to persuasively explain the extreme increase in costs or how the project achieves its stated goal of cost management. Consistent with Staff's assessment, this PFD recommends disallowance of $6.311 million in capital expenditures and $2.7 million in O&M expense for the CR&B project.

c. DTE Mobile Application Health.

For the DTE Mobile Application Health project, DTE is seeking $1.1 million capital and $0.17 million in O&M for the test year.[1042] Mr. Ambrose explained that the project is one of two projects that were combined and previously known, in Case No. U-21534, as Customer Digital Channels and Self-Service Program.[1043] He testified that the DTE Mobile App provides customers self-serve options for outage reporting, payments, and bill access, as well as some program management.[1044] Mr. Ambrose reported that 19%

[1040] See and Compare Exhibit A-24, Schedule N3, line 332 to Exhibit A-24, Schedule N3, line 80 in Case No. U-21534 (filing U-21534-0460).
[1041] Exhibit A-24, Schedule N3, line 80 in Case No. U-21534 (filing U-21534-0460).
[1042] 4 Tr 2270; Exhibit A-12, Schedule B5.7.2, line 19; Exhibit A-24, Schedule N3, line 338.
[1043] 4 Tr 2270.
[1044] 4 Tr 2270.

of all self-serve interactions in 2024 were completed using the DTE Mobile App, and 42% of all outage interactions were completed using the DTE Mobile App.[1045]

Describing the history of the DTE Mobile App, Mr. Ambrose testified that it was launched 14 years ago and underwent a rewrite using updated technology in 2023.[1046] Mr. Ambrose explained that the Company achieved a 2% increase in payments digital completion rate and a 3% increase in payments digital engagement rate since the rewrite.[1047] He testified that this project would fund operational monitoring, bug fixes, compatibility with new versions of mobile operating systems, performance optimization, security updates, and other minor enhancements in order to maintain key customer transactions and improve the digital self-service metrics.[1048]

Ms. Klocke recommended full disallowance of the requested costs for the project, explaining that despite the millions of dollars invested to rewrite the App in 2023, customer usage was at 19% of all self-serve interactions in 2024 and projected to be 20% in 2025.[1049] She also noted that the App includes the same features that are available on the Company's website.[1050] She concluded that even though the App has been available for 14 years, it is not a necessity for customers and no additional investment is warranted.[1051]

In rebuttal, Mr. Ambrose countered that while the App offers the same core functionality as the website, the Company offers the App for "convenience and

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[1045] 4 Tr 2270.
[1046] 4 Tr 2271.
[1047] 4 Tr 2271.
[1048] 4 Tr 2272.
[1049] 5 Tr 5119-5120.
[1050] 5 Tr 5119.
[1051] 5 Tr 5120.

comfort."[1052] He also clarified that the 19% Mobile App usage includes bill payments and other interactions using the App but when analyzed further, the usage rates show that 50% of all outage-related transactions are completed through the Mobile App.[1053] He also noted that in 2024, approximately 30% of customers used the App at least once and on average there were 300,000 to 350,000 active users per month.[1054] He further testified that Mobile App interactions have increased by 5% in the past three years.[1055]

In briefing, DTE maintains its objection to the full disallowance of the project and reiterated the points Mr. Ambrose made in his direct and rebuttal testimony to support its position.[1056] The Company further argues that the funding for the project is essential to maintain the App's core functionality and security.[1057]

Staff's brief recaps Ms. Klocke's testimony that the costs for the project should be disallowed because of the App's low usage rate and because customers can use the website to access the features that are available on the App.[1058] Staff adds that there is no evidence that the App will not be functional or secure without the requested funding.[1059]

This PFD does not find that the preponderance of the evidence establishes that there is a customer demand for this project. Instead, the record shows that, despite investment of millions in the App over 14 years, usage is at its highest rate of 19% and only predicted to increase to 20% for 2025. As stated by Staff, the App is not a necessity

[1052] 4 Tr 2369.
[1053] 4 Tr 2368.
[1054] 5 Tr 2369.
[1055] 5 Tr 2369.
[1056] DTE brief, 112-113; DTE reply, 85-86.
[1057] DTE brief, 112-113; DTE reply 86.
[1058] Staff brief, 87-89.
[1059] Staff brief, 89.

for customers and the proposed additional investment is also not necessary. Accordingly, this PFD adopts a disallowance of $1.101 million in capital expenditures and $170,141 in O&M expense for the Mobile App Health project.

d. Outage WISMO, PPS and Map Application Health.

The Company requests $3.0 million in the 2024-2025 bridge period and $5.3 million in the 2026 test period for its Outage Where-is-my-Order (WISMO) and Map Sustainment project as well as $1,700,001 capital and $525,000 in O&M costs for the test year for its Outage WISMO, Premise Power Status (PPS) and Map Application Enhancements project.[1060] These projects are collectively referred to as the Outage WISMO, PPS, and Map Application Health projects.

Mr. Ambrose explained that with the implementation of the Error Free Communications (EFC) – Outage Status initiative, WISMO, PPS, and the Outage Map, were developed to support the Outage Management and Storm processes.[1061] The Outage WISMO, PPS and Map Application Health projects will continue the migration of PPS into WISMO.[1062] The projects will also sustain the EFC Systems by implementing process changes and hardware upgrades, remediating defects, developing minor enhancements, and load-testing the Systems to simulate catastrophic storm scenarios (e.g., one million outages scenario). Mr. Ambrose testified that the projects will also provide funding to optimize the Outage Map load process and optimize the performance of and integration between the EFC systems and other systems like CR&B.[1063]

[1060] 4 Tr 2273; Exhibit A-12, Schedule B5.7.2, line 21; Exhibit A-24, Schedule N3, lines 343-344.
[1061] 4 Tr 2273.
[1062] 4 Tr 2274.
[1063] 4 Tr 2273.

Additionally, the projects would address security vulnerabilities by applying mandated patches and performing routine maintenance activities.[1064] And these projects will provide funding to maintain all outage reporting and status dashboards that are used daily and during storms.[1065]

Mr. Ambrose further testified that the Outage WISMO, PPS and Map Enhancements project is one of seven capital projects the Company intends to use to "Enhance Customer Interactions" by building upon and refining the prior improvements the Company made to the EFC processes and systems to optimize performance or other enhancements.[1066] Mr. Ambrose noted the Company is investing $2.2 million in 2026 test period capital to fund EFC Core System and Customer-Facing System enhancements that will continue to improve the key EFC metrics and the customer's outage experience.[1067]

Ms. Klocke explained Staff's recommended full disallowance of the requested costs for both the Outage WISMO, PPS and for the Map Application Health projects.[1068] Staff's recommended disallowance includes the following amounts: (1) for the Outage WISMO and Map Sustainment, $3.0 million in capital expenditures in the 2025 bridge year, along with $5.250 in capital expenditures in the test year, and $249,496 in test year O&M costs; and (2) for the Outage WISMO, PPS, and Map Enhancements, $1,700,001 in test year capital expenditures and $525,000 in O&M.[1069]

[1064] 4 Tr 2273-2274.
[1065] 4 Tr 2274.
[1066] 4 Tr 2300, 2310-2313; Exhibit A-12, Schedule B5.7.2; Exhibit A-24, Schedule N7.
[1067] 4 Tr 2314; Exhibit A-24, Schedule N7.
[1068] 5 Tr 5120-5121.
[1069] 5 Tr 5121.

Citing the history of the EFC and the Commission's order in Case No. U-21534, which required the Company to provide detailed status and expenditure updates for the EFC, Ms. Klocke testified that these projects directly correlate to the functionality of the EFC and additional funding should not be approved because the Company has not yet shown that it is meeting its stated goals for the EFC.[1070]

She further noted that the Company's identified values and benefits for these projects – "confidence that every customer is accounted for, accurate data for outage communications, consistent data to all endpoints and accurate restoration times" – are the same values and benefits that were offered for the EFC in Case Nos. U-21297 and U-21534.[1071] She opined that it is premature for the Company to receive $10 million for these projects when it has not yet shown how the $50 million approved in Case No. U-21534 for the EFC was utilized.[1072]

Mr. Ambrose explained in rebuttal that the requested recovery for the Outage WISMO, PPS and Map Application Health projects is different from the EFC funding requested in previous rate cases.[1073] He testified that the EFC systems have reached a state of development whereby sustainment is necessary and funding for these projects ensures that the supported technology is working as intended, performing at optimal levels, adapting to changes in business needs, and resilient during severe weather events.[1074] He also testified that the Outage WISMO, Premise Power Status (PPS) and Map Application Enhancements project builds upon the EFC capabilities while the Outage

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[1070] 5 Tr 5123-5125.
[1071] 5 Tr 5125-5126.
[1072] 5 Tr 5124-5125.
[1073] 4 Tr 2371.
[1074] 4 Tr 2371-2372.

WISMO and Map Sustainment focuses on stability, resiliency and optimization.[1075] He reiterated his direct testimony that the projects are necessary and expected to benefit customers.[1076] He further described the funding for the projects is non-discretionary and necessary to prevent a decline in performance of its customer communication systems.[1077]

Pointing to his direct testimony and Exhibit A-24, Schedule N7, Mr. Ambrose also countered that the Company has provided specific evidence on its expenditures for the EFC costs that were approved for recovery in Case Nos. U-21297 and U-21534 and that there is ongoing progress toward the long-term EFC system targets and goals.[1078]

DTE's brief emphasized the necessity of the 2025-2026 Outage WISMO, PPS and Map Application Health projects to sustain core EFC systems on an ongoing basis and to enhance the EFC system to meet increasing customer expectations.[1079] DTE also reiterated that it showed how EFC-related past expenditures were used and how it is meeting its goals from previous rate cases when it provided testimony and Exhibit A-24, Schedule N7 in this case that includes the total amount of capital being invested in the EFC core system components and customer-facing system workstreams and the improvements in the EFC metrics and customer outage experience realized to date.[1080] DTE argues that it is making progress on the long-term goals of the EFC initiative and continues to do so.[1081]

[1075] 4 Tr 2376-2377.
[1076] 4 Tr 2372-2375.
[1077] 4 Tr 2374-2375.
[1078] 4 Tr 2377-2379.
[1079] DTE brief, 114-116.
[1080] DTE brief, 115-116.
[1081] DTE brief, 117-119.

In its brief, Staff argues that DTE's request to fund these projects is premature and unreasonable. Staff notes that the U-21534 order, wherein the Company recovered over $50 million for the EFC, was issued just before this case was filed and questions whether the Company did its due diligence in estimating the costs for the EFC since it is already seeking an additional $10 million for certain elements.[1082]

In reply briefing, DTE reiterates its prior arguments, stating that the Commission "did not condition requests or approval of additional funds on any specific metrics or criteria to be met;" that the Company was only directed to "provide detailed status updates on any continuous improvements, as well as failures, in the EFC program and its various components."[1083]

Staff's reply brief reiterates its position that all costs for the Outage WISMO, PPS and Map Application Health project should be disallowed, and further emphasizes its skepticism of DTE's claim that the EFC system will lose functionality if these projects are not funded, because the EFC project itself is relatively new.[1084] Staff finds "no apparent reason that the project will experience an immediate decline without the requested funding from the instant case."[1085]

This PFD finds Staff's analysis persuasive and concludes that Staff's adjustments should be adopted. The Commission approved $52.4 million for the Company's EFC initiatives in Case Nos. U-21297 and U-21534.[1086] The Commission found it necessary, however, to monitor the results of the investments in the program when it required DTE

[1082] Staff brief, 92.
[1083] DTE reply, 87.
[1084] Staff reply, 5-6.
[1085] Staff reply, 6.
[1086] January 23, 2025 Order in Case No. U-21534, p 159.

to provide detailed status and expenditure updates in future rate cases and to meet with Staff biannually to provide detailed status updates on any continuous improvements or failures in the EFC program.[1087] There is no dispute that review of the EFC system progress is in the early stages and has not yet yielded any useful insight. And with so much already invested, this PFD agrees with Staff that it would be imprudent to allow additional recovery at this time. Consistent with the foregoing discussion, this PFD agrees with Staff and recommends a disallowance of $3.0 million for the Outage WISMO and Map Sustainment project in the bridge year, along with $5.250 in capital expenditures in the test year, and $249,496 in test year O&M costs. For the Outage WISMO, PPS, and Map Enhancements, this PFD recommends disallowance of $1,700,001 in test year capital expenditures and $525,000 in O&M expense.

e. Payment Merchant Fees.

Company witnesses Foley and Ambrose testified about the transaction costs associated with the processing of debit and credit card payments, known as Payment Merchant Fees. Mr. Foley, testified that the Company continues to believe that residential merchant fees are best recovered through base rates and noted that the Company's low-income customers have relatively high credit card usage (69% of payments are made using a credit card) compared to other residential customers (44% of payments).[1088] Mr. Ambrose further testified that disallowing the non-residential merchant fees in base rates would make accepting credit and debit card payments cost-prohibitive for a significant number of its customers who use that form of payment (1.4 million customers in 2024).[1089]

[1087] January 23, 2025 Order in Case No. U-21534, pp 160-161.
[1088] 4 Tr 2650.
[1089] 4 Tr 2316-2318.

He also expressed concern that the uncollectible expense would increase with the additional fee for using a credit card.[1090]

Mr. Foley testified that Merchant Fees, had historically been treated as an O&M expense and recovered through base rates but the Commission found it unreasonable to socialize the merchant fees in recent rate cases.[1091] Taking those recent decisions into consideration, Mr. Foley testified that the Company intends to charge customers who use a credit or debit card for payment a service fee to cover the merchant fee expense as part of a Payment Merchant Fee project.[1092] He stated that the projected test period cost of the project is $0 since DTE does not intend to generate a margin from the service fees but additional capital investment is necessary to enable the application of a service fee to customer bills.[1093]

Mr. Ambrose described the Company's plan for investing $10 million in the Payment Merchant Fee project which would fund a third-party consumer payment provider to process the credit/debit card payments for the non-residential customers who choose to use that form of payment and will not financially burden the non-residential customers who do not use a credit or debit card.[1094] He said that with the new payment system, the Company will have the flexibility to charge a fee or surcharge for customer card usage.[1095] Mr. Ambrose reported that a third-party provider for this project is a better option that the Company's internal payment platform because it allows for greater

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[1090] 4 Tr 2650.
[1091] 4 Tr 2646-2647, citing November 7, 2024 Order in Case No. U-21291, p 158 and January 23, 2025 Order in Case No. U-21534, p 232.
[1092] 4 Tr 2648.
[1093] 4 Tr 2648-2649.
[1094] 4 Tr 2317-2318; Exhibit A-24, Schedule N3, line 424.
[1095] 4 Tr 2317.

flexibility in the fee structure (flat fees vs percentage-based fees), reduced financial risk since the third party assumes the risk that the fees collected will cover the costs, enhanced customer experience, and access to advanced features (expanded payment method options like Venmo or PayPal, for example).[1096]

Mr. Ambrose also testified that most utility companies rely on third-party payment providers for transaction processing which suggests that this solution is reliable, secure, and scalable.[1097] Mr. Ambrose said the Payment Merchant Fees project will be completed in approximately 10-12 months (i.e., design, development, testing) and the Company expects to begin charging non-residential customers who use a credit/debit card a fee or surcharge by the end of the first quarter of the 2026 test period.[1098]

Regarding residential merchant fees, Mr. Foley proposed the Commission allow the Company to recover those fees in base rates for 2026 but direct the Company to not propose recovery of such fees in its next rate case; or authorize regulatory asset treatment of any residential merchant fees that are incurred: (1) after an order is issued in the instant case; and (2) before the Company is able to implement a solution to assess a fee directly to customers (including time for customer education), not to extend beyond 2026 with any regulatory asset associated with this approach addressed in a future rate case.[1099]

Ms. Klocke testified that although the merits of the Payment Merchant Fees program were not disputed, the "very high cost of nearly $10 million being requested to

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[1096] 4 Tr 2318-2320.
[1097] 4 Tr 2320.
[1098] 4 Tr 2320-2321.
[1099] 4 Tr 2650-2651.

implement it" was not sufficiently justified by the Company and should be fully disallowed.[1100] She noted that contractor costs for the project are over $8 million and despite the Staff's requests, the Company did not provide any information about how the contractor was chosen, alternative contractor costs, or an invoice from the contractor.[1101] She concluded that the Company failed to show that its requested costs are reasonable.

Mr. Ambrose objected to Staff's recommended disallowance in rebuttal, explaining that the contractors engaged in the project are the Company's long-standing business partners and have undergone thorough vetting to ensure they deliver a strong balance of quality and cost-efficiency. He testified that DTE chose contractors who are familiar with the Company's system to reduce implementation risk, shorten ramp-up time, ensure continuity across all areas: system integration, data migration, development, design, testing, and change management, and ensure the migration is secure, compliant and minimally disruptive to operations and customers. Mr. Ambrose testified that the high cost reflects the depth of the project and the number of systems and partners involved in its successful execution.[1102] He also said that the actual costs have been confirmed through executed contracts.[1103]

Mr. Ambrose and Mr. Foley also testified in rebuttal that DTE is withdrawing its request for recovery of residential merchant fees and is moving forward with the concurrent charging of fees to both non-residential and residential customers.[1104] Mr. Ambrose explained that implementing the change for non-residential and residential

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[1100] 5 Tr 5127.
[1101] 5 Tr 5127.
[1102] 4 Tr 2380.
[1103] 4 Tr 2381.
[1104] 4 Tr 2382-2383, 2675-2676.

customers concurrently streamlines the process, minimizes risks from multiple transitions, and facilitates a cost-effective execution.[1105]

DTE's brief relies on the points Mr. Ambrose provided in direct and rebuttal testimony to oppose the disallowance.[1106]

In its brief, Staff reiterated Ms. Klocke's testimony and also responds to the Company's rebuttal testimony regarding the qualifications of project contractors, contending that the Company failed to show that the costs of the project, in particular, were vetted.[1107] While Staff acknowledges that the Company provided its contractor's estimate with its rebuttal testimony, Staff nevertheless found it was too late for Staff to conduct an analysis of the costs.[1108]

In reply briefing, DTE contends that because Mr. Ambrose testified that the actual costs for the project have been confirmed through executed contracts, the Company has definitive information to substantiate its recovery request.[1109]

This PFD finds that DTE has not supported the reasonableness and prudence of the costs for this project. Staff reasonably expresses skepticism regarding the Company's due diligence in selecting, vetting, and approving the contractor costs – which are most of the costs for this project. DTE failed to provide a description of the alternatives it considered or any other evidence to corroborate its claim that its long-standing business partners were the most reasonable and prudent contractor choice for this project. Thus,

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[1105] 4 Tr 2380, 2382-2383.
[1106] DTE brief, 119-120.
[1107] Staff brief, 89-90.
[1108] Staff brief, 90.
[1109] DTE reply, 87.

this PFD recommends that Staff's proposed disallowance of $9.998 million of bridge period capital expenditures be disallowed.

f. Corporate Instance Maximo App Upgrade.

Turning to the Plant & Field Portfolio, the Company is seeking recovery for investment in several IT projects in the Return to Health category including, the Corporate Instance - Maximo Application Suite Upgrade Phase 1 project where they are seeking recovery of $8.2 million in test year capital expenditures.[1110]

Mr. Ambrose explained that Maximo is DTE's enterprise work and asset management platform and the Corporate Instance supports the Work Asset Management function for several business units within DTE including Distribution Electric Operations work and asset management.[1111] He testified that vendor support for the version of Maximo that the Company is using was scheduled to end in September 2025 but has been extended until 2026 and this project involves the planning and design phases for the newer version, which he states will require a complete re-platforming to accommodate new hardware and technical architecture.[1112]

Ms. Rogers explained Staff's recommendation to disallow $1.4 million in the test year for this project, testifying that the Company projected investing $3.749 million in 2025 for the Corporate Instance - Maximo Application Suite Upgrade in Case No. U-21534 and reported a $3 million variance in this case due to the deferral of the project into 2026.[1113] According to her, the amount requested in this case equates to more than what was

[1110] 4 Tr 2240.
[1111] 4 Tr 2231, 2240.
[1112] 4 Tr 2240-2241.
[1113] 5 Tr 5063-5064.

approved, plus the variance, and she recommends the Commission disallow $1.4 million based on that difference.[1114]

In rebuttal, Mr. Ambrose testified that the Commission disallowed a portion of what was requested in Case No. U-21534 for the project and the Company contends that the funding requirement will be $8.16 million in 2026.[1115]

Staff maintains its position in its brief and recommends the Commission disallow the 2026 test year costs for this project.[1116] Staff argues that DTE did not provide evidence to support 2025 and 2026 spend and therefore deferral of the project into 2026 should not change the scope of the investment.[1117]

DTE's initial and reply briefs reiterate the points presented by Mr. Ambrose.[1118]

This PFD finds that Staff's adjustment is reasonable and should be adopted. Mr. Ambrose does not establish that deferral of the project from 2025 to 2026 supports the Company's request to recover additional amounts for this investment, given past projections. Thus, this PFD recommends that Staff's $1.4 million test year adjustment be adopted.

g. Maximo Engineering Process Automation.

Among the projects included in the Strategic Category of the Plant & Field Portfolio, the Company is seeking to recover $4.9 million in the 2024 bridge period, and the historical spend of $5.4 million in 2023 for investment in the Maximo Engineering Process

[1114] 5 Tr 5064.
[1115] 4 Tr 2344.
[1116] Staff brief, 97-99.
[1117] Staff brief, 98-99.
[1118] DTE brief, 102; DTE reply, 93-94.

Automation project.[1119] Mr. Ambrose testified that the project will streamline the engineering and work management systems at Fermi by reducing manual tasks, improving reporting capabilities, and reducing technical complexity of managing multiple system interfaces.[1120]

Mr. Ambrose testified that the Company reports a variance of $4.2 million additional costs in 2023 and 2024 than was approved for recovery in Case No. U-21534 due to the disallowances of 10% in 2023 and 20% in 2024 directed by the order in that case, and because of a combination of additional scope of the Integrated Information Resource (I2R) Replacement added to this project and cost reallocation because implementation of the project that was originally scheduled for 2024 and 2025 was revised to 2023 and 2024.

Staff recommended disallowing $2.552 million in the bridge period for this project. Ms. Rogers testified that when the Company spent more than was approved in Case No. U-21534 on this project due to reallocating the costs to 2023 and 2024 instead of the original implementation plan of 2024 and 2025, it did so unnecessarily and imprudently.[1121] She pointed to the Company's claim that the reallocation was "aimed not only at expediting project delivery but also at achieving cost savings" but is unable to show quantifiable hard savings directly from the earlier implementation of the project.[1122]

Mr. Ambrose opposed the disallowance in rebuttal, testifying that there were no operational cost savings or sustainable reductions in nuclear operations expense for this

[1119] 4 Tr 2250; Exhibit A-12, Schedule B5.7.4; Exhibit A-24, Schedule N3, Lines 130, 131.
[1120] 4 Tr 2250.
[1121] 5 Tr 5065-5066.
[1122] 5 Tr 5065.

project but that was not DTE's basis for the expedited completion of the project.[1123] He stated that the project is a reasonable and prudent investment and reiterated his testimony that the project aligns with the Company's nuclear safety objectives and offers potential operational improvements.[1124]

In its brief, DTE again argues that the project is a reasonable and prudent investment that was implemented to enhance operating and human performance safety margins at Fermi 2.[1125] DTE contends that when it incurred the reallocation costs its goals were reasonable and to disallow those costs would inappropriately discount the strategic benefits that were achieved for the Company and its customers by modernizing engineering and work management systems as the Fermi 2 plant transitions to electronic work packages.[1126]

Staff maintains its position that the costs to move this project ahead one year were unnecessary and imprudent arguing that DTE is unable to show any quantifiable reduction in costs from this project or from the advancement of its implementation.[1127]

In its reply brief, DTE maintains its position that the decision to advance the project by one year was reasonable to achieve overall cost savings and argues that Staff's requirement of savings quantification should not be used to justify disallowance of this investment.

This PFD finds that DTE did not establish that accelerating the implementation of the project by one year was reasonable and prudent. DTE has not provided evidence to

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[1123] 4 Tr 2349.
[1124] 4 Tr 2348.
[1125] DTE brief, 103-104.
[1126] DTE brief, 104.
[1127] Staff brief, 95-97.

support its stated reason for the decision, (i.e. cost savings); in fact, it appears that earlier implementation in fact cost more. Therefore, the Company has not demonstrated this investment provides benefit to customers or is otherwise reasonable and prudent. Accordingly, this PFD adopts Staff's recommended disallowance of $2.552 million in 2024.

h. Backup Environmental Growth

According to Mr. Ambrose, the Backup Environmental Growth project within the Sustainment Category of the Infrastructure Operations Sub-portfolio of the Shared IT Portfolio, ensures IT devices managing DTE data have sufficient capacity for backup creation and secure storage. The Company is requesting recovery of $85,000 in the 2023 historical year, $0.498 million in the 2024 bridge year, $0.5 million in the 2025 bridge year, and $0.5 million in the 2026 test year.[1128]

Ms. Rogers testified that Staff recommends a disallowance of capital expenditures of $0.1 million in the 2025 bridge year, and $0.1 million in the 2026 test year because the Company projected higher capital costs than were actually spent in DTE's last two electric rate cases (Case Nos. U-21297 and U-21534).[1129] She explained that the Company spent less than projected in 2022, 2023, and 2024 and so, its request for capital expenditure for 2025 and 2026 should be reduced by 20%, or $0.1 million, in each year.

In rebuttal, Mr. Ambrose testified that the $0.5 million in capital expenditures that the Company is requesting for 2025 was adjusted based on its prior year's actual expenditures and the Company is on track to meet this target for the project.[1130] He also

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[1128] 4 Tr 2161; Exhibit A-12, Schedule B5.7.7, Line 2; Exhibit A-24, Schedule N3, Lines 198-201.
[1129] 5 Tr 5066-5067.
[1130] 4 Tr 2350.

explained that the Company expects to utilize the full requested amount of $0.5 million for 2026.[1131]

DTE's brief reiterates the points Mr. Ambrose made in his direct and rebuttal testimony. And Staff's brief reiterates its position that the disallowance is reasonable since the Company has a history of over-projecting costs for this project.[1132]

This PFD finds that Staff's adjustment is reasonable and should be adopted. As Staff notes, the Company has spent 80% (at most) of its projected costs on this project in the past three years. Given DTE's history of over-projecting this expenditure, a 20% disallowance of DTE's projection is reasonable and prudent. This PFD therefore adopts disallowances of $100,000 in 2025 and in 2026.

i. Network Hardening and Operations.

The Network Hardening and Operations project is also in the Sustainment Category of the Infrastructure Operations Sub-portfolio of the Shared IT Portfolio. Mr. Ambrose testified that it supports the Network Engineering services the Company uses for deployment of capital assets purchased under the Network End of Life (EOL) program.[1133] Mr. Ambrose described it as a "year-over-year project" that uses a third-party service provider to assess the Company's networks and implement operational system upgrades to fulfill the hardening requirements of network infrastructure required for a sustained quality of network services.[1134] The Company is seeking recovery of $0.881

[1131] 4 Tr 2350-2351.
[1132] Staff brief, 105.
[1133] 4 Tr 2165-2166.
[1134] 4 Tr 2166.

million in the 2023 historical year, $0.403 million in 2024 and $0.4 million in 2025, and $0.9 million in the 2026 test year for this project.[1135]

Ms. Rogers discussed Staff's recommended disallowance of $0.5 million in 2026, based on its analysis that found that despite the fact that the project investment has the same scope for 2024, 2025, and 2026, the Company projects spending $0.5 million more in 2026.[1136]

Mr. Ambrose's rebuttal testimony explained that the Company's projected costs for 2026 include a plan for substantial expansion in scope for the project in that year.[1137] He testified that in response to multiple large scale outages over the past year due to environmental and other issues impacting network communication, the Company will implement network redundancy such as dual paths, failover protocols, and out-of-band management, to reduce downtime risk and improve operational resilience at three critical sites.[1138] He stated that the activities planned for 2026 are complex, specific, necessary, and exceed the work done in 2024 and 2025 which results in increased costs.[1139]

DTE's brief relies on Mr. Ambrose's rebuttal testimony and states that the Commission should reject Staff's proposed $0.5 million disallowance to the Network Hardening and Operations project because it is based on Ms. Rogers' incorrect assumption that the 2026 project scope remains unchanged from prior years.

[1135] 4 Tr 2165; Exhibit A-12, Schedule B5.7.7, Line 9; Exhibit A-24, Schedule N3, Lines 221-224.
[1136] 5 Tr 5068-5069.
[1137] 4 Tr 2351-2352.
[1138] 4 Tr 2352-2353.
[1139] 4 Tr 2353.

In its brief, Staff argues that the scope of work that DTE described for 2024, 2025, and 2026 through Staff's audit was nearly the same in each year.[1140] Staff contends that its analysis is limited by the information provided by the Company and that information is different from what Mr. Ambrose testified to in rebuttal.[1141] Staff further argues that providing information in rebuttal does not allow time for Staff review.[1142] Staff also suggests that an initial analysis of Mr. Ambrose's rebuttal testimony about this project does not justify the Company's entire $0.9 million request for the project in 2026, since Mr. Ambrose detailed work with a projected cost of $0.5 million.[1143]

This PFD finds that Staff's adjustment should be adopted. Although DTE argues for the first time in rebuttal that it expanded the scope of the project for 2026, this PFD agrees with Staff that it is DTE's responsibility to provide evidence for all requested expenses in its direct case, and the additional projected costs for 2026 were provided too late in the proceeding to allow for proper review. Instead, the record shows that the activities DTE planned to complete with this project in 2024, 2025, and 2026 were essentially the same. For these reasons, this PFD finds that the recovery of costs for each year should be the same and recommends a disallowance of $0.5 million for 2026.

j. Digital Worker Experience Electric End-of-Life.

Under the Return to Health Category of the Shared IT's Infrastructure Operations Sub-portfolio, Witness Ambrose testified that the Company is investing in seventeen projects, including the Digital Worker Experience Electric End-of-Life (EOL) project. For

[1140] Staff brief, 107.
[1141] Staff brief, 108.
[1142] Staff brief, 108.
[1143] Staff brief, 107-108.

this project the Company is seeking recovery of $2.782 million in the 2023 historical year, $5.021 million in 2024, $2.650 million in 2025, and $1.621 million in the test year.[1144]

Mr. Ambrose described the project as an "annual investment" to replace EOL endpoint devices like laptops, desktops, tablets, and smart devices which degrade after five years but are used by DTE employees to access DTE systems, communications, and data.[1145] Mr. Ambrose explained that the Company is seeking a variance of $2.7 million more than what was approved for cost recovery in Case No. U-21534 due to the disallowances in that case and because the Company is adding additional students and storm restoration workers.[1146]

Ms. Rogers initially recommended a disallowance of $1.563 million in the 2023 historical year, $2.825 million in 2024, $1.209 million in 2025, and $0.789 million in the 2026 test year.[1147] She testified that through Staff's audit of the number and cost of the devices that will be replaced with this project, it found a discrepancy in what the Company seeks for projected capital and its calculations for the equipment, as reflected in Exhibit S-12.2.[1148]

In rebuttal, Mr. Ambrose testified that Ms. Rogers miscalculated some of the amounts, and she failed to include all labor costs required for the project.[1149] Mr. Ambrose also objected to disallowing costs for 2023, 2024, or 2025 for this project, because the

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[1144] 4 Tr 2171; Exhibit A-12, Schedule B5.7.7, Line 16; Exhibit A-24, Schedule N3, Lines 241-244.
[1145] 4 Tr 2171.
[1146] 4 Tr 2172.
[1147] 5 Tr 5070.
[1148] 5 Tr 5070-5071.
[1149] 4 Tr 2340-2343

Commission approved those costs in Case No. U-21534 and to disallow a portion of the costs in this case amounts to a reversal of the Commission's prior order.[1150]

In its brief, DTE relies on Mr. Ambrose's rebuttal testimony that no disallowance of costs for this project is justified.

Staff's brief provided a modified disallowance recommendation of $1.596 million in 2025 for additional labor costs that are in excess of those approved in the U-21534 order, and $0.215 million in 2026 for overhead (discussed below).[1151] Staff acknowledged that it overvalued the initial amount requested for 2024 and corrected its calculation.[1152] Accepting Mr. Ambrose's rebuttal testimony related to the costs and quantities of the devices at issue, Staff also conceded to DTE's requested recovery for those costs.[1153] Regarding the labor costs, Staff revised its calculations to include the Company's full projected labor costs for 2023 and 2025.[1154] Staff's brief objected to DTE's requested labor costs for 2024 because it was more than what was approved for labor in Case No. U-21534 and recommends the excess labor costs be disallowed.[1155]

DTE's reply brief maintains its position that the requested costs should be recovered without any disallowance.[1156]

The categorical cost disallowance recommended in other sections of this PFD aside, this PFD recommends the Commission disallow the 2024 labor costs that exceed

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[1150] 4 Tr 2343.
[1151] Staff brief, 108-111.
[1152] Staff brief, 109.
[1153] Staff brief, 109-110.
[1154] Staff brief, 110.
[1155] Staff brief, 110.
[1156] DTE reply, 97-99.

those which were approved by the Commission in Case No. U-21534 but otherwise approve the requested costs for this project.

k. Field Worker Device End of Life

Another project under the Return to Health Category of the Shared IT's Infrastructure Operations Sub-portfolio, is the Field Worker Device EOL project, which Mr. Ambrose described as the annual replacement of enterprise Mobile Data Terminal (MDT) devices which are the computerized devices used on mobile devices (devices in transit or devices that are mounted on systems that are always on the move) to communicate with the centralized control system.[1157] According to him, the MDTs provide maps, geographic locations, and other information to field workers and customer service representatives and the current fleet of MDTs are experiencing multiple device and connectivity failures.[1158] The Company is seeking recovery of capital expenditures of $0.902 million in 2024, $0.9 million in 2025, and $0.9 million in the test year for this project.[1159]

Ms. Rogers discussed Staff's recommended disallowance of $0.135 million in 2026.[1160] She testified that although the Company is seeking the same costs for 2024, 2025, and 2026, the number of MDTs that the Company plans to replace decreases over the three years.[1161] Referencing Exhibit S-12.11, p 7, Ms. Rogers explained that when

[1157] 4 Tr 2175.
[1158] 4 Tr 2175.
[1159] 4 Tr 2175; Exhibit A-12, Schedule B5.7.7, Line 19; Exhibit A-24, Schedule N3, Lines 252-254.
[1160] 5 Tr 5072.
[1161] 5 Tr 5072.

Staff compared the number of devices that the Company said it replaced each year, with the actual cost for device replacement, it found a difference in costs for 2025 and 2026.[1162]

Mr. Ambrose testified in rebuttal that while the device count decreased each year, the per unit material and labor costs increased, and therefore the total cost was the same each year.[1163] He stated that the Company's cost projections for this project account for changes in market prices, expected usage and operational complexities and no portion should be disallowed.[1164]

DTE's brief relies on Mr. Ambrose's rebuttal and argues that the Commission should reject Staff's recommended disallowance because the Company's cost projections for the Field Worker Device EOL project reflect anticipated increases in labor and equipment expenses over time, which Staff's calculations overlooked.[1165]

Staff's brief argues that DTE has not justified the accuracy of Mr. Ambrose's rebuttal testimony. Staff points out that according to Mr. Ambrose, the Company is factoring in a 6% change in the cost of equipment and labor between 2024 and 2025, and a 10-11% increase between 2025 and 2026.[1166] Staff argues these projections are arbitrary and should not be approved.[1167]

This PFD finds Staff's analysis persuasive and concludes that the recommended adjustment should be adopted. This PFD finds that DTE has not supported the

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[1162] 5 Tr 5072-5073. Staff recommends an overall disallowance for this project that is discussed further in the "Projects with Level 3 Cost Estimates" subsection below and which addresses the 2025 cost discrepancy.
[1163] 4 Tr 2346.
[1164] 4 Tr 2346-2347.
[1165] DTE brief, 105-106.
[1166] Staff brief, 112-113.
[1167] Staff brief, 113.

reasonableness and prudence of its projections, noting that the Company is seeking the same costs for 2024, 2025, and 2026 for this project and that the cost of the project is "based upon the number of field worker devices planned to be replaced in a given year."[1168]

As Staff argues, it is reasonable for the costs of the project to decrease because the number of devices being replaced is decreasing each year.[1169] Further, this PFD finds that it was not until rebuttal did DTE disclose that it is expects labor and material costs for 2025 and 2026 to increase by a significant percentage. Not only does this PFD agree that the labor and inflation increase the Company claims is arbitrary, but this PFD also finds that DTE's self-serving witness testimony does not sufficiently justify recovery of the full amount it seeks. Consistent with the foregoing, this PFD adopts Staff's disallowance of $135,000 in the test year.

l. Distribution Operations Productivity Center

In the Strategic Category of the Enterprise Data Analytics Sub-Portfolio of the Shared It Portfolio, the Company is seeking to invest in the Distribution Operations (DO) Productivity Center project which the Company describes as a six-month investment designed and implemented to provide a "sufficiently accurate picture of productivity and performance for Blue Sky and Grey Sky work" by creating a central reporting location and providing consistent productivity metric measurement across DO.[1170] The Company is seeking to recover $0.4 million for 2024 for this project.[1171]

[1168] Exhibit S-12.11, p 6.
[1169] Exhibit S-12.11, p 6.
[1170] 4 Tr 2198.
[1171] 4 Tr 2198; Exhibit A-12, Schedule B5.7.8, Line 3; Exhibit A-24, Schedule N3, Line 313.

Ms. Rogers explained that Staff recommends complete disallowance of the capital expenditure for this project.[1172] She noted that the Company provided no evidence that the project would reduce costs or increase safety or reliability for customers.[1173] She also noted that the Company gave the project a Project Prioritization Score (PPS) of 2.2 out of 9 which meant that the project aligns with only two of the Company's priorities and may have a small impact on the categories of strategic alignment, customer experience, employee engagement, affordability, cost benefit, operational reliability, and foundational capability, but will not have a large or substantial impact on any category.[1174]

Ms. Rogers also noted that the project was implemented from April 2024 through September 2024, but it was not included in the Company's previous rate case.[1175] Ms. Rogers described the project as "nice to have," but "not a necessity" and therefore found it imprudent and unreasonable to pass on the costs to ratepayers.[1176]

Opposing Ms. Rogers' testimony, Mr. Ambrose testified that the DO Productivity Center project is a prudent and essential investment that enhances operational efficiency, safety, and reliability.[1177] He stated that the project directly benefits customers because it improves utility performance in ways that positively impact service quality and reliability, equips field crews with a Situational Awareness Dashboard that centralizes real-time data, identifies operational inefficiencies, and supports standardized process improvements, and provides a provides a comprehensive and accurate view of

[1172] 5 Tr 5074.
[1173] 5 Tr 5074.
[1174] 5 Tr 5074-5075.
[1175] 5 Tr 5075.
[1176] 5 Tr 5074-5075.
[1177] 4 Tr 2354.

productivity and work execution across operations, addressing critical process and data gaps that limit visibility and efficiency improvements.[1178]

DTE's brief relies on Mr. Ambrose's direct and rebuttal testimony to support recovery of the costs for the project and further argues that the project results in faster restoration times, reduced rework, and enhanced safety, all of which improve the customer experience.[1179]

In its brief, Staff maintains its recommendation to disallow the expenses associated with the DO Productivity Center project.[1180] Staff argues that the Company failed to support its claim that the project increases reliability, safety or that it provides cost savings.[1181] Staff also argues that the project seems to have been implemented with urgency, and despite the PPS of 2.2, DTE does not explain why this was so.[1182]

In reply briefing, DTE objects to Staff's contention that because the costs for the project were not included in Case No. U-21534, there was a lack of planning on the Company's part.[1183]

This PFD finds that DTE has not supported the reasonableness and prudence of this project or supported its cost projections. As Staff observes, the project received a prioritization score of 2.2, and DTE did not provide a BCA for review. The Commission has requested detailed support for individual IT projects, including quantified project

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[1178] 4 Tr 2354-2355.
[1179] DTE brief, 106.
[1180] Staff brief, 114-115.
[1181] Staff brief, 114.
[1182] Staff brief, 114.
[1183] DTE reply, 101.

benefits and explanation of the project timeliness, in the last few rate cases.[1184] This PFD finds that the evidence DTE provided does not comply with the Commission's instructions. Without this information, this PFD finds that the project is not ripe for funding. Indeed, the Company itself has assessed the project as a low priority for implementation given its project prioritization score of 2.2. Thus, this PFD adopts a disallowance of $439,000 for 2024.

m. Information Protection Security

As shown in Exhibit A-12, Schedule B5.7, page 1, line 6, capital expenditures for Information Protection Security (IPS) total $4 million for the 2023 historical year, $13.4 million in the 24 month bridge period and $6.5 million for the projected test period. DTE is also requesting $283,000 in test year O&M.

Mr. Ambrose presented Figure 6 at 4 Tr 2144, which provides a high-level depiction of the five spend areas within the IPS portfolio (Regulatory Compliance, Return-to-Health, IT Enhancements, Strategic, and IT Projects less than $250,000).

Ms. Zichi recommended a total disallowance, or $186,000 in 2025 and $184,000 in 2025, in capital expenditures for the Communication Compliance and Data Loss Prevention (DLP) Diversification project, along with $283,000 in test year O&M. Referencing Exhibit S-18.0, pp. 1-3, Ms. Zichi testified that in response to an audit request, DTE indicated that it currently has both systems implemented and is looking to expand coverage. In follow-up, Staff asked whether DTE is experiencing any issues with data loss, which Staff maintains "could support the need to complete this project now."[1185]

[1184] May 8, 2020 Order in Case No. U-20561, pp 152-153; December 1, 2023 Order in Case No. U-21297, pp 143-166.
[1185] 5 Tr 5133.

Noting that DTE did not report any data loss issues, Ms. Zichi testified that the Company failed to justify the need for the project or why it needs to be done now.[1186] Further, she observed that DTE did not explain why the current system and coverage are inadequate, adding that DTE was unable to identify any benefits to the project expansion, although the project does have some new features. Alternatively, if the Commission does not adopt the full disallowance for this project, Staff recommends a full disallowance of all overhead costs associated with the Communications Compliance and DLP Diversification Project.[1187]

In rebuttal, Mr. Ambrose disagreed with Staff's recommendation, noting that "the Company's operational environment has advanced rapidly" over the past year and a half, and that the project is intended to expand coverage to newer platforms such as cloud applications, email, message chats and various Microsoft applications.[1188] Mr. Ambrose explained that "it is essential to implement Microsoft Communication Compliance and Data Loss Prevention across all platforms, including email, Teams, Viva Engage, SharePoint, and OneDrive, in order to prevent sensitive data exposure and ensure regulatory compliance."[1189] As such, Mr. Ambrose recommended that Staff's disallowance be rejected.

In briefing, DTE reiterates that the Company is not replacing existing systems, noting that its current system covers internal and on-premises, but it needs to be expanded to cover new applications and platforms.[1190]

[1186] 5 Tr 5133-5134, Exhibit S-18.0 pp. 4-5.
[1187] 5 Tr 5134.
[1188] 4 Tr 2356.
[1189] Id.
[1190] DTE brief, 107.

Staff responds to Mr. Ambrose's rebuttal, noting that it never questioned whether or not the new system was intended to replace an existing one, and was not the basis for Staff's disallowance. Nor did Staff take issues with the features of the project. According to Staff:

> The Company seems to address two separate systems in rebuttal. From the Company's initial filing it shared coverage would be extended to cloud applications, which encompasses areas like outbound emails, Teams, message chats, one Drive SharePoint, Copilot and channel communication. Similarly, in rebuttal the Company stated these same programs would be receiving the extended coverage and did not provide any additional information. (4 TR 2356.) The Company then shares new information pertaining to additional applications that were installed in the last 12 to 18 months that are part of the Company's operational environment. It further states that due to these additional applications being implemented the current security barrier does not fully cover this new landscape. (*Id*.) It is unclear how these new applications installed relate to the other cloud applications initially identified by the Company as needing extended communication compliance and data protection coverage. Additionally, if these applications, that were installed 12 to 18 months ago, are no longer protected, why was this lack of coverage not addressed immediately? If having complete security coverage was not a priority 12 to 18 months ago when the Company first installed these new features, it is unclear why it is important now.[1191]

Staff further expresses concerns regarding the limited information provided in DTE's audit responses and rebuttal testimony, arguing that the information provided in audit and in rebuttal testimony "address the issues of compliance but does not provide concrete information as to whether the Company would violate compliance if this project was not completed now."[1192] Staff reiterates that if compliance were in fact a significant concern, the Company would have addressed it in audit.

[1191] Staff brief, 101.
[1192] Staff brief, 102.

Staff concludes that DTE has still not provided sufficient information to demonstrate that the Communication Compliance and DLP Diversification project is required to be undertaken now.

In its reply, DTE maintains that the information it provided in audit and rebuttal testimony were not inconsistent, and "[r]egarding compliance and the lack of issues to date, the Company is seeking these funds to expand this program to ensure that it continues to protect its operational environment; requiring evidence of a violation or other problem before approving recovery applies an unreasonable and not useful standard to the cost recovery request."[1193]

This PFD agrees with Staff that the Company failed to provide sufficient information in its audit responses to permit recovery of the costs for the Communications and DLP Diversification at this time. A review of Exhibit S-18.0 shows that Staff progressively asked for more detailed information on the project, and DTE's response, particularly with respect to compliance issues is vague, mentioning the need to "strengthen sensitive data protection, mitigate compliance risks, improve the organization's overall security posture," also suggesting that the system would "ensure organizational compliance with applicable standards, such as Payment Card Industry Data Security Standard[.]"[1194] It was not until Mr. Ambrose's rebuttal that DTE raises operational necessity, risk exposure, and the potential penalties for non-compliance across external platforms.[1195]

[1193] DTE reply, 95.
[1194] Exhibit S-18.0 p. 6.
[1195] 4 Tr 2357.

This PFD also finds persuasive Staff's concerns that despite an "operational environment that has advanced rapidly over the last 12 to 18 months" DTE waited until 2025 to begin this expansion to external applications and platforms, despite the alarm bells raised in Mr. Ambrose's rebuttal. Thus, this PFD finds that for now, 2025 and 2026 capital expenditures of $186,000 and $184,000 should be disallowed, along with $283,000 in test year O&M expense.

i. Projects with Level 2 Cost Estimates

Mr. Ambrose explained the Company's process for identifying and prioritizing IT investment projects.[1196] He testified that as part of its annual planning cycle, IT project activities occur in various phases from "Submitted" to "Approved" and appropriated for investment.[1197] According to him, beginning in 2025, all projects that reach the "Qualified" phase are required to undergo a "Level 2" cost estimate which is used for detailed project control and near-final decision making.[1198] Mr. Ambrose explained that the Level 2 cost estimate has an accuracy range of -15% to +20%.[1199] Thereafter, a project undergoes "project prioritization" scrutiny to determine whether it has the highest return on investment and aligns with the Company's key IT drivers.[1200]

Staff recommends a 20% disallowance of costs for 5 of the 8 IT projects with Level 2 cost estimates in this case resulting in an adjustment of $0.685 million in the 2026 test year as well as $16,000 in O&M.[1201] Ms. Rogers described projects with the Level 2 cost

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[1196] 4 Tr 2125-2129.
[1197] 4 Tr 21-25-2126.
[1198] 4 Tr 2127.
[1199] 4 Tr 2127.
[1200] 4 Tr 2127.
[1201] 5 Tr 5051-5054.

estimates as “immature and imprecise” since the Level 2 cost estimate is conducted years before a project is implemented, and there may be changes to the scope of the investment, timeline and priority for execution, and the level of necessity for the project before execution can occur.[1202]

Ms. Rogers further supported a 20% disallowance of costs for these projects based on Staff’s review and determination that 50 projects had a different cost because the scope or timeline changed.[1203] She also found that the Company over-recovered on 64% of the projects with a Level 2 cost estimate in Case No. U-21297 that had actual costs and under recovered on 36% of those investments as shown in Exhibits S-12.4, S-12.5, and S-12.6, which was much different than the Company’s report that the accuracy of Level 2 cost estimates is -15% to +20%.[1204] Ms. Rogers testified that the 20% disallowance is conservative because DTE’s average percentage of overrecovery on projects with Level 2 cost estimates is 40%.[1205]

Ms. Rogers explained that Staff compared the Level 2 cost estimates to the AACE Cost Estimate Recommended Practice (RP) No. 17R-97, which she described as a classification methodology for estimating project costs across all industries, and found the Level 2 cost estimate comparable to the AACE Class 3 estimate. She testified that the purpose of both the DTE Level 2 cost estimate and the AACE Class 3 estimate is budget authorization, and the accuracy range for the AACE Class 3 estimate is +20% to -30%.[1206]

[1202] 5 Tr 5050, 5052.
[1203] 5 Tr 5052.
[1204] 5 Tr 5053.
[1205] 5 Tr 5054.
[1206] 5 Tr 5054-5055.

Witness Rogers further testified that the 20% disallowance is consistent with Staff's recommendations in the most recent rate cases, which were approved by the Commission, in Case Nos. U-21534, U-21297, U-20836, and U-21291.[1207]

In rebuttal, Mr. Ambrose opposed the 20% disallowance recommendation, testifying that the Level 2 cost estimates for IT projects are comprehensive and developed through input and reviews from IT subject matter experts with practical knowledge and experience with the Company's IT needs.[1208] Mr. Ambrose stated that Ms. Rogers was incorrect in describing the projects with Level 2 estimates as "immature and imprecise" and countered that changes to costs that occur post-estimate are due to legitimate changes in the scope or requirements of the project and are a "natural consequence of the project design and execution process" and not due to a flaw in the initial estimate.[1209]

Referencing Mr. Robertson's testimony and Exhibit A-34, Schedule Y-2, Mr. Ambrose reiterated the Company's position that using the AACE RP No. 18R-97 for IT project cost estimation is inappropriate. And Mr. Ambrose opined that taking a position in a case simply because the same position was taken in a previous case is not sufficient justification for a disallowance.[1210]

DTE's brief reiterates its argument that the Commission should reject the capital disallowances proposed by Staff that pertain to Level 2 cost estimates based on the points Mr. Ambrose provided in direct and rebuttal testimony.[1211]

[1207] 5 Tr 5054-5056.
[1208] 4 Tr 2332-2334.
[1209] 4 Tr 2333.
[1210] 4 Tr 2333.
[1211] DTE brief, 97-98.

Staff's brief reiterates its recommendation for the disallowance and further pointed to the fact that changes have occurred in 50 of the projects for which the Company is currently seeking recovery. Staff concludes that this demonstrates that complete reliance on Level 2 cost estimates is premature, not because of who or how the estimate was developed but because of how far ahead of execution the estimate is developed.[1212] Staff notes that it used AACE 17R-97 methodology, not AACE 18R-97, and concluded that a Level 2 cost estimate align closest with the AACE Class 3 estimate.[1213]

Staff also contends that because the Commission is unable to order reimbursement to customers if the full amount is not spent on a project, but the Company is nevertheless able to recover in its subsequent rate case any additional reasonable and prudent costs, a disallowance is fair. And Staff argues that the recommended disallowance is prudent, not just because it was taken in a previous case, but because a Level 2 cost estimate proves to be imprecise in this case just as it did in the prior case, and contrary to the Company's stated range for its accuracy.[1214]

This PFD finds that Staff's disallowance is reasonable and supported by the evidence in the record for this case. Regardless of whether the Level 2 cost estimates are developed by subject matter experts, DTE does not offer evidence to disprove the cost variances pointed out by Staff, and instead admits that cost changes are the result of changes to the scope and requirements of a project after the Level 2 cost estimate is complete which it describes as a "natural consequence of the project design and execution process." This PFD recognizes that project cost estimates are temporary by

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[1212] Staff brief, 75.
[1213] Staff brief, 76.
[1214] Staff brief, 76-77.

nature and must start somewhere. However, as stated by Staff and affirmed in prior cases with similar information, costs cannot be properly evaluated by the Commission for inclusion in rates at the Level 2 cost estimate phase. And there is no evidence to contradict the Staff's rationale for using the AACE Class 3 Estimate to derive its 20% disallowance.

ii. Projects with Level 3 Cost Estimates

Mr. Ambrose testified that projects meeting the Company's Level 3 criteria are subsequently reviewed by DTE executives within the Company's Technology Investment Committee (TIC).[1215] If approved by the TIC, a "Level 3" detailed cost estimation is performed. Witness Ambrose testified that the Level 3 estimate has an accuracy range of -10% to +15%.[1216]

Staff Witness Rogers testified that of DTE's 202 IT projects with Level 3 cost estimates in this case, Staff proposes that each receive a 10% disallowance which totals $13.077 million in the 2025 bridge period, $11.367 million in the 2026 test year, and $2.488 million in test year O&M expense.[1217]

Referencing Exhibits S-12.4 and S-12.8, Ms. Rogers described the Level 3 cost estimates as inaccurate in nature given her calculation that the actual costs of 77 of the 159 projects (48% of the projects) with a Level 3 estimate in Case No. U-21534 resulted in over recovery of 34% of costs, and under recovery of 45% occurred for 73 projects (46% of the projects) compared to the Company's stated accuracy of -10% to +15%.[1218]

[1215] 4 Tr 2127-2128.
[1216] 4 Tr 2128.
[1217] 5 Tr 5056.
[1218] 5 Tr 5057.

Ms. Rogers opined that the difference in actual versus projected costs occurs because a project's scope and/or timeline changes after undergoing a Level 3 cost estimate since the estimate is completed over a year before the project is implemented.[1219]

As with Level 2 cost estimates, Ms. Rogers compared DTE's Level 3 cost estimates to the AACE RP No. 17R-97 and found the Level 3 cost estimate comparable to the AACE Class 2 estimate which have an accuracy range of +10% to -15%.[1220] Ms. Rogers also noted that Staff recommended a 10% disallowance of costs for IT investments with Level 3 cost estimates in DTE's last electric rate case, Case No. U-21534, and the Commission approved the disallowance.[1221]

In rebuttal, Mr. Ambrose disagreed with the recommended disallowance, stating that the Level 3 estimates are "accurate and comprehensive at their point of development," but reported that it is widely accepted that scope changes during execution will occur and account for subsequent cost updates.[1222] He testified that variances between the Level 3 estimates and the finalized actual costs are expected.[1223] Mr. Ambrose found Staff's analysis, as presented in Exhibit S-12.8, to be "incomplete, unstructured," and inconsistent with the widely accepted practice to evaluate cost estimates over the full project lifecycle, and not year by year.[1224]

Mr. Ambrose further explained that 31 of the projects with an over-recovery "occurred within the two-year timeframe, which may not reflect the entire project

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[1219] 5 Tr 5058.
[1220] 5 Tr 5058.
[1221] 5 Tr 5059.
[1222] 5 Tr 2335.
[1223] 5 Tr 2335.
[1224] 5 Tr 2335.

lifecycle[.]"[1225] He reasoned that the variances were due to changes in the scope of the projects to adjust and align with other projects due to execution synergies, technical dependencies and business values, efficiency gains or cost-savings because of successful vendor negotiations, technical solution re-designs, utilizing existing solutions/resources, and effective resource planning, and schedule changes.[1226] Mr. Ambrose also testified that 14 of the projects with Level 3 cost estimates are associated with multi-year projects and should not be counted separately in the analysis.[1227]

In its brief, DTE again argues that its Level 3 cost estimates are accurate and comprehensive at their point of development, supporting project requirements and initial budget decisions, and that any variances between the Level 3 cost estimates and finalized costs are justified changes to the scope of a project prior to execution and not due to estimation errors.[1228] DTE describes Staff's analysis of judging the accuracy of DTE's projected expenditures solely on annual spend as incomplete, unstructured, misleading and inconsistent with the widely accepted practice for calculating estimate-to-actual variances for a project.[1229]

DTE argues that when comparing planned and actual expenditures over the entire period (2023 and 2024) for 77 of its projects with Level 3 cost estimates, under-recovery greater than 10% occurred for 6 projects, and over-recovery greater than 10% occurred for 31 projects.[1230] DTE further argues that because 25 of those 31 projects with over

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[1225] 4 Tr 2336.
[1226] 4 Tr 2336-2337.
[1227] 4 Tr 2336 citing Exhibits S-12.8 and A-44, Schedule JJ2.
[1228] DTE brief, 97-98.
[1229] DTE brief, 98.
[1230] DTE brief, 99.

recovery have not completed the entire project life cycle, the over-recovery is not indicative of poor estimation accuracy.[1231]

In its initial brief, Staff argues that Level 3 cost estimates are inaccurate in nature and maintained its position that the Commission should disallow 10% of the costs associated with projects with Level 3 cost estimates.[1232] Staff does not dispute that the Company's use of Level 3 cost estimates is appropriate for internal initial budget decisions but objects to passing the full Level 3 costs onto ratepayers.[1233] Staff further argues that even if the scope changes that occur as part of project estimation and management practice, it is inappropriate for ratepayers to pay the full costs and cites its calculations that DTE either over recovered or under recovered, and by much more than 10%, on the majority of the projects with an Level 3 cost estimate in its last rate case.[1234] Staff also notes that DTE only applied its two-year methodology for calculating the accuracy of its Level 3 projected expenditures to the 77 projects where Staff found the Company over-recovered, and that the 73 projects with under recovery may be subject to change as well.[1235] Even considering the Company's calculations for the 77 projects, Staff notes that the Company over recovered on 34% of the projects, and there are 3 additional projects that were greatly over recovered on, but the Company listed no variance because the projects were merged with the CR&B project.[1236] Staff opines that irrespective of the reasons the Company claims the over-recovery occurred, it is unfair for ratepayers to pay

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[1231] DTE brief, 99.
[1232] Staff brief, 77-80.
[1233] Staff brief, 77-78.
[1234] Staff brief, 78.
[1235] Staff brief, 79.
[1236] Staff brief, 79-80.

those costs. Staff argues that it is reasonable to disallow 10% of the Level 3 cost estimates in this case, and for the Company to seek recovery in the next rate case if it spends more, instead of possibly allowing the Company to earn a return of and on expenditures that were spent imprudently or were not incurred for what they were intended.[1237]

In its reply brief, DTE relies on Mr. Ambrose's testimony to reiterate that disallowance is inappropriate, and the Company further argues that Staff repeats its recommendation for a 10% disallowance for projects with Level 3 cost estimates in this case as it did in previous cases, but does not account for the refinements to the Company's IT capital investment planning process, specifically its revised IT project estimation requirements, that have been made since the 2024 rate case.[1238]

Staff also replies to the Company's argument for IT projects with Level 3 cost estimates by reiterating its position for disallowance and emphasizing that its recommendation for a 10% disallowance is conservative compared to AACE Class estimate recommendations and the variance in projected versus actual spending for the Company's past projects with Level 3 cost estimates.[1239]

This PFD finds that Staff's adjustment should be adopted. Again, this PFD recognizes that project cost estimates are temporary by nature and project changes may occur over time. This PFD is not convinced, however, that the Commission should rely on the Level 3 cost estimates for ratemaking purposes when this record shows that the Company greatly over- or under-estimates the costs of most of the projects at the Level

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[1237] Staff brief, 80.
[1238] DTE reply, p 79.
[1239] Staff reply, 6-8.

3 cost estimate phase in the last rate case even when it made its best effort to create an accurate Level 3 cost estimate at "the point of development."[1240] Consistent with Commission's decision in Case No. U-21534, this PFD recommends the Commission find it "unfair to pass costs onto ratepayers without the assurance that its entirety will be used for the intended reasonable and prudent investment."[1241] This PFD therefore adopts Staff's recommended IT disallowances for Level 3 cost estimates for IT projects.

iii. Projected Overhead & Other Costs (Capital)

Referencing DTE Exhibit A-24, Schedule N3, Column X, Staff Witness Rogers recommended the Commission disallow the "Projected Overhead and Other Costs (Capital)" for all IT projects with spending that was not already approved in Case No. U-21534 and for which Staff was not already recommending a full or partial disallowance. This recommended disallowance amounts to $0.731 million in 2023, $0.284 million in 2024, $2.947 million in 2025, and $11.542 million in the test year.[1242]

Ms. Rogers testified that the Company has not provided adequate evidence to justify the "Projected Overhead and Other Costs (Capital)" expense since despite multiple audit requests, DTE never provided specific information about the purpose of each cost.[1243] She also explained that for the existing projects, she expected the Company to offer a contract, receipt, or breakdown of the costs and which dollars applied to the "Projected Capital Overhead and Other Costs (Capital)" category but did not receive that

[1240] 4 Tr 2335.
[1241] January 23, 2025 Order in Case No. U-21534, p 186.
[1242] 5 Tr 5060.
[1243] 5 Tr 5060-5061.

information when it was requested.[1244] She concluded that the costs were either "uncertain," "arbitrary," or "unjustified" and should not be passed on to ratepayers.[1245]

To avoid overlap between this recommendation and Staff's Level 2 and 3 cost estimate disallowance recommendation, Ms. Rogers explained that only projects with a cost estimate level of "Actual," projects with a Level 3 cost estimate and "Projected Capital Overhead and Other Costs (Capital)" greater than 10%, and projects with a Level 2 cost estimate and "Projected Capital Overhead and Other Costs (Capital)" greater than 20% are included in Staff's recommendation for disallowance here; projects in which Staff has an alternate recommended disallowance are also not included.[1246]

In rebuttal, Ms. Uzenski opposed the disallowance, testifying that overhead costs are recurring, indirect costs that are routinely allocated to all capital projects executed by the Company, including IT projects.[1247] She stated that the Company created a list of overhead expenses and based on the total, an overhead rate was applied to capital project construction charges such as direct labor or materials.[1248] She further explained that contrary to Staff Witness Rogers' criticism, "[t]here is no receipt, contract, or other specific overhead cost item that can be traced back for each IT investment" and that "[t]here is no 'overhead purpose' for individual projects[.]"[1249]

Ms. Uzenski testified that the USoA requires DTE to include the capitalization of overhead costs and cited "Electric Plant Instruction item 4" to support its practice.[1250] And

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[1244] 5 Tr 5061.
[1245] 5 Tr 5061-5062.
[1246] 5 Tr 5060.
[1247] 4 Tr 2499.
[1248] 4 Tr 2500; See Exhibit S-12.10.
[1249] 4 Tr 2501.
[1250] 4 Tr 2500.

she reported that the Commission has consistently approved the inclusion of overhead costs in all capital projects, including IT projects.[1251]

In its brief, DTE relies on Ms. Uzenski's rebuttal testimony. Staff's brief reiterates its recommendation for a disallowance based on Ms. Rogers' testimony. Staff further argues that by its calculations, the amount of overhead costs have no pattern or method.[1252] To support this position, Staff notes that some IT projects do not have overhead costs even when capital costs are projected and the percentage of projected overhead costs is not consistently applied when it is included in a project.[1253] Staff argues that while overhead costs are appropriate for capitalization, the Company arbitrarily applies the "Projected Capital Overhead and Other Costs (Capital)".[1254]

In its reply brief, DTE maintains its opposition to the disallowance for the reasons previously argued and also contends that allocating the overhead costs more for some projects than others is consistent with the longstanding approach for these costs under the USoA.[1255]

This PFD finds that DTE has failed to justify the reasonableness and prudence of these costs, and Staff's recommended disallowance should be adopted. Not only has DTE not provided its method for applying these costs to future projects, it does not provide sufficient detail on how it calculated the requested costs for existing projects. And there is no evidence in the record to support DTE's claim that the Commission previously approved overhead costs such as those requested here.

[1251] 4 Tr 2501.
[1252] Staff brief, 82.
[1253] Staff brief, 82-84.
[1254] Staff brief, 82-83.
[1255] DTE reply, 82.

Consistent with the above discussion, this PFD adopts Staff's proposed disallowances of $0.731 million in 2023, $0.284 million in 2024, $2.297 million in 2025, and $11.542 million in the test year.

J. Corporate Staff Group

According to DTE, the Corporate Staff Group "provides a variety of Administrative and General type services to the Company and its affiliates. Capital investment is necessary for the CSG to deliver services to DTE affiliates. The major categories of capital investment for CSG relate to information technology, physical infrastructure, and fleet."[1256] DTE further explains that, like IT, many of the facilities and fleet costs are shared between the electric utility and other DTE affiliates, such as DTE Gas, "DTE Electric records 100% of the capital expenditures for CSG organizations and then charges a capital usage fee (Shared Asset Charge) to DTE affiliates for each affiliate's proportionate use of these assets." Ms. Uzenski testified concerning the Company's proposed $321.2 million in capital expenditures for 2024 through the test year for fleet, facilities, and other projects, as shown in Exhibit A-12, Schedule B5.8.[1257] Disputes concerning these costs are addressed below.

1. Fleet Capital Expenditures

Mr. Coppola initially recommended a reduction of $22.6 million in capital expenditures for fleet. In her initial brief, the Attorney General withdrew her recommendation, stating:

> Based on additional discovery received subsequent to the Company's filing of rebuttal testimony, the AG has determined that the Company now has

[1256] DTE brief, 120.
[1257] 4 Tr 2449.

supported its forecasted capital expenditures for fleet transportation and withdraws Mr. Coppola's proposed disallowance of $22,566,000 for 2026.[1258]

Staff witness Hansen recommended a test year adjustment of $1.362 million for EV fleet and maintenance, testifying that this amount represents unsupported emergent spending for repairs and parts replacements.

DTE did not address this adjustment in rebuttal or in briefing. Therefore, this PFD finds that Staff's recommended test year disallowance of $1.362 million should be adopted.

2. Facilities

a. Courtyard Project

In its application, DTE proposed $2.3 million in capital expenditures for the installation of furniture and structures for the courtyard at DTE's headquarters building.

In his testimony, Mr. Coppola recommended the Commission disallow the $2.3 million proposed for the headquarters courtyard project.[1259] Likewise, Staff witness Simmons recommended disallowance for the headquarters courtyard project.[1260]

In its brief, DTE states that it "accepts the $2.3 million decrease in capital expenditures related to the courtyard project."[1261] Therefore, per the Company's concession, $2.3 million for the headquarters courtyard project should be removed from the Company's capital expenditures.

b. Walker Cisler Building Façade

[1258] Attorney General brief, 69-70.
[1259] 4 Tr 3473.
[1260] 5 Tr 5186.
[1261] DTE brief, page 121.

DTE also requested capital expenditures for repairs to the Walker Crisler Building façade in the amounts of $1.0 million for 2025 and $2,254,000 for 2026. Mr. Coppola testified that an inspection by the City of Detroit showed areas of the façade that needed to be repaired, and that such repairs should not be capitalized but expensed the year in which they occur. Mr. Coppola recommended that the Commission disallow the capital expenditures of $1.0 million for 2025 and $2,254,000 for 2026, and increase DTE's O&M expense for the projected test year by $2,254,000.[1262]

In its brief, DTE states, "The Company accepts the decrease in capital expenditures and the increase to O&M expense."[1263] Therefore, the proposed capital expenditures for repairs to the WCB façade in the amounts of $1.0 million for 2025 and $2,254,000 for 2026 should be removed and the Company's O&M expense for the projected test year should be increased by $2,254,000.

c. Trombly Service Center

For the Trombly Service Center renovation project, DTE is requesting $5,254,000 in capital expenditures for 2026.[1264] Mr. Coppola testified that in response to discovery, DTE stated that the facility is slated for use in 2028 and 2029 and that the project will be competitively bid when the design is complete.[1265] Mr. Coppola testified that it appears the project is still in the initial phase of development with no design yet completed. As such, he asserts it is premature to include the capital expenditures for this project in the

[1262] 4 Tr 3471-3472.
[1263] DTE brief, page 121.
[1264] 4 Tr 3473; Exhibit A-12, Schedule B5.8.
[1265] 4 Tr 3473-3474.

instant rate case, and recommends the Commission remove $5,254,000 from the forecasted 2026 capital expenditures.

In her brief, the Attorney General argues that because no rebuttal testimony was offered pertaining to Mr. Coppola's recommended disallowance, Mr. Coppola's assertions remain unrebutted and that the Commission should adopt his recommendation and remove $5,254,000 from the 2026 forecasted capital expenditures. In its reply brief, DTE states that it "does not oppose this outcome at the present time."[1266]

This PFD agrees with the Attorney General that this project is still in the initial phases of development and therefore premature to include in the proposed capital expenditures. Additionally, DTE states that it does not oppose the removal of these expenditures. Therefore, this PFD recommends the Commission remove $5,254,000 from the 2026 forecasted capital expenditures for the Trombly Service Center renovation project.

d. Headquarters Plaza

DTE has requested capital expenditures in the amount of $4,001,000 for 2025 and $3,754,000 for 2026 ($7.8 million total) for renovations to optimize the open space for the plaza at the headquarters building. Mr. Coppola testified that based on discovery responses, it is unclear "what optimization is being done to the open space, why it is necessary, and why it should cost customers $7.8 million."[1267] Mr. Coppola noted that DTE's discovery response pertaining to this project points to plumbing repairs, which he asserts "does not match with the concept of space optimization."[1268] Therefore, Mr.

[1266] DTE reply brief, page 105.
[1267] 4 Tr 3472.
[1268] Id.

Coppola recommended the Commission remove the capital expenses of $4,001,000 for 2025 and $3,754,000 for 2026 associated with this project.

In rebuttal, Ms. Uzenski disagreed with Mr. Coppola's proposed disallowance regarding the plaza renovation project. Ms. Uzenski testified that DTE has initiated design work for the project and plans to solicit bids in the fourth quarter of 2025. She further testified that all of the pipes and plumbing in the plaza are original from the building's construction in 1972. Further, the first and second floors of the building need to be renovated as the outdated infrastructure does not meet city and state building codes. As such, DTE considers the project to be necessary and prudent and requests the Commission approve the requested $7.8 million for the project.[1269]

In briefing, the Attorney General relies on the testimony of Mr. Coppola and reiterates his call for the Commission to remove the $4,001,000 for 2025 and the $3,754,000 for 2026 from the Company's forecasted capital expenditures. The Attorney General notes that DTE has not yet solicited bids for this project and argues "DTE has not provided enough detail to support spending this much money on a renovation project that only benefits the Company, and not its ratepayers."[1270]

In its reply, DTE relies on Ms. Uzenski's rebuttal testimony and argues that it has already completed design work for this project and intends to solicit bids in the fourth quarter of 2025. DTE argues this project is necessary to comply with state and local building codes and is therefore reasonable and prudent.[1271]

[1269] 4 Tr 2498-2499.
[1270] Attorney General brief, page 70.
[1271] DTE reply brief, page 105.

This PFD agrees with the position articulated by the Attorney General that DTE has not presented enough evidence to support the proposed capital expenditures at this time, and recommends the Commission remove the $4,001,000 for 2025 and the $3,754,000 for 2026 from the Company's forecasted capital expenditures. Reasonable and prudent capital expenditures for the proposed project may be recovered in a future rate case, provided more evidence is presented in support of the proposal.

3. Other Corporate Projects and Adjustments

DTE included capital expenditures in the amount of $4,388,000 for 2025 and $4,567,000 for 2026 for other corporate projects.[1272] Mr. Coppola testified that through discovery, the Attorney General requested that DTE identify the projects included in those amounts. He testified that in response, "the Company stated that the amounts represent emergent work that may arise during the year and no specific projects have yet been identified."[1273] Mr. Coppola stated that the Commission has consistently rejected the use of placeholder amounts in forecasted capital expenditures and as such recommends that the Commission remove the forecasted capital expenditures in the amount of $4,388,000 for 2025 and $4,567,000 for 2026.

In her brief, the Attorney General argues that as no rebuttal testimony was offered pertaining to Mr. Coppola's recommended disallowance, Mr. Coppola's assertions remain unrebutted and that the Commission should adopt his recommendation and remove the forecasted capital expenditures in the amount of $4,388,000 for 2025 and $4,567,000 for 2026.

[1272] Exhibit A-12, Schedule B5.8, page 2, line 54.
[1273] 4 Tr 3474; Exhibit AG-17.

In its reply brief, DTE argues that it explained in discovery that these line items are related to emergent work and the requested expenditures are reasonable and prudent to address emergent situations.[1274]

This PFD finds the Attorney General's arguments to be persuasive. Because no specific projects have been identified for the use of the proposed funds, it would be inappropriate to grant DTE's request for such. Accordingly, this PFD recommends the Commission remove the forecasted capital expenditures in the amount of $4,388,000 for 2025 and $4,567,000 for 2026.

In addition to the above, Mr. Hanson recommended adjustments to "Other Miscellaneous" shown in Exhibit A-12, Schedule B5.8, p. 1, line 5. Including capital expenditure disallowances of $700,000 in 2025 and $800,000 in the test year for what Mr. Hanson deemed "placeholder amounts" or duplicative of costs included elsewhere.[1275]

DTE did not provide rebuttal or address this adjustment in briefing. Therefore, this PFD finds that these expenditures, $700,000 in 2025 and $800,000 in 2026 should be disallowed.

K. Transportation Electrification Plan

Mr. Foley outlined DTE's transportation electrification plan (TEP) in support of EV adoption in DTE's service area, and he outlined the Company's underlying TEP goals.[1276] He noted that in the U-21534 order, the Commission approved DTE's TEP, but with several modifications: (1) that the Company reallocate any unused funding from its

[1274] DTE reply, 105-106; Exhibit AG-17, page 8.
[1275] 5 Tr 5176.
[1276] 4 Tr 2613; 2615-2617, citing Exhibit A-29, Schedule S1; 2619-2625.

business charger rebate program to non-DAC (disadvantaged community)/rural on-route charger rebates; (2) that DTE offer rebates for "workplaces and shopping areas," which DTE has interpreted as offering rebates for all public L2 chargers; (3) that the Company allow self-attestation of customer interest for parties requesting multi-unit dwellings (MUDs) charger rebates; and (4) that the Company evaluate whether there would be benefits to offering charger output capacity tier-based school bus charger rebates to schools not using bi-directional chargers.[1277]

Mr. Foley presented DTE's proposal in the instant case to continue TEP execution. He discussed charging hubs, and he added that the Company also wished "to confirm that it has authorization to issue rebates beyond the forward test year in this case and that it can reallocate funding between rebate programs."[1278] Additionally, he touched on the Smart Charge pilot presented by Mr. Leuker as part of the DR portfolio, and the contribution in aid of construction (CIAC) waiver presented by Mr. Willis.[1279] Mr. Foley listed DTE's interpretation of EV-related guidance previously provided by the Commission, outlining a one-time CIAC waiver, an anticipated workgroup in relation to Level 1 and Level 2 (L2) commercial EV charging CIAC waivers, and the prior extension of the DCFC demand charge holiday. And he made note of the TEP BCA, and TEP annual status reports.[1280]

Mr. Foley also set forth the major elements of DTE's EV programming including : (1) residential customer rebates targeting low income (LI) and single family homes

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[1277] 4 Tr 2619-2620.
[1278] 4 Tr 2620.
[1279] 4 Tr 2621.
[1280] 4 Tr 2621-2622.

(SFHs); (2) business charger rebates targeting MUDs, public L2 chargers, and direct current fast chargers (DCFCs); (3) fleet charger rebates targeting fleet DCFCs and L2 fleet chargers; (4) education and outreach (E&O); the emerging technology fund; (5) TEP IT capabilities; (6) program administration; and recovery of investment related to the previously approved charging hubs pilot.[1281] He clarified that the rebate programs and emerging technology fund costs are deferred as a regulatory asset; the charging hubs pilot and the TEP IT capabilities are capital expenditures; and the E&O and program administration costs are O&M expenses.[1282]

Mr. Foley's recitation of CIAC and UMR investment, the parties' competing views and EV adoption forecasts, as well as charging hubs and the demand charge holiday, are addressed elsewhere in this PFD. Similarly, the structure and allocation of TEP expenditures are discussed in relation to cost of service. This leaves unanswered a recommendation in Staff's brief that DTE include analysis in its next TEP on how the One Big Beautiful Bill Act will impact EV adoption and load in the Company's footprint going forward.[1283] The Company agrees to this in its reply brief.[1284] This recommendation is reasonable, and this PFD recommends that this direction be included in the Commission's order.

Otherwise, the remaining issues and points regarding TEP and related matters are discussed below. Matters not discussed below, and not discussed elsewhere in this PFD, are otherwise recommended for approval without contest.

[1281] 4 Tr 2625-2626, citing Exhibit A-29, Schedule S1.
[1282] 4 Tr 2626.
[1283] Staff brief, 119.
[1284] DTE reply, 197.

1. TEP Information Technology Capabilities

Mr. Foley testified that DTE is proposing recovery of $0.3 million of capital investment in 2026 for TEP Capabilities, in addition to $1.6 million for 2025. According to him, in 2025, DTE is building data capabilities and dashboards for TEP metric tracking, including supporting the required TEP annual report data. DTE has issued an RFP seeking vendors for dashboard buildout; the 2026 spending is to refine or enhance dashboard capabilities.[1285] Mr. Freeman testified that Staff supports these investments, noting that "DTE may need additional IT spend to comply with the updated TEP filing requirements."[1286] Because this issue is uncontested, this PFD recommends its approval.

2. Transportation Electrification Plan O&M

Ms. Uzenski noted that the Commission approved DTE's original Charging Forward program in Case No. U-20162 to develop EV infrastructure with the costs deferred to a regulatory asset, with additional components of the program, and the name change to TEP, occurring in subsequent cases.[1287] She presented the amortization expense for the program.[1288] She stated that the regulatory asset is projected to have a balance of $68.7 million through December 2026 representing the deferred expense, less cumulative amortization.[1289] According to Mr. Foley, a $4.6 million increase is part of the amortization of the charging forward regulatory assets included in the $32.1 million

[1285] 4 Tr 2642.
[1286] 5 Tr 5208.
[1287] 4 Tr 2429.
[1288] 4 Tr 2429.
[1289] 4 Tr 2471.

electric regulated marketing O&M expense projected for 2026, as is a $4.1 million increase in DR programs presented by Mr. Leuker.[1290]

Mr. Foley also testified that DTE is proposing $1.5 million of O&M spending in 2026 for education and outreach (E&O) activities and $1.8 million for 2026 for program administration.[1291] Including the Smart Charge pilot to manage EV charging, Mr. Leuker testified that DTE is projecting $2 million in O&M spending for "various DR pilots, programs, and projects."[1292]

Mr. Coppola noted that DTE included $4,066,000 of DR costs and $1,340,000 for the Charging Forward program expansion in its test year projections while. DTE's discovery responses indicated that the demand response programs increased by $2.3 million between 2023 and 2024, and that the Charging Forward program spending increased by $1.0 million over the same year. [1293] As a result, Mr. Coppola opined that any increases in future year expenses were speculative, and he recommended the disallowance of the "$4,006,000 and $1,340,000 from the 2026 forecasted O&M expense."[1294]

In rebuttal, Mr. Foley found Mr. Coppola's characterization of the $1.34 million increase in EV programming as "speculative" to be "demonstrably false," characterizing the increase as a valid projection.[1295] Mr. Foley indicated that the increases were $0.124

[1290] 4 Tr 265-2654.
[1291] 4 Tr 2643-2646.
[1292] 3 Tr 1357-1359.
[1293] 4 Tr 3540.
[1294] 4 Tr 3540. Ms. McMillan-Sepkoski also recommended that $224,000 be disallowed for all regulated marketing O&M costs based on inflation rates used. 5 Tr 4987-4988. Mr. Foley rejected this suggestion. 4 Tr 2681.
[1295] 4 Tr 2678-2679.

million to $1.5 million total for E&O O&M, and an increase of $1.216 million for program administration to $1.805 million in 2026.[1296] The 2024 spending for these categories was split between O&M, regulatory asset, and capital treatment, not just O&M, so total E&O and program administration spending in 2024 was $2.8 million, so the spending increase that now appears solely in O&M is $0.505 million over 2024 levels, not $1.34 million as Mr. Coppola contends.[1297] Mr. Foley was also of the view that achieving the staffing levels contemplated in Case No. U-21297's adoption of the Charging Forward program justified the requested spending increase.[1298]

The Attorney General contests the characterization of Mr. Coppola's testimony as "demonstrably false," given that all forecasts and projections are, by their nature, speculative.[1299] She also indicates that the breakdown of cost projections for 2026 does not address the concern that an increase is not supported by the 2024 reduced spending amounts, or that the projected spending, based on the reduced spending in 2023 and 2024, is unlikely to occur and therefore is not reasonable and prudent. If the spending has not actually happened in the past, "the expenses are not as critically necessary as claimed."[1300] The Attorney General discounts Mr. Leuker's explanation of spending, and contends that, with the end of the $7,500 federal tax credit in September 2025, the TEP program will be even less active and "expenses should be throttled back" because the projected costs are not likely to be incurred by the Company. As a result, the Attorney

[1296] 4 Tr 2679-2680.
[1297] 4 Tr 2680.
[1298] 4 Tr 2680-2681.
[1299] Attorney General brief, 113-114.
[1300] Attorney General brief, 114-115.

General maintains her recommended disallowance.[1301] These points, but particularly the expected reduction in EV purchases after the September 2025 expiration of rebates, are raised in the Attorney General's reply brief.[1302]

DTE relies on the testimony that the total spending is now reflected in O&M, but was previously spread through other categories of spending, so the increase in total 2024 spending:

> The $1.340 million referenced by AG witness Coppola represents a projected increase in EV programming O&M spending from $1.965 million in 2024 to $3.305 million in 2026. This includes an increase in Education & Outreach (E&O) of $1.376 million to $1.500 million and an increase in Program Administration of $0.589 million to $1.805 million. To be clear, 2024 E&O and Program Administration spending was distributed across O&M, Regulatory Asset, and capital treatment. When aggregated, total 2024 spending was $2.800 million, meaning the actual increase in O&M is $0.505 million, not $1.340 million. Therefore, contrary to the assertions of AG witness Coppola, the Company's proposal is not "speculative."[1303]

The Company also applies its own inflation rate to counter Ms. McMillan-Sepkoski's downward adjustment of $244,000 of the 2026 overall forecasted TEP O&M.[1304]

Inflation is dealt with elsewhere in this PFD. Turning to the contested TEP E&O O&M spending, the amounts requested are not facially unreasonable, and the recommended disallowance should be rejected.

3. Miscellaneous Program Design Issues

Mr. Foley testified that DTE is proposing $1.5 million in 2025 and 2026 for E&O, maintaining the level of spending previously approved by the Commission and making the E&O pilot permanent to meet long-term needs. These customer outreach activities

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[1301] Attorney General brief, 114-115.
[1302] Attorney General, 67-68.
[1303] DTE brief, 215.
[1304] DTE brief, 215-216.

include EV Ride and Drives, emails, bill messages, print collateral, social posts, digital marketing, and the virtual showroom and website updates.[1305] It will now also cover eFleet Advisory Services, and Mr. Foley added that DTE is exploring a similar service for MUDs to ease the charger installation process.[1306]

For program administration, DTE is proposing $1.8 million in O&M expense in 2026 for establishment of a 14-member permanent EV team to develop and administer DTE's EV programming, specifically strategy, program execution, and facilitating EV-related federal funding opportunities for Southeast Michigan.[1307] Program administration costs will also support EV industry knowledge sharing, such as attendance at relevant working groups and conferences, and "paying for membership and software maintenance fees for program management tools."[1308]

Ms. Schuster outlined DTE's existing E&O programs, noting that DTE is considering extending its advisory services to enable EV charging deployment to MUD customers.[1309] She considered DTE's E&O, including DTE's website development, advisory services, marketing materials, engagement with community partners, and email and eBill communication to be critical to EV adoption.[1310]

Ms. Schuster indicated that range anxiety and high upfront costs for EVs and charging equipment are primary concerns for potential EV buyers.[1311] For everyday driving, the five top-selling EV models in the U.S. have mileage that exceeds the 30 to 50

[1305] 4 Tr 2643, citing Exhibit A-29, Schedule S1.
[1306] 4 Tr 2643.
[1307] 4 Tr 2643-2644.
[1308] 4 Tr 2644.
[1309] 5 Tr 3955-3956.
[1310] 5 Tr 3956-3958.
[1311] 5 Tr 3958-3959.

average miles per day of a U.S. driver, but the lack of widespread charger availability in rural areas and on routes to popular tourist destinations still requires advance planning by EV drivers for longer trips, and still necessitates continued support for the deployment of public charging infrastructure.[1312] However, at least some range anxiety can be ameliorated by continuing to improve the visibility of new and existing charging infrastructure, but "enabling behavior change requires improved information sharing proactive engagement and patience."[1313]

Ms. Schuster similarly observed that business owners and fleet operators have many of the same concerns that individuals do, but they also experience the inability to place bulk orders of comparatively more expensive EVs. They are also stymied by distribution system upgrades to support EV fleet depots taking two to six years; this prevents full use of EVs, and, in the aggregate, these concerns cause "hesitation in transitioning to EVs."[1314]

Ms. Schuster also outlined some of the considerations of MUD property managers, including total installation costs ranging from $5,000 to $10,000.[1315] Utilities, as local grid capacity experts and managers of EV charging rebate programs, are "ideal conduits for information;" they can educate customers about how EVs can meet their needs, the infrastructure needed to support the right EV, what incentives might be available, and how to take advantage of TOU rates or managed charging programs. They can provide

[1312] 5 Tr 3959-3960.
[1313] 5 Tr 3960-3961.
[1314] 5 Tr 3961-3963.
[1315] 5 Tr 3965-3967.

information to individuals, auto dealerships, governmental units, and community associations to disseminate accurate information.[1316]

Based on her testimony, Ms. Schuster had several recommendations. She recommended that the Commission needed to establish reasonable energization timelines, but utilities could improve outreach efforts to fleet customers, exploring the business needs of current and prospective EV fleet customers.[1317] In addition to benefiting customers, this could also benefit utility companies by permitting more accurate prediction of EV adoption and prioritization of infrastructure investments.[1318]

To do this, Ms. Schuster cited a 2020 Alliance for Transportation Electrification and Plug In America report that cited ride and drives, dealer partnerships, innovative partnerships, and leveraging data as best practices to improve engagement with EV programs to encourage EV adoption.[1319] For fleet customers, these best practices add outreach regarding incentive programs, leveraging relationships between fleet operators and utility account managers, hosting webinars with customers, hosting calls with installers and electricians, and clearly communicating energization timelines and costs.[1320] Utilities elsewhere have implemented these practices to positive effect.[1321] Ms. Schuster also noted that some utilities chose to partner with third-party entities to manage their outreach programs, and she provided examples of successful partnerships.[1322]

[1316] 5 Tr 3969.
[1317] 5 Tr 3964.
[1318] 5 Tr 3964-3965.
[1319] 5 Tr 3969-3972.
[1320] 5 Tr 3972-3973.
[1321] 5 Tr 3973-3975.
[1322] 5 Tr 3975-3979.

Ms. Schuster opined that DTE had only partially adopted these best practices. She recommended that DTE expand its advisory services to include MUD customers in similar fashion to its eFleet Advisory services. DTE could also adopt tools to more readily identify prospective LI and non-LI MUD customers by evaluating grid capacity, the age of existing buildings, and whether those buildings are EV-capable or EV-ready, targeting a wider variety of MUD properties. DTE should also reconnect with MUD rebate program participants to address questions and challenges, and should include this feedback, and what is learned from programmatic changes in its TEP to allow for interested party feedback.[1323]

Additionally, Ms. Schuster recommended that eFleet advisory services managers should be able to provide advice and use grid capacity data to identify potential EV customers, developing a coordinated outreach strategy based on information from existing account managers to reach customers. Ms. Schuster again recommended quarterly outreach to business rebate program participants, and combining this feedback with information from programmatic changes in DTE's TEP for interested party feedback.[1324] And Ms. Schuster recommended that DTE consider contracting with third-party providers to work with DTE's existing EV team to ensure effective implementation.[1325]

In relation to its existing programs, Ms. Schuster noted that DTE lists several electric vehicle service providers (EVSPs) on their web pages in relation to multiple rebate programs. She suggested that DTE host onboarding and follow-up educational events or

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[1323] 5 Tr 3979-3980.
[1324] 5 Tr 3980-3981.
[1325] 5 Tr 3981.

webinars to ensure that these EVSPs have the most recent information available, and to obtain participant feedback. She again recommended that the feedback be collected to improve the existing program, and be incorporated into the TEP to permit feedback from interested parties.[1326] In relation to new programs, Ms. Schuster suggested that DTE "could host regular EV-focused webinars with targeted information for a variety of customers" and other interested governmental and private parties.[1327]

Ms. Schuster also suggested development of a dealership network. She recommended the same onboarding and continuing education process as she recommended for EVSPs. This could result in improved rebate plan participation, as well as increase enrollment in TOU rates and the Smart Charge pilot.[1328] Assessment indicators could include the number of participating dealers, the number of dealers converted to participate in the program, the number of trained sales personnel, the number of customers inquiring about EVs, and the number of customers who engaged with a trained salesperson who participated in a charging rebate program or TOU rate. Ms. Schuster again recommended that participant feedback could be used to improve the existing program, but it should also be included in the TEP to allow for the feedback of interested parties.[1329] She further suggested that automotive manufacturers and organizations like the Detroit Auto Dealers Association could partner with DTE to develop and manage these "relationships."[1330]

[1326] 5 Tr 3981-3982.
[1327] 5 Tr 3984.
[1328] 5 Tr 3982-3983.
[1329] 5 Tr 3983.
[1330] 5 Tr 3984.

Ms. Schuster recommended use of key metrics to evaluate new, existing, and developing programs, with these metrics including participation rates, conversion rates, and satisfaction rates.[1331] She also recommended that "given the complex nature of E&O, management of transportation electrification programs, and the challenges inherent to facilitating consumer behavioral changes, the Company could benefit from working with a third-party entity to manage its TEP programs," asserting that these entities have relevant expertise, can alleviate management burden, and improve program efficiencies while encouraging innovation.[1332] In relation to DTE's 2026 TEP, Ms. Schuster also recommended that DTE report findings from a viability assessment to working with the recommended third-party contractor, expand its E&O budget to increase proactive efforts, and propose evaluation metrics and their underlying formulae.[1333]

Mr. Foley replied that DTE's current TEP was launched in mid-February 2025 following its approval in January by the Commission, so there was insufficient time to fully assess the effectiveness of current programming prior to the Company's filing of the instant case. DTE continues to refine its E&O and advisory services as it learns more.[1334] He disagreed with the suggestion that DTE should consider the use of a third-party contractor to manage at least a portion of its TEP and customer engagement efforts. He also disagreed that assessment of the use of a third-party contractor, and other findings, should be included in DTE's 2026 TEP, particularly where the existing TEP programming was still being assessed. He recommended rejection of this recommendation.[1335]

[1331] 5 Tr 3984-3985.
[1332] 5 Tr 3985-3986.
[1333] 5 Tr 3986-3987.
[1334] 4 Tr 2665.
[1335] 4 Tr 2665, 2667.

Mr. Foley also thought the recommendation could run counter to Commission orders approving establishment of an internal team dedicated to development and administration of TEP programming, and that resources were better attributed to improving current programming, which DTE continues to refine.[1336] However, Mr. Foley found merit in Ms. Schuster's recommendations to improve E&O offerings and establish metrics to measure their success. He suggested that consideration of these issues should be submitted in greater detail and considered by participants in the collaborative process leading to DTE's 2026 TEP submission.[1337] Mr. Foley generally requested rejection of Ms. Schuster's recommendations in this proceeding stating that, if the Commission was inclined to do so, it could direct DTE to consider the recommendations as part of the 2026 TEP formulation processes.[1338]

MEIU's brief largely relies on Ms. Schuster's testimony, highlighting the importance of E&O, and the potential of EVs to apply downward rate pressure.[1339] MEIU strongly "urge the Commission to seriously consider" directing DTE to consider third-party management of its TEP programming.[1340] MEIU also recommend that the Commission adopt Mr. Foley's rebuttal suggestion, that, if the Commission is going to direct DTE to consider Ms. Schuster's recommendations, it actively direct DTE to consider her recommendations as part of the TEP development process.[1341]

[1336] 4 Tr 2665-2666.
[1337] 4 Tr 2666-2667.
[1338] 4 Tr 2666-2667.
[1339] MEIU brief, 5-15.
[1340] MEIU brief, 15.
[1341] MEIU brief, 15.

In its brief, the Company stresses that the TEP was relatively new in its implementation at the time testimony was filed in the case, so there had not been time assess "effectiveness or justify a shift to third-party administration."[1342] It reiterates Mr. Foley's contention that conducting assessments regarding third-party administration would contravene Commission orders establishing a DTE internal team to develop and administer TEP programming. Otherwise, DTE repeats its position that some of Ms. Schuster's E&O recommendations have merit and should be submitted in the 2026 TEP development process in U-21492.[1343]

This PFD rejects MEIU's recommendations for this proceeding. However, the Commission notes that all parties should actively participate in the processes to generate DTE's 2026 TEP. This PFD also cautions parties that extensive litigation regarding programmatic issues regarding DTE's TEP, as opposed to investments in or expenses for that program, should not be included in a rate case, where limited resources are available and time limits are strict. DTE regularly files TEPs in another proceeding, Case No. U-21492, and recommended modifications to the TEP can be addressed there.

4. Rebate Program Extension and Subprogram Funding Reallocation

Mr. Foley presented the Company's request for authorization to treat up to $128.3 million as a regulatory asset between 2025 and 2028 in support of its TEP rebate programs, which he contended align with the Company's most recent TEP and a January 2025 Commission order.[1344] The TEP rebate program subsegments are set forth in Table

[1342] DTE brief, 207-208.
[1343] DTE brief, 207-208.
[1344] 4 Tr 2619, 2627-2630.

1 of Mr. Foley's testimony.[1345] DTE also sought "to confirm" that it could record rebates as a regulatory asset beyond 2026, but not beyond the 2028 end of the current TEP.[1346] The regulatory asset has otherwise largely been discussed elsewhere in this PFD. Mr. Foley outlined DTE's TEP fleet, residential and business charger rebates, including low income (LI) and multi-unit dwellings (MUDs), and he outlined their eligibility requirements, as well as rebate issuance and targets.[1347]

Mr. Foley further explained that the Commission previously directed DTE to reallocate unused legacy business charger rebate funding to non-DAC/non-rural on-route DCFC rebates, approximately $3.53 million, but that the Commission also directed DTE to offer public L2 charger rebates without authorizing incremental funding for the program.[1348] As a result, DTE reallocated $4.39 million from non-DAC/non-rural on-route DCFC rebates to public L2 charger rebates.[1349]

DTE sought "to confirm" that the Company could "reallocate funding between rebate programs as needed," which Mr. Foley characterized as confirmation that "the Commission is authorizing a total level of Regulatory Asset treatment, and not specific rebate program levels."[1350] The Company sought "to confirm that it can continue to reallocate funding between programs as needed to accommodate prevailing adoption trends."[1351] Mr. Foley indicated that the fund shifting was necessary because the Company would need to stop issuing rebates for specific segments of the TEP rebate

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[1345] 4 Tr 2627.
[1346] 4 Tr 2619, 2627-2630.
[1347] 4 Tr 2631-2638. 4 Tr 2634, Table 4.
[1348] 4 Tr 2634-2635.
[1349] 4 Tr 2634.
[1350] 4 Tr 2628-2629, 2635.
[1351] 4 Tr 2634-2635.

programs once projected maximum funding levels were depleted for that segment, even if rebate funds under the overall approved spending umbrella still existed. Mr. Foley further characterized this as maintaining the flexibility necessary to fund rebates, particularly the Public L2 Charger rebates directed by the Commission in Case No. U-21534.[1352] Mr. Foley went on to state that DTE does not keep, and customers do not pay for, any unused rebate funding, briefly explaining the rebate and regulatory asset process, and referencing Ms. Uzenski's testimony and Exhibit A-13, Schedule C5.9.1, in relation to the Charging Forward Regulatory Asset costs.[1353]

Although Ms. McMillan-Sepkowski indicated Staff's support for the TEP rebate program in general, Staff opposed unrestricted reallocation of funds between programs, with Mr. Krause citing testimony first presented in Case No. U-20836 to bolster this opposition. [1354] According to Mr. Krause, because the TEP is designed to reasonably guarantee benefits for customers, particularly encouraging off-peak charging, shifting funding undermines the benefits and program goals.[1355] Staff considered maximum net customer benefits to be more important than DTE's "respon[se] to the prevailing adoption trends in [DTE's] service territory."[1356]

Mr. Freeman also testified that Staff, supports regulatory asset treatment for rebates through 2028, as requested by DTE, but reiterated Staff's opposition to DTE unilaterally reallocating funding between different EV programs because it does not allow

[1352] 4 Tr 2629-2630.
[1353] 4 Tr 2630.
[1354] 5 Tr 4987.
[1355] 5 Tr 5247-5248.
[1356] 5 Tr 5247-5248.

for proper oversight.[1357] He suggested that the Company set a maximum program budget and apply what it learns in its next rate case and program budgets, but not reallocate unspent funds. Staff otherwise supported DTE's proposed rebate targets.[1358]

Ms. Schuster summarized her understanding of DTE's proposal to reallocate TEP rebate funding, including the proposed reallocation of $4.39 million from the non-DAC/non-rural on-route DCFC program to the public L2 program, and DTE's request to shift funds from one subsegment of the rebate program to more popular ones, allowing the programs to exceed target adoption levels and "continue without interruption."[1359] She noted DTE's discovery response in Exhibit MEIU-1.11 indicating that the Company will use its forecasted rebate issuances with current funding to identify where program funding is likely to be exhausted versus where there programs are likely to have unused funds, but only once there is "sufficient data on rebate issuances by program" for analysis of multiple scenarios.[1360] Ms. Schuster agreed with shifting funds to create the required public L2 program, but expressed concern that any other shifting could result in negotiation of spending levels in a rate case only to have DTE unilaterally reallocate funds soon after.[1361]

Ms. Schuster indicated that DTE could be granted authority to reallocate funds subject to a formal, expedited, *ex parte* request to the Commission. Or, she posited, the Commission could generate a definition and process by which DTE could assess and

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[1357] 5 Tr 5206-5207.
[1358] 5 Tr 5207.
[1359] 5 Tr 3987-3989.
[1360] 5 Tr 3989.
[1361] 5 Tr 3989-3990.

implement reallocation.[1362] If the Commission "initiate[d] a process to define guardrails or circumstances under which the Company could reallocate funds," Ms. Schuster opined that the outreach efforts and adoption levels committed to each subsegment program should be considered in the reallocation process.[1363] Without such guardrails, Ms. Schuster recommended against allowing DTE to reallocate funds between TEP programs "without further review."[1364]

In his rebuttal, Mr. Foley stated that "the Company maintains that having the ability to reallocate funding between programs would allow the Company to provide maximum support of EV adoption in instances where one rebate program's funding is depleted but funding is available elsewhere."[1365] However, DTE acknowledged Staff's and Ms. Schuster's concerns regarding unilateral fund shifting between rebate programs, and found Ms. Schuster's suggestion of "guardrails" acceptable to balance concerns about unilateral action with allowing DTE "to respond quickly to prevailing market trends."[1366] As a result of this, Mr. Foley again requested approval to record TEP regulatory assets beyond 2026, and recommended that the Commission "[d]irect Staff to establish guidelines that would allow the Company to shift funding between programs based on prevailing market trends. The Staff should establish these guidelines in consultation with other interested" parties.[1367]

[1362] 5 Tr 3990.
[1363] 5 Tr 3990-3991.
[1364] 5 Tr 3991.
[1365] 4 Tr 2660-2661.
[1366] 4 Tr 2661.
[1367] 4 Tr 2662.

Ms. Schuster's rebuttal addressed Mr. Krause's suggestion that rebate subprograms supporting DCFC charging encourage on-peak use, while residential and Level 2 programs are more likely to encourage off-peak use. She also focused on Mr. Krause's testimony that reallocation is only beneficial if it leads to more off-peak charging.[1368] While Ms. Schuster agreed that DTE should not be permitted to reallocate funds between EV rebate programs without "guardrails or Commission approval," she reasserted that public charging alleviates range anxiety.[1369] This increases EV adoption, which will result in more EV charging, and, ultimately EV charging revenues will outweigh costs and provide downward rate pressure for all. She took the position that all rebate programs thus help realize ratepayer benefits.[1370] As a result, she recommended that Mr. Krause's testimony be largely disregarded, and otherwise recommended that the Commission define through a collaborative process guardrails or circumstances to permit DTE "to determine reallocation eligibility."[1371] Or DTE could seek expedited, *ex parte,* approval for fund reallocation.[1372] These points, and Ms. Schuster's recommendations, are repeated in MEIU's initial and reply briefs.[1373]

DTE's brief makes the same points as Mr. Foley's direct and rebuttal testimony, repeating the $128.3 million regulatory asset spending running beyond through 2028, and noting that suspending issuance of rebates until approval in future rate cases could hamper EV adoption, and be inefficient, unnecessarily costly, and confusing to

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[1368] 5 Tr 4008-4009.
[1369] 5 Tr 4009-4010.
[1370] 5 Tr 4010.
[1371] 5 Tr 4011.
[1372] 5 Tr 4011.
[1373] MEIU brief, 16-18. MEIU reply, 7-10.

customers.[1374] The brief attempts to recharacterize the proposed reallocation of funds between programs as "avoiding the maximum level being applied to each rebate program," asserting that reallocation "would allow the Company to provide maximum support of EV adoption."[1375] In Staff's near-universal rejection of reallocation, DTE fixes on Mr. Krause's statement that it could be allowed if it increased off-peak charging.[1376] Focusing on Ms. Schuster's concerns, however, DTE repeats its recommendation that it be permitted to reallocate funds, but that Staff, with interested party collaboration, should be directed by the Commission to establish guidelines for the shifting.[1377] DTE raises the same points in its reply brief.[1378]

Staff repeats in its brief that the TEP was designed for customer benefit, so that any deviation from the spending proposed in the TEP "should be only considered with appropriate caution."[1379] Staff rejects suggestions that funding should be shifted due to market pressures because market pressures, even with guardrails, are too vague in concept, particularly where any shifting should be for customer benefit.[1380] However, Staff supports DTE's request to record EV rebates as a regulatory asset beyond the test year, ensuring a lack of interruptions in current EV programs and their rebates, within the TEP timeframe of 2028.[1381] Staff also supports the Company's DCFC, Level 2, and business fleet charger rebate requests.[1382]

[1374] DTE brief, 210-213
[1375] DTE brief, 211-212.
[1376] DTE brief, 212, citing 5 Tr 5248.
[1377] DTE brief, 212-213.
[1378] DTE reply, 198.
[1379] Staff brief, 194-195.
[1380] Staff brief, 194-195.
[1381] Staff brief, 118.
[1382] Staff brief, 119.

In their brief, MNSC support the reallocation of $4.39 million from the non-DAC/non-rural on route DCFC program to the public L2 program appears in its brief, but they clarify that reallocation of funds without additional review should only occur after the Commission engages interested parties and establishes "a process with 'clearly defined and measurable guardrails' to govern future reallocations."[1383]

Because it is without opposition, this PFD recommends extending regulatory asset treatment until the 2028 end of the current TEP. And although Staff opposes allowing DTE to shift funds between rebate subprograms without oversight, because a proposal is being in the made in the instant case, where there is oversight, and no alternate funding to comply with the Commission's prior directive has been presented, this PFD recommends permitting the shifting of $4.39 million from the non-DAC/non-rural on-route DCFC program to the public L2 program between 2025 and 2028.[1384]

The issue of allowing DTE to unilaterally reallocate funds between rebate subprograms without Commission oversight is another matter entirely. Permitting DTE to shift funds subject to guidelines is not without precedent, and it is an idea that, conceptually, has merit. Nevertheless, neither DTE nor MEIU provide concrete examples of what guardrails might be imposed on the concept, leaving it to Staff to develop and provide guidance. If such guidance can be generated to be useful by the end of 2026, DTE may request permission to reallocate funds subject to guardrails it proposes in its next TEP or rate case filing.

[1383] MNSC brief, 181-182.
[1384] See fn 6, 4 Tr 2627, providing the breakdown of the funding shifts DTE proposes.

This PFD therefore recommends against permitting reallocation without a more comprehensive proposal from DTE for what standards would be employed regarding fund reallocation, and how the Company would report such fund reallocation to permit Commission oversight.

5. Contributions in Aid of Construction for Residential EV Infrastructure

Mr. Foley recognized the Commission's January 2025 directive that DTE propose a one-time CIAC waiver for new residential customer load including new installations of EV charging equipment subject to specific voltage requirements, and that Staff convene interested persons to determine the course of L1 and L2 commercial EV charging CIAC waivers.[1385] In compliance with the Commission's guidance, Mr. Willis proposed updates to the CIAC standard allowance table for customers with load greater than 1000 kW that he indicated was consistent with the method approved in Case No. U-21534.[1386] And he represented that DTE held a discussion with Staff and interested parties on March 19, 2025.[1387]

As a result, Mr. Willis proposed the addition of language to tariff Section C6.1(16) as reflected in Exhibit A-16, Schedule F8.[1388]

Mr. Woolley generally supported the CIAC waiver to avoid disproportionate costs falling on EV owners who trigger broader system upgrades, thereby creating capacity and benefits for multiple consumers.[1389] However, he expressed some concern regarding the wattage limitations of the waiver, particularly fearing that families with two EVs could

[1385] 4 Tr 2621.
[1386] 4 Tr 1750.
[1387] 4 Tr 1750.
[1388] 4 Tr 1750-1751.
[1389] 5 Tr 4793.

install a second charger and unwittingly exceed the waiver's limits. To address this, he recommended that DTE proactively reach out to EV owners to help them stay within the 9.6 kW and 10kW waiver thresholds. By assisting customers to stay within the waiver thresholds, Mr. Woolley opined that this would minimize the cost of EVs to their owners, to ratepayers dealing with increased electricity demand on the grid, and to DTE of system upgrade costs.[1390] He further opined that this could be based on metering data and that it would not require disclosure of personally identifiable information outside the Company.[1391]

In rebuttal, Mr. Foley testified that Mr. Woolley's "recommendations are unnecessary and could result in customer confusion and dissatisfaction."[1392] According to Mr. Foley, while the proposed change in tariff would permit DTE to charge more if customers exceed 9.6 kW demand at the meter, or exceed total connected load of 10 kW, DTE is not currently charging residential customers CIAC if they exceed load, and it does not intend to do so. The unnecessary education about a potential charge that DTE does not intend to levy is likely to confuse people and discourage EV adoption.[1393] However, Mr. Foley conceded that, if DTE changes its position in the future, outreach and education regarding CIAC for charging equipment in excess of 9.6 kW "may be appropriate."[1394] In its brief, DTE characterizes Mr. Woolley's recommendations as "simply unnecessary," because DTE is not charging residential customers CIAC for total connected load in

[1390] 5 Tr 4793-4795.
[1391] 5 Tr 4794-4795.
[1392] 4 Tr 2672-2673.
[1393] 4 Tr 2673-2674.
[1394] 4 Tr 2674.

excess of 10 kW, and it does not intend to do so.[1395] DTE's brief reiterates that the recommended outreach could result in customer confusion, dissatisfaction, and disinclination to adopt EVs.[1396]

MNSC responds in their brief that the Commission should direct DTE to specify in its next rate case if the CIAC waiver policy remains unchanged. If the policy has changed, and fees have been assessed to customers exceeding the 9.6 or 10 kW thresholds, DTE should indicate how many times this has happened.[1397]

In its reply brief, the Company agrees to provide the information.[1398] While this PFD agrees that DTE should not have to educate customers about something that is unlikely to happen, MNSC's response regarding a change in policy, and fees assessed if the policy changes, has merit. Unopposed, this PFD recommends that DTE be directed to report if it starts charging CIAC if a residential customer exceeds 9.6 kW of charging demand, or 10 kW of total connected load, and report how much and how often fees are being assessed.

6. Benefit Cost Analysis of Transportation Electrification Plan

Mr. Foley stated that the Commission has found DTE's TEP BCA reasonable in the past, and that the Company anticipates using the BCA tool being developed in Case No. U-20898 when it is available.[1399] In contrast, Mr. Woolley takes issue with the narrowness of what is considered a benefit of the TEP, and he takes issue with the five-year amortization used in the BCA. He contends that the 5-year amortization of the rebate

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[1395] DTE brief, 208-209.
[1396] DTE brief, 209.
[1397] MNSC brief, 188-189.
[1398] DTE reply, 197.
[1399] 4 Tr 2621-2622.

"counts only 10% of projected EV load (ignoring network effects), omits societal benefits, and consequently risks associating the TEP with Michigan's growing affordability concerns, potentially fueling political opposition to EVs."[1400] He recommended considering societal benefits, like avoided health costs from pollution and avoided gasoline costs, as monetary benefits. And he recommended extending the rebate amortization schedule to 10 years to better match the useful life of charging infrastructure investments while minimizing short-term rate pressure.[1401]

Mr. Woolley also recommended that DTE use the BCA collaborative tool in the rate case following when it becomes available.[1402] These sentiments were repeated in MNSC's brief, with some elaboration on the Company's $56 million in net ratepayer benefits reflected in its BCA, the societal benefits that should be included in the BCA going forward, and recognition that the Company does not oppose lengthening the amortization to 10 years.[1403] In rebuttal, Mr. Foley verified that DTE does not object to a 10-year amortization period for TEP regulatory assets,[1404] which was repeated in DTE's brief.[1405]

Mr. Freeman discussed the Benefit-Cost Analysis Tool Collaborative (Collaborative or BCA Collaborative) that is developing a BCA tool for distributed energy resources, including EVs. The goal is to have the tool completed in 2026.[1406] Staff supports Mr. Woolley's recommendation that the BCA tool be used if it is completed in

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[1400] 5 Tr 4796. The amortization period for TEP costs is discussed further under COSS and Rate Design.
[1401] 5 Tr 4796-4798, 4817.
[1402] 5 Tr 4796-4798, 4817.
[1403] MNSC brief, 179-184.
[1404] 4 Tr 2662-2663.
[1405] DTE brief, 212.
[1406] 5 Tr 5211.

time for the Company's 2026 TEP development.[1407] However, because Mr. Woolley does not provide a sample calculation for how societal benefits could be calculated, and how they could be used to reduce DTE's costs and customer bills, "there is no way for Staff to support or reject the proposal."[1408]

This PFD recommends that the existing BCA used by DTE be found to be acceptable, as it has been in the past. Staff's point, that no calculation has been provided for consideration to determine how societal benefits could be tallied as part of the BCA, is well taken. This PFD further recommends that DTE use the BCA collaborative tool in the rate case following when the tool becomes available, which DTE already anticipates doing. This PFD is not recommending its required usage in relation to the 2026 TEP because it seems unlikely that the tool will be available in time, although DTE should be encouraged to use it if it is.

7. Smart Charge Pilot

Mr. Leuker presented the history of the Smart Charge pilot, also known as EV DR, indicating that it was launched in 2019 to assess the effectiveness of the Open Vehicle Grid Integrated Platform (OVGIP), and it transitioned to incorporate managed charging in July 2023 with the TOU rate rollout in March 2023.[1409] The managed charging automatically initiates charging to occur during off-peak rates to provides the lowest cost to customers and lessen drain on the grid, as well as track if managed charging results in a change in the EV charging times already scheduled by customers.[1410] To do this, DTE

[1407] 5 Tr 5211.
[1408] 5 Tr 5212.
[1409] 3 Tr 1358.
[1410] 3 Tr 1358.

continued to work with Ford, GM, and BMW, and added the WeaveGrid platform, which also enrolls Tesla drivers to the pilot.[1411] While Staff and the Commission have been supportive of the Smart Charge pilot, DTE's Fall 2024 RFP to find a program implementer to add the Smart Charge pilot as a DR portfolio program resulted in DTE maintaining Smart Charge as a pilot. "The Company intends to keep the Smart Charge a pilot while additional value streams are analyzed."[1412]

Mr. Woolley explained that most EV owners plug in their cars when arriving home from work, which can draw between 5-9 kW from a Level 2 charger and nearly double a household's peak load during system peak hours.[1413] This would ultimately require circuit upgrades, transformer replacements, and other improvements, thereby increasing electricity rates and hindering EV adoption. Instead, the pilot incentivizes managed charging, charging vehicles at off-peak hours overnight while an EV sits idle.[1414] DTE enrolled 2,193 customers in the pilot between August 2023 and December 2024 through two managed charging service providers, with data from one showing very few customer overrides of the managed charging schedule shifting charging to off-peak hours.[1415]

Mr. Woolley calculated that the pilot added approximately $4,762 in incremental capacity costs in 2024 while generating over 3.7 GWh in mostly off-peak electricity sales, producing gross margin revenue of over $332,000, and an estimated $327,277 in net distribution revenue for DTE - $222,405 after customer incentive costs - while reducing

[1411] 3 Tr 1358-1359.
[1412] 3 Tr 1359.
[1413] 5 Tr 4799, 4802.
[1414] 5 Tr 4799.
[1415] 5 Tr 4780-4805.

all but one Smart Charge customers' bills.[1416] Without calculating the impact of unmanaged charging in relation to the benefit, Mr. Woolley calculated a Smart Charge benefit of approximately $47.82 per participating vehicle; for 32,000 EVs in DTE's service territory, Smart Charge could provide $1.5 million in annual net revenue, which he considered to be a conservative estimate.[1417]

From this, Mr. Woolley concluded that the pilot results in substantial grid benefits and significant electricity sales with minimal incremental capacity costs while requiring no change in participating customer behavior. Mr. Woolley recommended that DTE integrate Smart Charge into its DR portfolio as a permanent program with enrollment scaled to match the scale and projected growth of EV adoption, and he recommended aggressive scaling by DTE.[1418] To do otherwise, according to Mr. Woolley, would leave cost savings unrealized while exposing customers to avoidable grid costs.[1419]

In rebuttal, Mr. Leuker clarified that DTE has extended its contracts with WeaveGrid and Charge Scape through 2026 to analyze additional value streams, but he opposed conversion of the Smart Charge pilot to a permanent program.[1420] Mr. Woolley bases his opinion on plug-in times for Smart Charge enrollees, but, Mr. Leuker contends, this is not indicative of when a vehicle begins charging, adding that many EV owners plug in their vehicles when they come home from work but then use managed charging software to "deploy at the most optimal time," generally off peak. [1421] DTE's analysis of

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[1416] 5 Tr 4805-4808.
[1417] 5 Tr 4808.
[1418] 5 Tr 4808-4809, 4817.
[1419] 5 Tr 4808-4809.
[1420] 3 Tr 1387-1388.
[1421] 3 Tr 1387-1388.

energy consumption patterns of unmanaged EVs indicates that they charge during off-peak hours, like "their managed charging counterparts, and do not add substantial on-peak load," as shown in Figure 4 of Mr. Leuker's rebuttal testimony.[1422]

Mr. Leuker also took issue with Mr. Woolley's exclusion of the EV management fee paid per enrollee, and the platform fees that are part of the administrative costs for DERMS solutions; instead of showing net revenue of $47.82 per vehicle, these costs would yield a negative net incremental revenue per vehicle of $104.55.[1423] Because the value of the program is still unknown, the conversion of the pilot to a program that would then be aggressively scaled could result in scaling a program where the costs outweigh the benefits.[1424] As one of the "value streams" it intends to analyze, between now and the end of 2026 DTE intends to quantify how EV managed charging avoids or reduces the need for investment in grid infrastructure.[1425] DTE plans "to quantify how managed charging can affect the number and size of EV chargers that can be safely accommodated on residential transformers."[1426] Mr. Leuker added that, if the pilot were scaled into a program, it would require $4.4 million in annual administrative costs. He recommended continuing Smart Charge as a limited pilot through 2026 to allow for additional analysis, but, if the pilot is converted into a program, that the Commission approve $4.4 million in additional annual O&M costs to support the program.[1427]

[1422] 3 Tr 1388-1389.
[1423] 3 Tr 1389-1390, Table 1.
[1424] 3 Tr 1390-1391.
[1425] 3 Tr 1391.
[1426] 3 Tr 1391.
[1427] 3 Tr 1391-1392.

MNSC's brief largely raises the same points and recommendation to convert the pilot to a permanent program as Mr. Woolley's testimony, highlighting his conclusion that the pilot "is highly effective at controlling charging behavior and delivers substantial grid benefits – notably, increased electricity sales with minimal incremental capacity costs."[1428] MNSC contend that DTE's rebuttal is built on different data than that provided in discovery, and the Company does not reconcile the discrepancies in the information. Instead, the brief takes issue with DTE's undocumented assertion that EV drivers modify their charging in the same manner as managed charging participants, characterizing DTE's position as contrary to the record in other Commission proceedings that shows EV drivers without incentives or automation tend to charge their vehicles during peak hours as soon as they arrive at home.[1429] Although time of use rates "are a positive step," they are not generally a substitute for managed charging, and can still create localized spikes in demand, and does not allow for real-time charging adjustments, grid optimization, or other benefits of managed charging.[1430]

MNSC stress that scale of the program is key to efficiency and benefit growth. MNSC recommend conversion of the pilot into a permanent program with enrollment quickly being scaled to match current and projected EV adoption.[1431] In the alternative, the brief recommends that DTE be required "to provide detailed information on Smart Charge's performance, costs, and enrollment in its next TEP, including: updated benefit-

[1428] MNSC brief, 184-185.
[1429] MNSC Brief, 186.
[1430] MNSC brief, 186-187.
[1431] MNSC brief, 186-187.

cost analysis using consistent data sets; comparison of Smart Charge cost-benefit to unmanaged charging; and evaluation of administrative cost trends at scale."[1432]

DTE speaks only generally about its DR programs and TEP, and it does not appear to specifically address the Smart Charge pilot in its briefs.[1433]

This PFD finds that MNSC's recommendation to direct DTE to convert the pilot into a scaled DR program should be rejected at this time. As the Company points out, it is still analyzing value streams for the program based on its pilot. However, MNSC's request for information regarding Smart Charge in DTE's next TEP has merit. Insofar as the information requested has been gathered, and Mr. Leuker's rebuttal testimony indicates that it has, DTE should be required to provide information on Smart Charge's performance, costs, and enrollment. Additionally, this PFD takes to heart MNSC's assertions that DTE's rebuttal testimony relies on data not provided in discovery and that conflicts with the data that was provided. While MNSC should be mindful that it is not DTE's responsibility to read a requestor's mind when responding to discovery, DTE should also be mindful to comply with the spirit, as well as the letter, of discovery requests.

L. Accumulated Provision for Depreciation

The differences between DTE's, the Attorney General's and Staff's balance for the accumulated provision for depreciation results from differences in net plant projections, as discussed above. As shown in Attachment B to this PFD, the above recommendations result in an accumulated provision for depreciation of approximately $6,894,918.000 This balance should be adjusted consistent with the Commission's final order in this case.

[1432] MNSC brief, 187.
[1433] DTE brief, 92-93, 206-216. DTE reply, 74, 166, 196-199.

M. Working Capital

Mr. Vangilder presented a projected working capital amount of $1.375 billion as shown in Exhibit A-12, Schedule B1. Mr. Coppola proposed four adjustments, one of which, a $4.7 million adjustment to Interest Payable, was agreed to by the Company. The second adjustment, a reduction of $26.94 million related to the Monroe regulatory asset balance for the Monroe Fly Ash Basin was discussed and adopted above. Staff proposed a disallowance of $5.8 million in other accounts receivable related to non-utility balances, which DTE also accepted.[1434]

Mr. Coppola also recommended an increase of $9.5 million to DTE's Taxes Payable balance of $2.4 million. Mr. Coppola testified that when asked in discovery why Taxes Payable were expected to decrease from the $11.9 million 2023 year end balance, considering that the rate increase requested in this case would result in an increase in taxable income, the Company responded that "it forecasted a taxable loss for the 2026 test year," referencing the calculation in Exhibit A-13, Schedule C8.[1435]

Mr. Coppola opined that the Company's assumptions are unrealistic and its calculation of Taxes Payable is "seriously flawed."[1436] He noted that in DTE's most recent rate cases, the Company has received approximately 55% of the amounts requested. Mr. Coppola suggested that this 55% increase in revenues could be imputed, a more reasonable approach would be to use the 2023 year-end balance of $11.9 million, which would increase working capital by $9.5 million.[1437]

[1434] DTE brief, 24-25.
[1435] 4 Tr 3480.
[1436] Id.
[1437] Id.

In rebuttal, Company witness Wisniewski countered that "[t]he Company's calculation of Taxes Payable starts with the historic balance and makes changes that are driven by detailed calculations of current income tax expense that utilize test-period data and assumptions, which is consistent with generally accepted accounting principles (GAAP)."[1438] She cited Schedules C8, C9, and C10 of Exhibit A-13 that illustrate DTE's development of Taxes Payable.

In briefing, the Attorney General points to Exhibit AG-76 p. 3, wherein DTE admitted that it did not include any revenue from the instant rate case in its calculation of Taxes Payable, arguing that [t]his omission clearly understates the amount of Income Taxes Payable and directly and unnecessarily increases working capital."[1439] Noting that DTE appears to rely on past practice for projecting Taxes Payable, the Attorney General contends that past practices should be rejected if not adequately justified, as is the circumstance here.

In its reply brief, DTE reiterates that its approach is consistent with GAAP "and it is uncontroverted that DTE Electric's approach conforms to the tax expense calculation method that was approved in the Company's prior rate cases, including the most recent rate case, Case No. U-21534."[1440]

This PFD finds that for purposes of this rate case, the Company's calculation, which it states is consistent with GAAP and prior rate case calculations, should be accepted. Should the Attorney General seek an adjustment to this item in a future rate

[1438] 4 Tr 3154.
[1439] Attorney General brief, 137-138.
[1440] DTE reply, 10.

case, she should provide more support regarding why the Company's approach is incorrect or unreasonable.

Lastly, the Attorney General recommended an increase of $100 million to shift PTMM costs from capital expenditures to a regulatory asset. As discussed in detail elsewhere in this PFD, the recommendation regarding PTMM expenditure deferral was rejected.

N. Rate Base Summary

This PFD estimates that the recommendations discussed above result in a projected rate base of approximately $23,035,019,000.

VI.

COST OF CAPITAL

The rate of return component of the revenue requirements determination is designed to meet the constitutional and statutory standards entitling the utility to a fair rate of return on its investments that serve the public. To determine the rate of return to use in setting rates, it is customary to start with the development of an appropriate capital structure, and then to evaluate the appropriate costs to assign to each element of the capital structure. The appropriate capital structure is discussed in subsection A below, the cost of debt is discussed in subsection B, and the cost of equity capital is discussed in subsection C.

The rate of return used to set rates is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that

component by the cost rate for the component. The weighted cost rates for each component are then added to determine the overall rate of return.

A. Capital Structure

The capital structure used for ratemaking is composed of long-term debt, preferred stock, and common equity capital, along with short-term debt and other items such as deferred taxes that reflect sources of financing available to the company. Only long-term debt, preferred stock, and common equity capital are considered part of a utility's "permanent" capital, and it is common for capital structures to be shown in exhibits on both a "permanent" basis and on a ratemaking basis. The Commission has previously explained that its goal in selecting a utility's capital structure is to strike an appropriate balance between debt, with its higher risks but lower tax burdens, and equity capital, with its lower risks but higher expense and tax burdens.[1441]

After several years of proposing a balanced capital structure comprised of 50% debt and 50% equity, in this case, DTE proposes to adjust its permanent capital structure to increase the equity layer to 50.75% and decrease the debt layer to 49.25%, as shown in Exhibit A-14, Schedule D1.[1442]

Mr. Lepczyk testified that an increase in equity in the capital structure is "necessitated by the business and financial risks confronting DTE Electric," particularly the Company's expanded capital investment program (a proposed $7.9 million in investments through December 2026) which requires strong credit ratings to maintain the

[1441] See February 28, 2017 Order, Case No. U-17999, p. 63.
[1442] DTE does not issue preferred stock; therefore, only debt and equity are included in the Company's permanent capital structure.

financial soundness of the Company.[1443] Mr. Lepczyk also discussed the interplay between debt, equity, and risk, emphasizing the importance of a sound capital structure for both the Company and its customers, "as it ensures the continued viability of the company and provides access to capital at lower rates."[1444]

Ms. Nelson elaborated, stating that the most common approach to determining an appropriate capital structure is to use the utility's actual capital structure, particularly in cases where the utility: "(1) issues its own debt, (2) has its own credit rating, and (3) its actual capital structure is within industry standards and practice."[1445] According to her, DTE issues its own debt and has its own credit rating, leaving only the question whether the actual capital structure "is within industry standards and practice." Quoting from a publication by the National Association of Regulatory Utility Commissioners (NARUC), Ms. Nelson highlighted that "*capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs*."[1446] Further, Ms. Nelson pointed to James C. Bonbright's, *Principles of Public Utility Rates*, (1960) pp. 243-244, which indicates that hypothetical capital structures should only be used when actual capital structures are "clearly unsound" or "extravagantly conservative."[1447]

Lastly, Ms. Nelson compared DTE's proposed capital structure to the capital structures of the peer companies in her proxy group, as presented in Exhibit A-14,

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[1443] 4 Tr 2909-2911, 2913.
[1444] 4 Tr 2911.
[1445] 4 Tr 2997.
[1446] 4 Tr 2998, quoting NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), p. 12.
[1447] 4 Tr 2998.

Schedule D1.1, which shows that the Company's projected equity layer of 50.75% is consistent with the average equity ratio of 52.2% for the peer companies. As such, Ms. Nelson posited that DTE's proposed capital structure should be approved in this case.

Staff witness Ufolla, ABATE witness Walters, Mr. Coppola, and CUB witness Bandyk objected to the capital structure proposed by DTE. Mr. Ufolla testified that increasing the equity amount in the capital structure is more costly for ratepayers (more than three times the cost of debt), which may be appropriate under certain circumstances, but is not necessary here. According to Mr. Ufolla, DTE's credit ratings are strong, as shown in Exhibit A-18, Schedule H-1, and the Commission has consistently found that a balanced capital structure is appropriate for the Company.[1448] Mr. Ufolla further noted that DTE actually issued more debt than forecasted in its initial filing, which increased the debt layer by approximately 3%; however, given the Commission's preference for a balanced capital structure, Staff maintains that a 50/50 debt-to-equity structure remains appropriate for the Company.[1449]

Mr. Coppola similarly observed that DTE has proposed, and has had approved, a 50/50 capital structure in its last two rate cases, but advocates a higher equity layer in this case, despite the fact that the Company's risks and finances are generally unchanged since a balanced capital structure was last approved on January 23, 2025.[1450]

Mr. Coppola discussed the factors that support the continuation of a 50/50 capital structure including: (1) the Commission's clear directives to both DTE and Consumers Energy that a balanced capital structure is preferable to reduce costs to ratepayers while

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[1448] 5 Tr 4935-4936.
[1449] 5 Tr 4935.
[1450] 4 Tr 3483.

maintaining the companies' positive credit metrics; (2) DTE's strong funds from operations (FFO) to debt ratio and positive credit ratings; (3) equity contributions to DTE from DTE's parent company; (4) the favorable regulatory climate in Michigan, which has consistently awarded above-market ROEs; and (5) the equity ratio in the Attorney General's peer group is approximately 42.5%.[1451]

Mr. Coppola opined that DTE did not present a compelling case for increasing the equity amount in its capital structure, pointing out that DTE, like other utilities engaged in large capital programs, has not had any difficulty borrowing funds. Specifically, he noted that in the past three years, the Company has raised $2.7 billion in debt capital at competitive rates.[1452] Mr. Coppola also disputed the claim that the Company's peer utilities have a 52% equity ratio, testifying that "[t]he debt and equity balances used in the calculation of the 52% equity ratio appear to be at a single point in time at the end of 2023."[1453] According to Mr. Coppola, this is unreliable because debt and equity balances change throughout the year and over time due to seasonality of sales and the retirement of long-term debt. As such, "[a]n appropriate calculation of equity and debt balances and the resulting equity ratio needs to be done over multiple quarter-ended balances."[1454] He added that the Company's peer group contains a number of smaller utilities that tend to require higher equity levels, and the source DTE used in Exhibit A-14, Schedule D1.1, S&P Global, reports debt and equity balances of subsidiary companies, as set by

[1451] 4 Tr 3483-3484.
[1452] 4 Tr 3485-3486.
[1453] 4 Tr 3486.
[1454] Id.

management, under Generally Accepted Accounting Principles "and not balances and equity ratios set by regulatory agencies."[1455]

Next, Mr. Coppola discussed recent financial and credit reports from S&P, Moody's, and Fitch, all of which indicate a favorable outlook for DTE within Michigan's supportive regulatory environment. He also discussed the Company's recent FFO to debt ratios, explaining that adjusting the ratio for his recommendations in this case still results in a FFO to debt ratio of 22.6%, above the 21% threshold for a downgrade noted by Moody's.[1456]

Mr. Walters also observed that DTE's proposed equity ratio is significantly higher than that of ABATE's proxy group, as shown in Exhibit AB-11, indicating that "DTE Electric has less financial risk compared to the proxy group."[1457] He also cited the Commission's recent and consistent findings that a balanced capital structure is appropriate for Michigan's largest investor-owned utilities.

Mr. Bandyk took issue with Ms. Nelson's claim that a utility's authorized capital structure should be aligned with its actual capital structure, observing that the Commission has most recently found the reverse: that the authorized capital structure should dictate actual capital structure.[1458] Mr. Bandyk explained that defining an optimal capital structure involves weighing the relative risks and related costs of debt and equity with a goal of "determine[ing] the point at which the cost of increasing the firm's cost of

[1455] 4 Tr 3487.
[1456] 4 Tr 3488-3491.
[1457] 4 Tr 3295.
[1458] 4 Tr 4739.

capital by adding more equity does not outweigh the additional financing costs of adding more debt, and vice versa."[1459]

Based on his analysis of the interest coverage ratio, shown in Exhibit CUB-9, Mr. Bandyk concluded that DTE could reduce both its equity ratio and ROE while maintaining its current credit ratings from Moody's, Fitch, and S&P.[1460] Accordingly, Mr. Bandyk recommended that the Commission reaffirm that the 50/50 debt to equity ratio is appropriate for DTE.

In rebuttal, Mr. Lepczyk reiterated that DTE is planning capital additions of over $7.9 billion from January 2024 through December 2026 and that a reasonable capital structure during this period is essential to the Company's financial strength.

Ms. Nelson responded to Mr. Coppola's and Mr. Walters' comparisons of DTE to utility peer companies, explaining that measurement at the holding company level is inapt because "[c]apital at the holding company level finances a variety of business segments (both regulated and unregulated) each with different risk profiles and return requirements."[1461] As such, the proper comparison "is to the capital structures that finance the proxy companies' regulated electric operations."[1462]

In response to Mr. Bandyk's interest coverage ratio analysis, Ms. Nelson objected for several reasons, primarily: (1) the ratio Mr. Bandyk used is not used by rating agencies for the utility sector; and (2) even if it were used in the utility sector, CUB's recommendations for ROE and capital structure would result in an interest coverage ratio

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[1459] 4 Tr 4740.
[1460] 4 Tr 4741-4742.
[1461] 4 Tr 3121.
[1462] 4 Tr 3122.

in the A3 credit rating range, whereas DTE is rated A2. According to Ms. Nelson, DTE's capital structure and ROE recommendations result in an interest coverage ratio in the lower half of the A2 range as used by Mr. Bandyk.[1463]

This PFD agrees with Staff and the intervenors that DTE has not presented a persuasive case for increasing the equity amount in the Company's capital structure. As several parties point out, for ratemaking purposes, the Commission has recently determined that a balanced capital structure is reasonable and appropriate for both DTE and Consumers. Second, DTE's significant capital investment program is not new, and the Company has had no difficulty in raising debt capital at favorable rates with a balanced capital structure. Moreover, as Mr. Coppola touched on in his testimony, the actual capital structure for DTE Electric, to some degree, is determined by its parent company, which may elect to infuse equity capital at any time. This particular concern is not addressed by either NARUC or in Mr. Bonbright's work, as quoted by Ms. Nelson.

B. Cost Rates

1. Long-Term Debt Cost Rate

Mr. Lepczyk testified that Exhibit A-14, Schedule D2, was used to calculate the Company's projected weighted average long-term debt cost as of December 31, 2026, starting from the actual 2023 debt balance and incorporating known and measurable changes through 2026. These changes included planned 30-year fixed-rate bond issuances in 2025 and 2026 (based upon projected 30-year U.S. Treasuries with a 119

[1463] 4 Tr 3122-3123.

basis point spread added), resulting in a projected weighted average long-term debt cost of 4.24% by the end of 2026.[1464]

Mr. Ufolla explained that the difference between Staff's and the Company's recommended long-term debt rates stemmed from updates made during the audit process and revised interest rate projections for the 2026 bond issuance. Staff incorporated updated figures from DTE's May 2025 issuance, which raised the Company's projected rate from 4.24% to 4.29%. However, Staff adjusted the 2026 issuance rate to 5.44% (based on a 4.40% treasury rate and a 104-basis point spread derived from a one-year average of the Company's spread quotes from Scotiabank) resulting in a final recommended long-term debt rate of 4.27%.[1465]

Mr. Coppola adopted the long-term debt rate of 4.24% based upon Mr. Lepczyk's recommendation.[1466] Similarly, Mr. Walters did not take issue with the Company's 4.24% cost of long-term debt.[1467]

In rebuttal, Mr. Lepczyk disagreed with Mr. Ufolla's recommended long-term debt rate of 4.27%. He maintained that the DTE's projected 2026 issuance rate of 5.78% was proper, which was based on a 30-year treasury rate of 4.59% plus a 119 basis point spread. Using this rate along with actual 2025 issuances, the company updated its estimated weighted average long-term debt cost to 4.29% as shown in Exhibit A-45, Schedule KK1.[1468]

[1464] 4 Tr 2915-2916.
[1465] 5 Tr 4939-4940. See also Exhibit S-4, Schedule D-2.
[1466] 5 Tr 3492.
[1467] 4 Tr 3296.
[1468] 4 Tr 2928.

In its brief, DTE reasserts that its updated 4.29% long-term debt rate is reasonable without providing new argument or analysis.[1469]

Staff's briefing asserts that the Company simply updated its own projection while ignoring Staff's updated treasury projections; Staff further contends that DTE failed to produce testimony or evidence to dispute Staff's proposed 4.27% rate.[1470] The Attorney General's brief reiterates that Mr. Coppola accepted the Company's original projection of 4.24%.[1471]

The Company's reply merely reiterates its initial briefing.[1472] Staff's reply also provides no further argument on this topic, but the Attorney General's reply brief acknowledges the Company's updated 4.29% recommendation and states that the Attorney General agrees with this update.[1473]

This PFD recommends adopting Staff's proposed long-term debt cost rate of 4.27% which benefits from updated information and projections, and it utilizes a spread derived from the average of the Company's last year of spread quotes from Scotiabank.[1474]

2. Short-Term Debt Cost Rate

Mr. Lepczyk explained that the short-term debt interest rate was calculated by adding a 20 basis point spread to the 1-month short-term index, which was 4.31% as of January 2025, resulting in a rate of 4.51%.[1475] Due to market volatility and uncertainty

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[1469] Consumers brief, 126.
[1470] Staff brief, 122-123.
[1471] Attorney General brief, 75.
[1472] DTE reply, 111.
[1473] Attorney General reply, 39.
[1474] 5 Tr 4940.
[1475] 4 Tr 2917-2918.

around future Fed rate changes, the Company opted to use the currently known rate. Mr. Lepczyk included $1.3 million in facility fees costs (equating to 0.24% of the cost of short-term debt) and added that to the 4.51% rate to calculate a total cost of short-term debt of 4.75%.[1476]

Mr. Ufolla explained that the difference in short-term debt rate recommendations between Staff and DTE was due to differing projections of the 2026 Short-Term Overnight Financing Rate (SOFR). While the Company used a projected SOFR of 4.31% plus a 20 basis point spread and 24 basis points in credit fees for a total of 4.75%, Staff used a lower projected SOFR of 3.41% from S&P Global for 2026, resulting in a total cost of 3.85% using the same spread and fees.[1477]

Mr. Coppola proposed a short-term debt rate of 3.91%. He testified that the lower 3.91% short-term debt rate was based on a revised forecast provided by DTE in response to a discovery request, which cited a projected decline in the Federal Funds rate for 2026. This revised rate, down from the originally proposed 4.75%, was expected to reduce the Company's forecasted interest costs by $4.8 million on $563 million of short-term debt.[1478]

In rebuttal, Mr. Lepczyk disagreed with the recommended short-term debt rates proposed by Witnesses Ufolla and Coppola; he opined that they were based on overly optimistic forecasts of Federal Reserve rate cuts. Instead, he supported using the current known rate of 4.69%, which was based on DTE's actual 2025 borrowing rate of 4.45% plus 0.24% in credit facility fees, due to ongoing market volatility and uncertainty.[1479]

[1476] 4 Tr 2918; see also Exhibit A-14, Schedule D3.
[1477] 5 Tr 4940; see also Exhibit S-4. Schedule D-3.
[1478] 4 Tr 3493.
[1479] 4 Tr 2928.

In briefing, the Company repeats its support for its proposed 4.69% cost rate for short-term debt.[1480]

Staff's brief rejects DTE's criticism that Staff used projected rates, asserting that the use of projected interest rates better aligns with the test year and has been regularly used in past cases with the Company offering no compelling reason to simply use the current rate.[1481] Accordingly, Staff repeats its proposed 3.85% rate based on projected interest rates.

The Attorney General's briefing supports her proposed 3.91% rate asserting that it was based upon the Company's responses to discovery and reflects the expected market rate for short-term borrowing in 2026.[1482]

The Company's reply brief repeats the points made in its initial brief.[1483] Staff's reply provides no further argument, and the Attorney General's reply reiterates her disagreement with the Company's projection and restates her proposed 3.91% rate highlighting recent Fed rate cuts.[1484]

This PFD recommends adopting Staff's proposed short-term debt cost rate of 3.85% which utilizes a projected SOFR of 3.41% from S&P Global. This PFD views the use of a projected rate as a better practice for estimating rates in the test year than the Company's decision to simply use the rate currently in effect.

3. Return on Common Equity

[1480] Consumers brief, 127.
[1481] Staff brief, 123.
[1482] Attorney General brief, 75.
[1483] DTE reply, 112.
[1484] Attorney General reply, 39.

A utility's cost of common equity, generally referred to as the return on equity (ROE), is the return that investors expect to provide the utility with capital for use in its various operations. The cost of this capital essentially represents an opportunity cost; to induce investors to purchase a utility's common stock or bonds, there must be the prospect of receiving earnings sufficient to make the investment attractive when compared to other investment opportunities.

The criteria for establishing a fair rate of return for public utilities is rooted in the language of the United States Supreme Court cases *Bluefield Water Works Co v Pub Serv Comm of West Virginia*, 262 US 679; 42 S Ct 675; 67 L Ed 1176 (1923) and *Fed Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). In *Bluefield*, the Supreme Court explained:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[1485]

In turn, the Supreme Court provided further guidance in *Hope*, stating:

> The rate-making process under the Act, i.e., the fixing of just and reasonable rates, involves a balancing of the investor and the consumer interests. . . . [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By

[1485] *Bluefield*, 262 US at 692-693.

> that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[1486]

The Commission has recognized and adopted the principles announced in *Bluefield* and *Hope* by explaining that the rate of return "should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise."[1487] The Commission also stated that any determination of what is fair and reasonable "is not subject to mathematical computation with scientific exactitude but [rather] depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[1488]

DTE, Staff, the Attorney General, ABATE, and CUB undertook the typical ROE analyses, including discounted cash flow (DCF), the capital asset pricing model (CAPM), risk premium (RP), with the Company including its analysis and results from the empirical CAPM (ECAPM), an approach that this Commission, like most commissions, has rejected. Some parties also provided a comparison of commission-authorized ROEs over the past few years. In addition, the parties presented extensive testimony and rebuttal testimony criticizing the various inputs and approaches used by DTE and others in developing their respective recommendations.

[1486] *Hope Natural Gas Co*, 320 US at 603 (quotation marks and citations omitted).
[1487] Case No. U-18370, Order, April 12, 2018, p. 30.
[1488] Case No. U-18370, Order, April 12, 2018, p. 30 (citing *Meridian Twp v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955)).

Beginning with its May 8, 2020 order in Case No. U-20561 the Commission authorized an ROE for DTE of 9.90%, a 10 basis-point reduction from the ROE authorized in DTE's previous rate case, Case No. U-20162.[1489] Since that time, in Case Nos. U-20836, U-21297, and U-21534, the Commission has consistently found that a 9.90% ROE for DTE is reasonable and consistent with the standards articulated in *Hope* and *Bluefield*, discussed above.

Turning to the presentations in DTE's last rate case, Case No. U-21534, compared to the recommendations presented in the instant case, the following is instructive:

Party	U-21534		U-21860	
	ROE Range	Recommendation	ROE Range	Recommendation
DTE	10.20-11.1%	10.5%	9.90-11.60%	10.75%
Staff	9.30-10.30%	9.90%	9.40-10.40%	9.80%
Attorney General	9.26-10.57%	9.85%	9.80-9.97%	9.85%
ABATE	9.20-10.10%	9.60%	9.0-10.0%	9.50%
CUB	8.53-9.90%	9.30%	8.91-9.90%	9.40%

First, leaving aside DTE's outlier recommendation, all other ROEs advocated by the parties here are either identical, or within 10 basis points, of the recommended ROEs presented and evaluated by the Commission less than a year ago. And, except for the Attorney General's recommended range from the previous rate case, the results of the various analyses undertaken by Staff and intervenors are again remarkably similar.

[1489] Notably, since 2020, the ROEs that have been authorized by the MPSC for most gas and electric utilities are at or near 9.90%.

Given the near identical results in both ranges and ROE recommendations, coupled with the short time since DTE's ROE was last authorized, this raises a question whether any change to DTE's ROE is justified. This PFD finds that it is not, despite the hundreds of pages of testimony and extensive arguments over proxy companies, appropriate betas, adjustments for financial risks, analytical flaws, or the comparability of ROEs authorized by other utility commissions.

In addition, this PFD notes that the Commission is currently considering a PBR mechanism for both DTE and Consumers in Case No. U-21400, and is evaluating comments and reply comments on appropriate incentives and disincentives for improved reliability and performance. Because implementing such a mechanism may impact ROE in the future, this PFD finds that maintaining the status quo is appropriate, and consistent with the principles set out in *Hope* and *Bluefield*. Accordingly, this PFD recommends that DTE's current ROE of 9.90% again be approved for the test year.

C. Overall Rate of Return

Based upon the foregoing discussion, this PFD recommends that the Commission adopt a capital structure of 50% debt and 50% equity, along with a long-term debt cost ratemof 4.27%, a short-term debt cost rate of 3.85%, and a return of equity of 9.90% resulting in an estimated overall weighted after-tax cost of capital of 5.64% as shown in Appendix D to this PFD.

VII.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) constitutes the difference between a company's operating revenue at current rates and its operating expenses including depreciation,

taxes, and allowance for funds used during construction (AFUDC). Adjusted net operating income (ANOI) includes the ratemaking adjustments to the recorded test year, NOI for projections, and disallowances.

Disputes regarding ANOI-related items are broken out by category and discussed below.

A. Sales Forecast, Projected Operating Revenue, and Other Operating Revenue

Mr. Leuker presented detailed testimony on DTE's sales and peak demand forecasts for each customer class, noting that the Company's forecasting standards and forecasts are quite accurate, and that normalized sales forecast accuracy for 2023 was 99.3%, as shown in Exhibit A15, Schedule E5.[1490]

Ms. Uzenski presented DTE's projected sales revenue, which includes Electric Sales revenue, and Base Fuel and Purchased Power revenue as shown in Exhibit A-13, Schedule C3. Ms. Uzenski also supported other Operating Revenues, which includes late payment charges, miscellaneous service charges, shared asset revenue, and other miscellaneous revenue.[1491] Staff adjustments and other recommendations are discussed below

1. Sales and Customer Count

Staff proposed two adjustments to the Company's forecasts. First, Mr. Hansen discussed unregistered meters, generally describing them as meters installed at various residential or commercial locations and recording energy usage but not properly tied to a customer account; therefore, no customer is billed for energy usage.[1492] According to Mr.

[1490] 3 Tr 1327-1335, 1336,
[1491] 4 Tr 2421-2422.
[1492] 5 Tr 5176-5177.

Hansen, the Company reported the unregistered meters issue to Staff in November of 2024, explaining that there were, at that time, approximately 5,421 unregistered electric meters - some dating back to 2017 - on which the Company's Advanced Metering Infrastructure (AMI) meters transmitted and demonstrated actual usage data. This recorded usage, however, went unbilled.[1493] Staff characterizes the Company's failure to find and register these meters as unfair and unreasonable, especially considering that the number of such meters is increasing.[1494]

The Company provided updates to Staff in January 2025, April 2025, and July 2025, on its efforts to address the unregistered meters.[1495] In January 2025, the Company reported a total of approximately 5,800 unregistered meters.[1496] DTE also provided a response in audit indicating that accurate calculations of lost sales cannot be determined until a meter is associated with a customer account, and usage for that customer, can be established. However, the Company has distinguished between residential and commercial customers based on meter type in its effort to locate the unregistered meters; therefore, estimates of lost sales based on class are possible.[1497]

As noted above, the lost revenue associated with energy usage recorded by unregistered meters gave rise to concerns by Staff regarding the accuracy of the Company's line loss factor, sales forecast, deliveries forecast, uncollectible expenses, and information included in the Company's power supply cost recovery plan. Accordingly, consistent with Mr. Hansen's testimony, Mr. Ausum recommended that the residential

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[1493] 5 Tr 5177; Exhibit S-22.4.
[1494] 5 Tr 5236.
[1495] 5 Tr 5177; S-22.4
[1496] S-22.4, p. 14
[1497] S-22.0, p.11

electric deliveries forecast be increased by 24,159,596 kWh, and the commercial deliveries forecast be increased by 5,005,610 kWh.[1498]

Regarding customer count, Mr. Ausum also recommended that the residential customer forecast for the 2026 test year be increased by 3,944 customers and the small commercial and industrial customer forecast be increased by 735 customers.[1499] Next, Mr. Ausum described how Staff adjusted the customer count and sales forecast for the test year, as shown in detail in Exhibit S-27.1.[1500] Mr. Ausum's recommendations were then incorporated into Staff's present revenue calculation presented by Mr. Isakson.

DTE did not present rebuttal in response to Staff's recommended adjustments related to unregistered meters, nor did it address this issue in briefing. In its brief, Staff reiterated Mr. Ausum's testimony adjusting the test year forecast of deliveries and customers to account for usage by unregistered meters.[1501]

After reviewing the record, this PFD agrees with Staff that it would neither be fair nor reasonable for the costs associated with unregistered meters to be recovered from the Company's customers that are neither responsible for the energy usage associated with the unregistered meters nor the actions of the Company in failing to properly track and account for the meters and associated energy usage. The Company is responsible for lost sales attributed to unregistered meters.

The adoption of the Staff adjustments incorporating the data and usage on unregistered meters in sales and customer count ensures that the Company shoulders

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[1498] 5 Tr 5235; Exhibit A-15, Schedule E1, p. 1.
[1499] 5 Tr 5236.
[1500] 5 Tr 5236.
[1501] Staff brief,132-133

the costs associated with unregistered meters, consistent with the reasonableness and prudence standard required by MCL 460.6j(6). Having reviewed the record, this PFD finds the adjustments recommended by Staff for line loss, deliveries forecasts, and customer count forecasts are reasonable based on the data in Exhibit S-22.0, pages 10-11.

2. Other Revenue

In addition to the adjustment to present sales for unregistered meters, discussed by Mr. Hansen and Mr. Ausum, Mr. Isakson recommended an increase to present revenue (net) of $2.693 million to reflect an increasing historical trend in other operating revenue, noting that "over the last three years the Company has been collecting increasing revenue in late payment, miscellaneous service, and rent (FERC accounts 450,451, and 454, respectively). The Company's other revenues (FERC account 456) have trended lower over that same period."[1502] Mr. Isakson presented his calculation in Exhibit S-3, Schedule C3, p. 2.

In response to Mr. Isakson's recommendation to increase other revenue to reflect recent historical trends, Ms. Uzenski explained that Other operating revenues consist of various charges "that are impacted by customer payment patterns and the level of customer service requests. Such impacts could result in increased or decreased revenue on a year-over-year basis."[1503] She added that because of this variability, the Company used the same 2023 historical revenue amount for its test year projection, "consistent with the methodology used in prior rate cases."[1504]

[1502] 5 Tr 4903.
[1503] 4 Tr 2495.
[1504] Id.

In briefing, Staff reiterates that it has identified trends in other revenues that it expects to continue into the test year; thus, it is appropriate to include Staff's adjustment as it more appropriately reflects test year present revenue. DTE's brief relies on Ms. Uzenski's rebuttal.

This PFD is not persuaded that Staff's adjustment to Other operating revenues should be adopted. While Mr. Isakson provided an example of this purported trend from the Company's annual report, citing an increase of $1,060,082 in late payment revenue from 2022-2024, the other FERC account changes are not included in either testimony or Staff exhibits. While this PFD agrees that a persistent upward (or downward) trend in certain components of Other revenue may support a departure from past practice in forecasting, Staff will need to provide more detailed evidence to demonstrate that this is in fact the case.

3. Rate Case Reporting

With respect to deliveries, customer count, and peak demand forecasts in rate cases, Mr. Ausum testified that Part III, Attachment 3(1) of the rate case filing requirements, included here in Exhibit S-27.3, should be augmented with additional information. Specifically, Mr. Ausum explained that in DTE's next general rate case, the Company should provide actual historical customer class sales, number of customers, and monthly use per customer with the rate schedule sales. According to Mr. Ausum, "[t]his addition would prove useful because the Company forecasts deliveries and customers on a customer class level basis, and the actual historical class level deliveries

and customers are the major inputs to the forecasting models[.]"[1505] He added that the Commission should direct the Company to include additional months of historical sales and customer counts in its filing attachments if, as was the case here, DTE selects an historical year that is more than three months before the date its next application is filed.[1506]

In rebuttal, Mr. Leuker objected, stating that Staff's recommendations exceed the recently revised requirements for filing applicable to all utilities.[1507] Witness Leuker closed by offering that "[t]he Company is willing to provide its forecasting model inputs as workpapers if desired by the Commission in its next Rate Case Filing."[1508]

In its brief, Staff reiterated Mr. Ausum's testimony on what the Company should include in its future general rate case filings, as well as the Company's rebuttal.[1509] Staff argues that the requested data are the direct inputs to the load and customer forecasting models, and it is important that intervenors in the case are able to access those inputs in a format that is available to all parties.[1510] Staff contends that its recommendation for more data in future rate cases is simply an attempt to improve the efficiency of the rate case auditing process.[1511]

Staff declares itself amenable to Mr. Leuker's offer to include all load and customer forecasting inputs as workpapers in all cases going forward, provided this includes the Company's Itron project files, as well as separate Microsoft Excel or comma separated

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[1505] 5 Tr 5238.
[1506] 5 Tr 5239-5240.
[1507] 3 Tr 1378
[1508] 3 Tr 1379
[1509] Staff brief, 208-210
[1510] Staff brief, 210
[1511] Staff brief, 210-211

value (csv) files that allow intervenors without access to Itron's proprietary software the ability to assess the forecasting inputs and construct their own models if needed.[1512]

Therefore, Staff recommends that the Commission direct the Company to include the Itron project files related to the load and customer forecast as workpapers in all future cases. Additionally, the input data contained within those project files should be included separately in a universally accessible manner, subject to future protective orders.[1513]

In its reply brief, the Company reiterates its position that Staff's recommendations are unduly burdensome, noting that the Company had instead proposed producing its forecasting model inputs as workpapers in its next general rate case filing.[1514] The Company also reiterated its concern that Staff's recommendation to modify the rate case filing requirements would seem to "extend to all Michigan utilities" and "[t]herefore, any changes should be made through the appropriate regulatory docket to allow all utilities and interested parties to have a voice."[1515] The Company also noted Staff's amenability to the Company's proposal as documented in Staff's initial brief discussed above.

Having reviewed the record and the additional information requested by Staff and agreed to by the Company, this PFD concurs that DTE should include the Itron project files related to the load and customer forecast as workpapers in all future cases. Additionally, the input data contained within those project files should be included separately in a universally accessible manner, subject to future protective orders.

B. Fuel and Purchased Power Revenue and Expense

[1512] Staff brief, 211
[1513] Staff brief, 211
[1514] DTE reply, 137-138
[1515] DTE reply, 138

Mr. Willis testified that the Company proposes to maintain its current PSCR base of 31.26 mills per kWh at the generation level and is proposing to update the loss factor in accordance with the method approved in Case No. U-21534.[1516] He noted that the PSCR base amount was first approved in Case No. U-15768 and has been maintained ever since in each of the Company's subsequent rate cases.[1517] According to Mr. Willis, applying a loss factor of 7.76%, results in a total PSCR base at the sales level of 33.69 mills per kWh. Because the power supply costs equal the power supply revenues, there is no projected under- or over-recovery.

Mr. Hanson recommended that the Company's line loss factor be updated to 7.73% to reflect DTE's unregistered meters, as discussed above.[1518] Staff notes that no party took issue with this recommendation in rebuttal; thus, Staff's proposal should be adopted.[1519] This PFD notes that DTE did not address this recommendation in its initial brief, and therefore finds that the line loss factor should be updated to 7.73%, as calculated by Staff.

Staff also recommends that the Commission require the Company to propose resetting the PSCR base in its next rate case in order to collect all projected PSCR expenses. According to Mr. Revere, the justification for including an adjustment in the calculation of uncollectible expenses (UCX) in the instant case to account for PSCR factor revenue is that it would not otherwise be included because the PSCR factor is assumed to be zero for the purposes of a rate case. Mr. Revere testified that "It is Staff's position

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[1516] 4 Tr 1726-1727; Exhibit A-13, Schedule C4.
[1517] 4 Tr 1727.
[1518] 5 Tr 5178.
[1519] Staff brief, 207.

that the PSCR factor should be used to minimize over- and under-recoveries throughout the year due to variations in revenues or costs compared to the plan."[1520] He explained that there is a mismatch between the way customers cause costs to be incurred and how they are collected, and in order to ensure costs are allocated in a way that matches the way they were incurred, and avoid the need to make adjustments to the UCX expense calculation, Staff recommends the Commission require the Company to propose resetting the PSCR base in its next rate case to match their projection of PSCR expenses. This would require an assumed PSCR factor on either present or proposed revenue calculation equal to the proposed change in the PSCR base, so that PSCR revenues will be the same in both.[1521]

In rebuttal, Mr. Willis recognized the challenges in accurately forecasting UCX in the context of a rate case and indicated that the Company is open to discussions on calculating the revenue basis for UCX calculations; however, DTE does not believe that resetting the PSCR base in the next rate case is appropriate. According to Mr. Willis, the Company acknowledges Staff's view that the PSCR factor should be a mechanism to manage over- and under-recovery – consistent with its historical purpose.[1522] Because the PSCR factor has been consistently in a narrow band around zero for most of the last 10 years, the Company asserts that resetting the base would not appear to lead to a meaningfully more accurate estimate of power supply expense.[1523]

[1520] 5 Tr 5304
[1521] 5 Tr 5305
[1522] 4 Tr 1776
[1523] 4 Tr 1777

Mr. Burgdorf testified that resetting the PSCR base would create a substantial additional burden for all parties in the case.[1524] Indeed, the requirements for rebasing the PSCR would be similar to repeating the work required for a PSCR case, with additional witnesses, new testimony and exhibits for both the historical test year and the future test year. According to him, resetting the PSCR may also create confusion between assumptions made in the rate case, and the PSCR Plan case for sales forecast, forecasted fuel and purchased power costs.[1525]

In its brief, DTE reiterates Mr. Willis' testimony proposing to maintain the current PSCR base of 31.26 mills per kilowatt hour at the generation level but to update the loss factor.[1526] The Company disagrees that Mr. Revere's recommendation to reset the PSCR base is necessary or appropriate, reiterating that rebasing the PSCR would not materially improve the accuracy of power supply expense estimates. Moreover, updating the PSCR base would effectively replicate a full PSCR case within a general rate case – a redundancy which would impose an unnecessary burden on the Company and intervenors.[1527]

In its brief, Staff reviewed the testimony on its proposal to reset the PSCR base and acknowledged that it is possible that the factor may yet return to the "relatively narrow band around zero," and waiting for more information may be prudent.[1528] Staff reasserted that 1% of PSCR costs is not an insignificant amount of costs, and the Company did not

[1524] 4 Tr 1778.
[1525] 4 Tr 2077-2078.
[1526] DTE brief, 152.
[1527] DTE brief, 152-153.
[1528] Staff brief, 157.

present the impact of the differing allocations, so the overall impact is not clear on the record.

In response to Mr. Burgdorf's claim that the amount of work that would be required to implement the recommendation would be significant, Staff states that it does not necessarily agree. However, upon review, Staff retracts its recommendation that the Company be required to propose resetting its PSCR base in its next rate case for the purposes of the instant case. Staff recommends instead that the Company continue examining the amount of PSCR costs flowing through the PSCR factor to determine whether the PSCR factor returns to historical trends or not, and Staff reserves the right to present a similar proposal in future cases should the data support it.[1529]

After reviewing the record, this PFD notes that Staff has retracted its recommendation regarding resetting the PSCR base in DTE's next rate case. Nevertheless, this PFD recommends the Commission adopt Staff's alternative recommendation and direct the Company to continue examining the amount of PSCR costs flowing through the PSCR factor to determine whether the PSCR factor returns to historical trends or not.[1530]

C. Operations and Maintenance Expense

As shown in Exhibit A-13, Schedule C5, the 2023 adjusted historical O&M expense reported by DTE was $1.173 billion, which the Company projected to increase to $1.393 billion in the 2026 test year. Disputes over O&M expense are discussed below.

1. Inflation

[1529] Staff brief, 157-158.
[1530] Staff brief, 158.

As discussed above, this PFD recommends inflation adjustments of 2.9% for 2024, 2.7% for 2025 and 2.4% for 2026, with no historical inflation adjustments. While this PFD attempted to make appropriate inflation adjustments to O&M expense, in some cases this was not possible due to time constraints. Adjustments were however made to incorporate the inflation rates recommended here in the following programs:

Steam Power Generation	($2,635,000)
Fuel Supply & MERC Fuel Handling	($119,000)
Nuclear Power Generation	($1,749,000)
Hydraulic Power Generation	($169,000)
Other Power Generation	($382,000)
Distribution	($4,165,000)
Customer Service	($1,347,000)
Regulated Marketing	($314,000)
Corporate Support	($23,545,000)
IT O&M Expense	($1,101,000)
Total	**($35,526,000)**

The Commission should make the appropriate adjustments, based on the inflation rates the Commission approves in its final order.

2. Steam and Hydraulic Power Generation O&M Expense (non-nuclear)

Ms. Guillaumin provided a detailed review of Steam and Hydraulic Power Generation O&M expense, including numerous normalization adjustments to 2023 actual

expense.[1531] Several of these adjustments were contested by Staff and the Attorney General.

Staff recommended reducing Steam Power O&M by $20.158 million and Hydraulic Power Generation O&M by $131,000 for Staff's inflation rates. Ms. Kindschy testified that a review of Exhibit A-13, Schedule B5.1, fn 7, indicated that several of the normalization adjustments DTE included were for projects that are one-time, or infrequent. To protect ratepayers from unreasonable O&M expenses that continue beyond the test year, in the event that DTE does not file another rate case next year, Staff divided O&M expense for one-time or infrequent projects by half, which totals $15.41 million of the $20.158 adjustment to Steam Power O&M.[1532]

Specifically, Ms. Kindschy recommended: (1) a reduction of $2,333,500 for the Belle River Unit 2 Turbine Support Structure Restoration, because this is a one-time project; (2) two reductions totaling $1,050,000 for the Belle River Unit 1 Operational Improvements Post Conversion because these are one-time or infrequent projects; (3) a $3.0 million reduction for the Belle River Unit 1 Boiler Cleaning that was delayed to 2027; (4) a $3.843 million reduction for Monroe Reliability Maintenance because many of the subprojects within this item are one-time or infrequent; (5) a reduction of $5.470 million for Belle River Fuel Handling, due to the planned conversion of the plant in 2025; and (6) a reduction of $4.372 million for Steam Generation Periodic Outage Normalization because the amount calculated is based on historical O&M to maintain all four Monroe units, but units 2 and 4 are slated for retirement in 2028, thus reducing both capital and

[1531] See, 3 Tr 647-659.
[1532] 5 Tr 5095; Exhibit S-15.1.

O&M costs during the process of retiring the plant. Ms. Kindschy added that neither actual historical spending on periodic outage O&M, or the Company's calculation in its previous case support DTE's projection in this case.[1533]

Mr. Coppola also recommended reductions to O&M expense in this category, including: (1) a reduction of $14.551 million for outage normalizations, economic reserves, excess obsolescence, and BESS tipping fees; (2) a reduction of $7.686 million for Monroe Reliability Maintenance; and (3) a reduction of $3.294 million for Monroe Coal Equipment Maintenance.[1534] Mr. Coppola explained that he updated Steam Generation O&M for 2023 to 2024, noting further that this is the first time DTE has made these sorts of normalization adjustments in a rate case. Mr. Coppola explained that outages, both planned, forced, and economic, occur every year, and DTE provided no reason for why it made normalization adjustments for these unpredictable occurrences. And he testified that the BESS tipping fees and excess obsolescence costs were unexplained and unsupported.[1535]

Turning to Monroe Reliability Maintenance and the normalization adjustment, Mr. Coppola stated that in discovery, when asked for details on these additional costs, DTE listed sootblower maintenance, coal mill inspections, blade restoration, and equipment cleaning, as shown in Exhibit AG-45. According to Mr. Coppola, these appear to be routine maintenance items that should already be included in base maintenance O&M.[1536]

[1533] 5 Tr 5995-5102.
[1534] 4 Tr 3528-3532.
[1535] 4 Tr 3529-3531.
[1536] 4 Tr 3531.

Lastly, for Monroe Coal Equipment Maintenance, Mr. Coppola testified that in discovery, DTE explained that once the MERC facility is shut down, all coal will be delivered by train, and that the coal dumper at Monroe will require an overhaul. According to Mr. Coppola, the Company did not disclose when MERC is expected to close, why the delivery method will affect the coal dumper, or how the costs were developed.[1537]

In rebuttal to Staff, Ms. Guillaumin testified that while Staff properly recognizes these one-time expenses, in order to ensure that all costs are recovered, the Commission should either approve the full requested amount, or provide half the amount in this case and half the amount in the Company's next rate case, including the time value of money.[1538]

Regarding Staff's other adjustments, Ms. Guillaumin countered: (1) the $5.47 million reduction for Belle River fuel handling O&M is not necessary because DTE has already reduced this O&M expense by 25% (although this was not explained well in discovery), and because Ms. Kindschy failed to recognize how the Belle River plant operates with regard to fuel handling for the other coal units that are not converting;[1539] (2) for the periodic outage adjustment of $4.372 million, DTE has already reduced its outage spending by $3 million below what it anticipates spending in the test year. She provided a detailed explanation for how DTE calculated periodic outage O&M in the instant case, and why the amount and calculation method appear to differ from historical amounts and the method used in DTE's last rate case.[1540]

[1537] 4 Tr 3532.
[1538] 3 Tr 667-668.
[1539] 3 Tr 668-672.
[1540] 3 Tr 675-678.

In response to the Attorney General, Ms. Guillaumin disagreed with his adjustments, noting that the great majority were simply removal of DTE's normalizations. Specifically, she countered that the periodic maintenance outages are not speculative, as Mr. Coppola suggested, but were listed and explained in her direct testimony. For the other outages, Ms. Guillaumin explained how the adjustments were calculated based on historical averages of number of shutdown hours.[1541]

She also explained the adjustments for obsolete inventory and BESS tipping fees, noting that the 2023 historical year provides substantial detail for the Company's adjustments, and Mr. Coppola's claim the costs should be completely disallowed because DTE did not provide the same level of detail for 2024 normalizations, is erroneous.[1542]

Lastly, Ms. Guillaumin opined that Mr. Coppola did not provide sufficient detail or reasoning to justify removal of Monroe Reliability Maintenance expense; he merely stated that these activities appear to be normal maintenance that is already included in O&M. She further explained that the maintenance activities listed in Exhibit AG-45 were deferred in 2023 and 2024, but that "[e]xecuting these planned activities in 2026 will allow the Company to restore maintenance to a regular schedule and will minimize incremental work required in the years following 2026."[1543]

The parties briefs generally track their respective witnesses' testimony. DTE repeats the testimony of Mr. Coppola and Ms. Kindschy as well as Ms. Guillaumin's rebuttal.[1544] Staff states that it stands by its adjustments, emphasizing that removing 50%

[1541] 3 Tr 680-682.
[1542] 3 Tr 682-683.
[1543] 3 Tr 685.
[1544] DTE brief, 155-157.

of costs for projects that are one-time or infrequent is a reasonable approach for both the Company and ratepayers. With respect to the Belle River Fuel Handling O&M expense, Staff states that "assuming the record supports" the Company's claim that it has already reduced labor O&M by 25%, Staff is recommending an updated adjustment of $3.52 million for this project.[1545]

The Attorney General responds to Ms. Guillaumin's rebuttal, reiterating that O&M expense should have returned to normal levels in 2024, and she continued to question the propriety of, and support for, DTE's normalization adjustments.[1546]

This PFD agrees with Staff's adjustments, as modified in its brief, to Steam and Hydraulic Generation O&M expense. First, as also discussed below, Staff's approach to adjusting one-time or infrequent O&M expense is reasonable and fair to ratepayers and to the Company. As Staff argues:

> This assumption [that O&M can be adjusted in DTE's next rate case] is predicated on DTE Electric filing another rate case shortly after the current one is concluded. Staff highlighted the ambiguity of potential new load which could ultimately impact the frequency of the Company's next rate case. (5 TR 5104-5105.) Second, DTE Electric's proposal to include what it considers the missing half of its O&M expenses for one-time projects assumes that the projections will be spent exactly as proposed in this case. Staff would argue that the actual amounts could be higher, lower, or not incurred at all for a variety of reasons, and thus, automatically including half of a projected amount in future rates is not reasonable.[1547]

Second, this PFD agrees with Staff that the outage normalization adjustment made by DTE is not consistent with historical adjustments, either for the amount or the method. And while this PFD has adopted some of the removals of normalization adjustments, as

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[1545] Staff brief, 145.
[1546] Attorney General brief, 101-106.
[1547] Staff brief, 143-144.

advocated by the Attorney General, this PFD finds the disallowances recommended for Steam Generation O&M should be rejected.

3. Other Power Generation O&M Expense

Ms. Guillaumin summarized Exhibit A-13, Schedule C5.5 for other power generation O&M, specifically in relation to DTE's peaker fleet and BWEC non-fuel O&M expenses, indicating that the expense projections through the test year included material and labor costs, which themselves include expenses for the Generation Optimization and Integrated Resource Planning teams.[1548] The exhibit shows total other power generation expense of $39,612,000 for 2006.[1549] Citing Ms. Uzenski's testimony, Ms. Guillaumin stated that DTE used composite labor and material inflation factors for 2024-2026.[1550] She further stated that there was an adjustment of $40.4 million from 2023 to remove a renewable energy program, the expenses for which are not included in this case, and a $0.7 million normalization increase for 2026 when BWEC equipment failures will no longer be under warranty.[1551]

Ms. Guillaumin also explained another $13.2 million in projected test year adjustments: $0.2 million for the retirement of 13 peaker units (River Rouge 11-1 through 11-4, Slocum 11-1 through 11-5, St. Claire 12-1 through 12-2, and Fermi11-3 and 11-4); $1.2 million to support Slocum BESS and Trenton Channel BESS operations; $3.6 million to support levelizing major periodic outage expenses for BWEC as part of its four-year major equipment maintenance cycle with the first scheduled outage in 2026; and $8.6

[1548] 3 Tr 659.
[1549] Exhibit A-13, Schedule C5.5, line 18. *See also* DTE brief, 154.
[1550] 3 Tr 659.
[1551] 3 Tr 659-660.

million for increased peaker maintenance.[1552] Ms. Guillaumin explained that peaker unit operation has increased in recent years, necessarily increasing the frequency of maintenance activities, and that this increase is forecasted to continue through 2026.[1553]

Staff witness Kindschy recommended two non-inflation reductions, $914,472 for Trenton Channel BESS O&M, and $4,302,500 from the peaker increased maintenance expenses.[1554] She testified that the BESS operation adjustment included expenses for Slocum BESS, which went into service in February 2025, as well as approximately half a year of expenses for Trenton Channel BESS. However, discovery from the Company showed that Trenton Channel BESS has a COD of December 2026, so it is unclear why this merits half a year of O&M expenses, and the $914,472 recommended reduction removes these expenses.[1555]

As for the $4,302,500 recommended reduction for peaker increased maintenance, these were all one-time projects or projects occurring at varied, non-annual, intervals. Staff halved the requested amount, reasoning that recovery for such projects should occur over a two-year period.[1556] Ms. Kindschy indicated that a longer period of time might be appropriate if exceptionally large utility growth occurs or if the pace of case filings increases due to data centers adding up to 7 GW of new load in DTE's service territory.[1557] In addition to the specific recommendations related to Trenton Channel BESS and peaker increased maintenance, Ms. Kindschy also testified regarding the overall generation-

[1552] 3 Tr 660-661.
[1553] 3 Tr 661.
[1554] 5 Tr 5102-5104, 5108.
[1555] 5 Tr 5102-5103.
[1556] 5 Tr 5103-5104.
[1557] 5 Tr 5104-5105.

related O&M expense inflation adjustment recommended by Staff, which resulted in a $295,000 recommended reduction for other power generation.[1558]

In response to Ms. Kindschy, Ms. Guillaumin testified that it would be problematic for the Company to include the other half of the peaker increased maintenance expense not permitted in this case. She requested that the Commission either approve full recovery in this case, or approve half recovery in this case and approve "the time value of money from 2026 through 2027, even if the expenses occur in the bridge period of the next case."[1559] Ms. Guillaumin did not respond to the proposed reduction in relation to Trenton Channel BESS, and her direct testimony only notes the 2023 retirement of five Slocum peakers to enable construction of Slocum BESS, that Slocum BESS was completed in 2025, and that Trenton Channel BESS has a forecasted 2026 COD.[1560]

Mr. Coppola recommended an O&M disallowance of $8,741,000 for the test year.[1561] He prepared Exhibit AG-49, including O&M expense based on DTE's 2024 actual expense, opining that the use of 2023 as the historic test year was outdated where the actual 2024 O&M expenses were available, and concluding that using 2024 as the basis for test year O&M projections "provide[d] a cleaner basis to arrive at a reasonable level of O&M expense."[1562] In his calculation, Mr. Coppola removed the $368,000 of historical adjustment for BWEC maintenance for the test year on the premise that most of the issues at BWEC should have been resolved after three years of operation, resulting

[1558] 5 Tr 5105-5106, 5108.
[1559] 3 Tr 667-668.
[1560] 3 Tr 545-546.
[1561] 4 Tr 3536.
[1562] 4 Tr 3533.

in maintenance "diminish[ing] going into 2026."[1563] From this, Mr. Coppola started with a 2024 O&M expense of $26,464,000; he applied inflation adjustments for 2025 and 2026; and he included some other adjustments of $13,230,000 to calculate a 2026 O&M projected expense of $41,087,000, which is a $637,000 reduction to DTE's expense.[1564]

In relation to the other adjustments of $13,230,000, Mr. Coppola took issue with the $3,562,000 BWEC normalization of periodic outage expense. According to DTE's own numbers, the projected 2026 major outage expense for BWEC are forecasted to be approximately $14 million, and then DTE has added one-fourth of those expenses to 2026 O&M expense as a normalization cost.[1565] Mr. Coppola opined that this adjustment fails to consider that if the plant is not operating, and is thus not incurring normal O&M expense during the periodic outage, this should offset most of the $14 million in costs. In support, he noted that DTE has not proposed similar adjustments for periodic major outages at its coal plants.[1566] Therefore, Mr. Coppola recommended removal of the $3,562,000 adjustment from forecasted 2026 O&M expense.[1567]

Mr. Coppola also recommended removal of $4,542,000 from DTE's 2026 projected peaker increased maintenance expense of $8,606,000.[1568] He took the position that higher maintenance costs for 2026 were already calculated as part of 2026 O&M

[1563] 4 Tr 3533-3534.
[1564] 4 Tr 3533-3535. In opining that DTE's O&M expense should be reduced by $60.444 million, Ms. York voiced an opinion similar to that of Mr. Coppola - that actual 2024 numbers should be used as the starting point for O&M projections, rather than inflating 2023 numbers. 4 Tr 3239-3247.
[1565] 4 Tr 3534-3535.
[1566] 3 Tr 3534-3535.
[1567] 3 Tr 3535.
[1568] 3 Tr 3535-3536.

expenses, and that the need for incremental adjustment is unknown because peaker unit demand is generally random and driven by hot weather.[1569]

In Mr. Coppola's view, only the Renaissance Unit 2 compressor blade crack, and the Dean Peaker Flex Seal replacement, together $4,063,000, were unusual and incremental to routine maintenance. The remaining $4,542,000 for peaker maintenance increase, along with the $3,562,000 he calculated for BWEC outage normalization, and the $637,000 reduction in historical adjustment for BWEC maintenance, comprise his recommended $8,741,000 test year reduction.[1570]

Ms. Guillaumin testified in response that $8.5 million of Mr. Coppola's $8.7 million reduction "is simply based on him inappropriately eliminating the Company's adjustments, with the balance attributable to his lowering of inflation rates."[1571] She defended the BWEC normalization adjustment by noting that the warranty on equipment at the facility has ended, so it is reasonable to assume a modest increase in expenses as a result.[1572]

In relation to Mr. Coppola's assertions that periodic outage costs are offset by cost savings from not running the BWEC, Ms. Guillaumin stated that O&M expenses increase during periodic outages, contending that the 2026 major outage cost will be more than $14 million, while the 2023 O&M cost for operation was less than $10 million. Additionally, while the plant is taken offline, disassembled, inspected, and maintenance performed, equipment must be tagged and other support work must also be performed.[1573] Unlike the coal-fired units that Mr. Coppola used as an example, where the individual unit

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[1569] 3 Tr 3535.
[1570] 3 Tr 3533-3536.
[1571] 3 Tr 690.
[1572] 3 Tr 691-692.
[1573] 3 Tr 692-693.

spending may vary but overall O&M spending at the fleet level remains consistent, BWEC is DTE's only combined cycle power plant, so the spending is what Ms. Guillaumin characterized as "lumpy," and in need of levelizing. As the only plant of its kind, BWEC's outage is not balanced by overall fleet spending.[1574] According to Ms. Guillaumin, the BWEC periodic outage O&M expense is reasonable, expenses reasonably increase during periodic outages, and Mr. Coppola's recommendation should be denied.

Similarly, Ms. Guillaumin rejected Mr. Coppola's view of the peaker increased maintenance adjustment, stating that the work done in 2024 to which Mr. Coppola compared the 2026 O&M expense was "barebones work," while the work performed in 2026 is to be of greater scope.[1575] She stated that peaker use in an individual year is not an indication of the maintenance cost incurred; the maintenance costs include years of wear and tear on equipment, which results in increased future maintenance. "The Company's peaker maintenance adjustment in the instant case is to support the need for these future maintenance activities."[1576] Ms. Guillaumin again opined that the adjustments should be permitted as necessary to safe and reliable operations at both the peaker plants and at BWEC.[1577]

In her brief, the Attorney General questions *why* Ms. Guillaumin believes that an increase in maintenance expenses will be needed for BWEC now that the equipment is no longer covered under warranty, given that BWEC is a new plant. The Attorney General asserts that Ms. Guillaumin provides no basis for this opinion and characterizes the

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[1574] 3 Tr 693-694.
[1575] 3 Tr 694-695.
[1576] 3 Tr 695.
[1577] 3 Tr 695.

proposed increase as completely speculative.[1578] Similarly, the Attorney General contends that Ms. Guillaumin's direct testimony provides no evidence to justify the higher BWEC periodic outage expense in 2026, and she does not address savings from idling the plant. Per the Attorney General, the only reason given for the higher forecasted O&M expense in discovery was due to inflation.[1579]

The Attorney General also notes that DTE has other natural gas fueled power plants that go through periodic outages, but these plants do not propose the same, unusual outage expense increase. As a result, there is no support for the "unusual" BWEC expense increase in this case.[1580]

The Attorney General also asserts that DTE's forecast is based on outdated numbers, and, in relation to the peakers' increased maintenance adjustment, she maintains that the need for "incremental adjustment is simply unknown."[1581] Review of discovery responses in relation to maintenance in 2024 indicates it was mostly routine and was already reflected in routine expenses. This issue was "discussed before with the Company deferring maintenance in 2023 and 2024 to boost the Company's bottom line and now wanting to do catch up maintenance in the projected test year by requesting higher expense levels."[1582] In sum, the Attorney General recommends disallowance of $8,741,000 for other power generation O&M expenses for 2026.[1583] She summarizes these points, and repeats her recommendation, in her reply brief.[1584]

[1578] Attorney General brief, 107.
[1579] Attorney General brief, 107-108, citing Exhibit A-54, Schedule UU4.
[1580] Attorney General brief, 108-109.
[1581] Attorney General brief, 106, 109.
[1582] Attorney General brief, 109-110.
[1583] Attorney General brief, 106-110.
[1584] Attorney General reply, 44-45.

In its brief, Staff recommends disallowance of $5,512,000 from other power generation O&M, first repeating Ms. Kindschy's recommended $917,471 reduction for Trenton Channel BESS because it will not be operating for most of 2026.[1585] Next, Staff recommends a $4,302,500 reduction to peaker increased maintenance on the basis that two years is a reasonable recovery timeframe for the one-time and infrequent O&M projects proposed.[1586] Additionally, using Staff's proposed inflation rates results in an additional $295,000 reduction.[1587] Staff rejects DTE's contention that a two-year spread of one-time and infrequent O&M expenses should be entitled to the time value of money on the deferred half, contending that the uncertainty of potential new load impacting the timing and size of DTE's next rate case filing and the fact that these are projections only, and not actual spending, do not warranted adjustment.[1588]

DTE's initial brief touches on its overall O&M calculation, as well as the inflation rates used in its projections. DTE otherwise relies on Ms. Guillaumin's testimony, contending that Mr. Coppola's recommendations "are not based on the operational realities of the Company."[1589] In relation to Staff's recommendations regarding splitting one-time expense recovery over two years, DTE asserts that it should either receive full recovery in this case, or the deferred half of the recovery should be given the time value of money for 2026 through 2027, "even if the expenses occur in the bridge period of the next case."[1590]

[1585] Staff brief, 139, 150-151.
[1586] Staff brief, 152.
[1587] Attorney General brief, 152-153.
[1588] Attorney General brief, 142-144.
[1589] DTE brief, 154, 157.
[1590] DTE brief, 155.

DTE goes into greater detail in its reply brief regarding the Attorney General's recommendations, but neither of DTE's briefs directly address Ms. Kindschy's recommendation for a $917,472 reduction in relation to Trenton Channel BESS O&M.[1591] Concerning the Attorney General's recommended $8,741,000 reduction, DTE asserts that it "rests on a selective rebuild of the Company's 2026 forecast from 2024 actuals and unilateral removal of adjustments that are necessary to reflect known and measurable conditions in the projected test year."[1592] Otherwise, DTE repeats the same points as raised in Ms. Guillaumin's testimony and its initial brief, also listing, in answer to the Attorney General's assertions that the BWEC periodic outage spending is unprecedented, other instances where periodic outages resulted in similar adjustments for steam units.[1593]

In reply, Staff reasserts all of its earlier arguments.[1594] Staff also clarifies its argument against paying value of money if one-time and infrequent projects are spread over two years, clarifying that: (1) O&M costs are projections, and the uncertainty of projections means that DTE will not incur expenses exactly as proposed; (2) there are undoubtedly one-time or infrequent projects where DTE did not make a special adjustment in the historical test year, and "[a]ny one-time projects in the historical test year would substitute for the other half of the O&M that DTE claims it should receive in a future rate case;" and (3) it is not reasonable to preapprove recovery of the other half of the O&M time-adjusted expenses without a complete review of all O&M expenses.[1595]

[1591] DTE reply, 149-151
[1592] DTE reply, 149-150.
[1593] DTE reply, 150-151.
[1594] Staff reply, 1.
[1595] Staff reply, 10-11.

Staff again notes that it is unknown what the addition of data centers and their need for additional load will do to the frequency and size of rate case requests going forward.[1596]

This PFD finds that Staff's adjustments should be adopted. As Staff points out, all projections are speculative as to both timing and amount, and any additional peaker maintenance expense would simply continue into the next year. It also appears that no one is contesting Staff's $917,472 reduction based on Trenton Channel BESS having a COD of December 2026, and, as a result, this PFD also recommends this reduction. Therefore, this PFD recommends a reduction of $5.512 million for other power generation O&M expense.

The other recommended reductions are a closer question. In Case No. U-21534, the Commission adopted a $3.01 million reduction recommended by Staff. There, Staff projected other power generation O&M on 2023 historical amounts, rather than using 2022 as the historical year; the Commission's order otherwise provides little guidance for this category of O&M in this case.[1597] That said, as discussed above, given the limited amount of time available to prepare this PFD, and the fact that not all expenses were updated to 2024, this PFD declines to adopt 2024 as the historical year for projecting O&M.

This PFD further finds the Attorney General's arguments persuasive and recommends disallowance of $3,562,000 for BWEC normalization of periodic spending because this expense is speculative. However, while the Attorney General's other

[1596] Staff reply, 11.
[1597] January 23, 2025 order in Case No. U-21534, p. 219.

concerns and recommendations appear valid, they also appear to stray into DTE's business decision making.

4. Midwest Energy Resources Company Fuel Supply Expense

Mr. Milo testified that the projected 2026 O&M expense for fuel supply and MERC's fuel handling total $6.26 million, based on adjusted 2023 historical costs and inflation factors supported by Ms. Uzenski.[1598] He added that there was an approximately $2 million reduction of MERC O&M expense because MERC was expected to cease operation in June of 2026.[1599] Mr. Milo also testified that the Company proposes to defer, as a regulatory liability, any O&M costs at MERC that continue to be recovered in rates above the actual amount incurred until rates are reset in a future case.[1600]

Ms. McMillan-Sepkoski testified that Staff recommends approving the proposed regulatory liability for MERC's O&M costs.[1601] Staff witness Kindschy testified that MERC's fuel handling O&M expense should be reduced by $92,000 based upon Staff's lower estimated inflation rates.[1602]

Mr. Jester explained that because MERC is scheduled to shut down operations in June of 2026, it is unreasonable to apply an inflation adjustment to preserve purchasing power, given the consistent decline in MERC's coal delivery volumes.[1603] Mr. Jester asserted that DTE overestimated MERC's O&M fuel handling expenses across the last three rate cases costing ratepayers approximately $1.3 million.[1604] He also testified that

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[1598] 3 Tr 729; see also Exhibit A-13, Schedule C5.2.
[1599] 3 Tr 729.
[1600] 3 Tr 730; see also the testimony of company witness Uzenski at 4 Tr 2486.
[1601] 5 Tr 4986.
[1602] 5 Tr 5105-5106.
[1603] 5 Tr 4770, 4771.
[1604] 5 Tr 4772.

the Company's proposed $2 million reduction of O&M for MERC fuel handling reflected the closure of MERC's business in June of 2026 instead of an adjustment for MERC's historical underspending.[1605] Mr. Jester ultimately recommended a disallowance of $1.7 million in O&M expenses for MERC fuel handling given the historical underspending and the inappropriate application of an inflation adjustment.[1606]

In rebuttal, Mr. Milo responded that using an inflation factor is a standard and reasonable method for projecting O&M expenses, especially for fixed costs at MERC, and that the Company further refined the projection with a significant "Other Adjustment" to reflect only the minimum necessary expenses such that inflation was effectively adjusted out of the expense.[1607] He criticized Mr. Jester for ignoring these adjustments and relying on the presence of inflation factors to argue for a disallowance of MERC's O&M expenses.[1608] Mr. Milo asserted that Mr. Jester's proposal to eliminate all projected 2026 O&M expenses at MERC is unreasonable because it seeks to penalize the Company for past overestimations rather than accurately estimating future costs for operating the facility.[1609]

Mr. Milo also confirmed that both he and witness Uzenski addressed MERC O&M spending proposing that any over-recovered costs be deferred as a regulatory liability.[1610] He recommended the Commission reject Mr. Jester's proposal to disallow $1.7 million in

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[1605] 5 Tr 4773 (citing the company's Exhibit A-13, Schedule C5.2, line 9, column (j)).
[1606] 5 Tr 4773.
[1607] 3 Tr 733.
[1608] 3 Tr 734.
[1609] 3 Tr 734-735.
[1610] 3 Tr 735.

projected MERC O&M expenses, emphasizing that the Company's forecast is reasonable and includes safeguards to prevent over-recovery.[1611]

In briefing, DTE repeats that it made an almost $2 million reduction in O&M to account for MERC's closure in June of 2026 and that the remaining $1.7 million O&M request is the minimum necessary to operate the facility.[1612] The Company maintains that MNSC's disallowance would unreasonably penalize the company for relatively minor past over-projections, and it argues that it responsibly proposed to defer as a regulatory liability any recovery for MERC O&M expenses above the actual amount incurred.[1613]

Staff's brief repeats the requested $92,000 disallowance for MERC's O&M expense based upon Staff's lower projected inflation rates.[1614]

In briefing, MNSC argues that Mr. Milo's claims about MERC's O&M expense projections are not supported by the data. MNSC points to Exhibit MEC-54 stating that the 2026 projections are nearly as high, or even higher in some categories, than the actual expenses for eight months of 2025, despite a projected 88% drop in coal shipments.[1615] MNSC concludes that the expense forecast is unreliable and inflated, making it an unreasonable basis for determining MERC's test year costs.[1616] MNSC rejects Mr. Milo's criticism that Mr. Jester's proposal penalizes the Company for past overcollections. Instead, MNSC asserts that DTE proposes no remedy for its past overcollections and

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[1611] 3 Tr 735.
[1612] Consumers brief,158.
[1613] Consumers brief,159.
[1614] Staff brief, 149.
[1615] MNSC brief, 150.
[1616] MNSC brief, 150.

states that the Company's request for a regulatory liability suggests that overcollection is at least somewhat likely again.[1617]

In its reply, the Company asserts that Staff's proposed inflation rates are significantly lower than the Company's and would inappropriately reduce projected expenditures.[1618] DTE argues that MNSC's proposal to disallow all O&M expenses because of past over projections is inappropriate and unlawful because it is essentially retroactive ratemaking.[1619] The replies filed by Staff and MNSC provided no further argument on this issue.

This PFD recommends approving the Company's MERC O&M expense and regulatory liability treatment, because such treatment can protect ratepayers from potential over-recovery. As provided above, this PFD has adjusted inflation rates and amounts for MERC. After these recommendations, this PFD does not view as necessary MNSC's proposed O&M disallowance and therefore declines to adopt it.

5. Nuclear Generation O&M Expense

Mr. Davis provided an overview of DTE's nuclear generation O&M expenses, referencing Exhibit A-13, Schedule C5.3, noting that adjusted expenses for the 2023 historical test period were $161.2 million. The adjusted forecasted O&M for the test period is $160 million.[1620] Mr. Davis explained the rate case adjustments used to arrive at the projected amount, including removing site security and radiation protection costs that appear in the nuclear surcharge; the Project Evaluation Review Committee (PERC)

[1617] MNSC brief, 151.
[1618] DTE reply, 150.
[1619] DTE reply, 153 n 33 (citing *The Detroit Edison Co v Public Service Comm,* 416 Mich 510, 523; 331 NW2d 159 (1982)).
[1620] 3 Tr 487-488, 516.

nuclear O&M project expenditures and PERC regulatory asset amortization; the portion of industry association fees reported as lobbying expenses; normalization adjustments for irregular expenses; and outage accrual adjustments.[1621]

Going into greater detail, Mr. Davis indicated that the $161.2 million for the adjusted historical test period consists of nuclear organization, i.e. baseline employee, services, and material expenses to run Fermi 2; PERC base expense, which is $15 million as determined in Case No. U-20561; amortization of the PERC regulatory asset as permitted by Case Nos. U-18014 and U-20561; regulatory assessments and dues; and refueling outage expenses.[1622] Mr. Davis elaborated on the regulatory assessments and dues paid, both discretionary and non-discretionary, and the benefits these provide.[1623] He added that refueling outage expense is comprised of actual refueling outage costs, refueling outage accrual, and refueling outage accrual reversals, which are levelized to prevent large fluctuations or financial swings between outage and non-outage years. He also explained how these amounts were determined, starting with the $1 million actual refuel outage expenditures and $23.6 million refuel outage accrual for 2023.[1624]

Mr. Davis continued his explanations, setting forth the $1 million refuel outage reversal for 2023, the outage accrual adjustment, and the 45 day duration of the RF23 outage in 2026.[1625] He also elaborated on Ms. Uzenski's testimony regarding the PERC amortization adjustment and the basis for the total PERC expense of $16.3 million

[1621] 3 Tr 487-490.
[1622] 3 Tr 490-493.
[1623] 3 Tr 492-498.
[1624] 3 Tr 499-501.
[1625] 3 Tr 501-502.

forecasted for the test year.[1626] Mr. Davis described the PERC O&M expenditures of $7.7 million for 2023, $30.5 million for 2024, $11.9 million for 2025, and $17.7 million for 2026, and the calculation of the forecasted amounts.[1627]

Mr. Davis provided additional details underlying the refueling outage planning, readiness, and demobilization project, and details for the desludge-torus project.[1628] He outlined the reactor feed pump turbine (RFPT) inspections project; the residual heat removal heat exchanger (RHR HX) coating project; force-on-force inspections, with the next inspection scheduled in 2025; the high energy line break (HELB) analysis; the independent spent fuel storage installation (ISFSI) and the ISFSI fuel characterization; the spent fuel pool (SFP) cleanup campaign; core shroud inspections; license renewal inspections; the feed water heater (FWH) bridging strategy project analysis; circulating water pump (CWP) refurbishments; and the Fermi 2 hydraulic control units (HCUs) one-time preventative maintenance.[1629] As previously stated, Mr. Davis presented total nuclear power generation O&M expenses of $160 million for the projected test period.[1630]

Referring to Ms. Uzenski's testimony, Mr. Davis noted that DTE's labor and material prorated inflation adjustments were applied as part of the projected adjustments.[1631] Mr. Davis also indicated that one of the rate case adjustments made was to increase the nuclear organization expense to restore Fermi 2 staffing levels by the end

[1626] 3 Tr 502-503.
[1627] 3 Tr 503-504.
[1628] 3 Tr 504-505.
[1629] 3 Tr 505-511
[1630] 3 Tr 511-512.
[1631] 3 Tr 501.

of 2026 to those considered safe and necessary from 2023, which was $4.1 million below long-term sustainable thresholds.[1632]

Mr. Coppola recommended a nuclear generation expense of $154,153,000, which is $5,845,000 less than DTE's expense forecast for the test year.[1633] He took the position that DTE used its 2023 actual expense as the projection basis, which Mr. Coppola viewed as outdated.[1634] Instead, Mr. Coppola used DTE's 2024 O&M expense amounts.[1635]

Mr. Coppola also removed the Company's historical adjustment of $4,861,000 for lower staffing levels because employee headcounts through June 2025 indicated current staffing levels remain below pre-2022 levels, and that the lower employee count would persist.[1636] Specifically, Mr. Coppola testified that the employee headcount at Fermi 2 decreased from 741 in 2022 to 709 in 2023, 708 in 2024, and 703 in June 2025, with the Company projecting an increase to 716 by the end of 2025, and to 720 by the end of 2026, which is still lower than the employees at the plant at the end of 2022. Based on this, Mr. Coppola assumed that "the nuclear operation participated in the Company's temporary cost reduction efforts in 2023 and reduced some staff members," that continued into 2024.[1637] Irrespective of this, the pattern left Mr. Coppola with the conviction that staffing would not be increased, and he removed the cost of increased staffing to calculate an overall nuclear generation expense.[1638]

[1632] 3 Tr 489-490.
[1633] 4 Tr 3536-3538, citing Exhibit AG-50, Exhibit AG-51, and Exhibit A-13, Schedule C5.3.
[1634] 4 Tr 3536.
[1635] 4 Tr 3537-3538.
[1636] 4 Tr 3537-3538.
[1637] 3 Tr 3537.
[1638] 3 Tr 3537-3538.

In rebuttal, Mr. Davis testified that Mr. Coppola's approximately $5.8 million proposed reduction was based on "a series of inappropriate conclusions."[1639] He summarized how Mr. Coppola had generated his numbers, and opined that the Company's projection of $160 million for the test period was reasonable and prudent regardless of the historical year used.[1640] Mr. Davis also clarified that nuclear generation employees did not participate in DTE's voluntary separation incentive program (VSIP), and DTE did not "purposely reduce Fermi 2 staffing in support of a short-term expense savings program," contrary to Mr. Coppola's assertions.[1641] Instead, DTE hired approximately 52 new employees and transferred another 8 from other areas in the Company to offset attrition. Mr. Davis indicated that DTE is actively recruiting to fill open positions at Fermi 2, which is consistent with the expenses approved in Case No. U-21534.[1642] The Company believes that the additional staffing is necessary for nuclear safety, and Mr. Davis opined that "[a]djusting a nuclear power plant's operating expenses and staffing levels using a one- or two-year snapshot would not be reasonable and would not be prudent."[1643]

Based on Staff's inflation rates Ms. Kindschy testified that Staff recommended a reduction of nuclear power generation O&M of $1,354,000.[1644] This $1.354 million reduction was again recommended in Staff's brief.[1645]

[1639] 3 Tr 516, 528-532.
[1640] 3 Tr 528-532.
[1641] 3 Tr 532.
[1642] 3 Tr 532-533.
[1643] 3 Tr 533.
[1644] 5 Tr 5106.
[1645] Staff brief, 149-150. Staff's reply brief does not appear to revisit the issue specifically, but generally reserves Staff's earlier objections, and states some general responses to DTE's assertions regarding O&M, overall. Staff reply, 1, 10-11.

The Attorney General, in her brief, reiterates the requested $5.8 million disallowance.[1646] She contends that Mr. Coppola's forecasted expenses based on DTE's actual 2024 O&M expenses are more accurate than Mr. Davis's continuing adjustments from the 2023 O&M expenses.[1647] She is unimpressed by DTE's assertions that its projected nuclear generation operating expenses are not outdated, and she dismisses the Company's use of the terms "risk" and "nuclear safety priority" to justify its projected expenditures.[1648] The Attorney General's reply brief raises the same points.[1649]

In answer to the Company's arguments that it intends to hire more people at Fermi 2, that those additional employees are critically needed, and that reduced staffing levels at Fermi 2 are unsustainable, the Attorney General points out that attrition has outstripped DTE's ability to hire for multiple years. Therefore, the problem is likely to continue, despite DTE's hiring intentions, and reducing projected expenses to recognize these reduced staffing levels remains appropriate.[1650] As a result of the adjusted expenses, the likelihood that DTE will not meet its hiring goals, and DTE's continued safe operation of the nuclear plant with fewer employees, the Attorney General maintains her recommended disallowance of $5,845,000 in O&M expense for 2026.[1651] The Attorney General makes the same recommendation in her reply brief.[1652]

DTE, in its brief, first outlines the overall nuclear power O&M expenses, the adjustments made to this amount, and the forecasted $160 million O&M expense for the

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[1646] Attorney General brief, 7.
[1647] Attorney General brief, 110-111, citing Exhibit AG-51.
[1648] Attorney General brief, 111.
[1649] Attorney General reply, 45-46.
[1650] Attorney General brief, 111-112.
[1651] Attorney General brief, 110-112.
[1652] Attorney General reply, 45-46.

test period, and responds to Mr. Coppola's recommended reduction by relying on Mr. Davis' testimony.[1653] In its reply brief, the Company also addresses Staff's recommended $1.354 million reduction based on Mr. Ufolla's proposed inflation rates, contending that the Commission has approved the Company's blended interest rate in the past, and that Staff's proposed inflation rates would "inappropriately reduce the Company's projected expenditures."[1654]

In relation to the Attorney General's arguments that DTE has faced difficulty filling open positions as a basis for disallowing spending for new hiring, DTE again relies on Mr. Davis's testimony regarding the need for 720 employees to reliably operate Fermi 2 in compliance with the plant's NRC operating license. DTE asserts that it has taken "a number of proactive steps to offset attrition," highlighting that Fermi 2 staff were excluded from the VSIP, that Fermi 2 has hired approximately 52 new employees, and DTE has transferred 8 employees to the plant.[1655] DTE asserts that the Attorney General has not rebutted the reasonableness of the staffing plan or demonstrated that the Company can operate Fermi 2 safely and reliably long-term at reduced staffing levels. DTE again asserts that safety and reliability necessarily remain overarching goals.[1656]

As an initial matter, this PFD agrees that DTE's nuclear O&M expense should reflect updated inflation rates, as discussed in detail above.

Turning to the Attorney General's recommended disallowance, largely related to staffing levels, this PFD finds DTE's explanation persuasive that the Company's current

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[1653] DTE brief, 159-160.
[1654] DTE reply, 154.
[1655] DTE reply, 154-155.
[1656] DTE reply, 155.

staffing level at Fermi 2 is insufficient, and that DTE is endeavoring to correct this situation, consistent with the requirements of its operating license.

6. Distribution Expense

DTE projects $505.513 million for the 2026 test year, based on normalized 2023 expense updated with inflation. Several parties took issue with the Company's projection.

a. Distribution Base O&M Expense

Mr. Coppola pointed out that DTE instituted a cost reduction initiative in 2023, to address a decline in earnings, thus lowering 2023 actual distribution O&M spending.[1657] According to Mr. Coppola, most of the spending cuts were reversed after 2023, and were added back via the Company's normalization adjustments, totaling $42.025 million for 2024, as shown in Exhibit AG-40.

Mr. Coppola opined that because not all of the expense reductions were reinstated in 2024, it was better to start with 2024 actual O&M, included, to develop the test year projection. First, Mr. Coppola recalculated the Storm Restoration O&M expense, using the 2020-2024 actual expense, updated for inflation, instead of using DTE's CDA approach. This resulted in a decrease of $12.044 million.[1658] As discussed above, CDA was rejected and the Attorney General's adjustment related to Storm Restoration should be adopted.

As for DTE's remaining normalization adjustments of $1.758 million for a hiring pause, $1.735 million for pausing purchases of materials and advertising, a $2.128 million reduction for consultants, and $576,000 for apprentice classes, Mr. Coppola testified that

[1657] 4 Tr 3519.
[1658] 4 Tr 3519-3520.

"if these pauses in spending and delayed hiring continued into 2024, they are no longer temporary."[1659] He therefore recommended a reduction, totaling $29.711 million, inclusive of his storm restoration CDA adjustment, to distribution base O&M expense.

Staff witness Rueckert objected to DTE's use of composite inflation factors and recommended a reduction of $3.223 million to distribution O&M.[1660]

Mr. Kryscynski disagreed with Mr. Coppola, pointing out that Mr. Coppola "assumes that just because the Company has been able to forgo an expense for a period of two years, it will be able to forgo that expense indefinitely."[1661] Mr. Kryscynski explained that while there was a short-term hiring pause, this cannot be sustained over a long period, and that more staffing in needed to respond to emergent needs and to implement new initiatives. For apprentice classes, he explained the long training time for overhead and underground workers, noting that there were only two apprentice classes in 2024, but the Company expects to have five classes in 2025 and 2026.[1662]

For the reduction in consulting expense, Mr. Kryscynski stated that "[c]onsultants allow the Company to flexibly support short term priority needs and temper the need to hire more full-time staff[,]" again noting that a reduction in this expense is not a reasonable long-term strategy.[1663] And for the pause in materials and advertising purchases, Mr. Kryscynski explained that the reduction in this expense, which is significantly related to safety communications during storm events, was possible due to reduced storm activity

[1659] 4 Tr 3521.
[1660] 5 Tr 5194-5195.
[1661] 3 Tr 1253.
[1662] 3 Tr 1254.
[1663] 3 Tr 1255.

in 2023. Again, he characterized this approach as unsustainable given the unpredictability of future storm activity.[1664]

Lastly, Mr. Kryscynski testified that Mr. Coppola's proposed disallowance of $12.044 based on CDA is inaccurately calculated as he omitted $1.495 for non-storm restoration expenses.[1665] He asserted that if the Commission adopts the Attorney General's removal of CDA from Restoration O&M, the proposed disallowance should be corrected to include the $1.495 million, resulting in a disallowance of $10.549 million.[1666]

In her brief, the Attorney General urges the Commission to "see through this charade[,]"[1667] pointing to discovery responses in Exhibit AG-69, which failed to confirm Mr. Kryscynski's rebuttal concerning the Company's ability to operate for two years with reductions in hiring, consultants, materials, apprentice classes, and advertising. The Attorney General points out that while the "financial pressures" the Company purportedly faced in 2023 and 2024 led to these reductions, DTE was still able to pay bonuses and incentive compensation to its employees in those years.[1668] DTE's brief reiterates Mr. Kryscynski's contention that simply because an expense is reduced for one or two years, does not mean that that reduction is sustainable in the long run.[1669]

This PFD agrees with the Attorney General in part, finding that the $2.128 million reduction in consultant costs should be adopted, because the Company did not adequately support these costs. However, the hiring, safety, and training portions of the

[1664] 3 Tr 1256.
[1665] 3 Tr 1256-1257; Exhibit A-13, Schedule C5.6.
[1666] 3 Tr 1257-1258.
[1667] Attorney General brief, 88.
[1668] Attorney General brief, 87-88.
[1669] DTE brief, 163.

Company's normalization should be included. While it is troubling that DTE reduced some of these expenses in 2023 and 2024, yet was still able to pay bonuses, this PFD agrees that with the many new initiatives related to distribution operations, additional hiring and training are required. In addition, this PFD finds persuasive the Company's explanation that advertising expense, largely safety-related, was reduced due to reduced storm activity.

b. Preventative and Corrective Maintenance

Mr. Robinson testified in support of DTE's Preventative Maintenance O&M program. He explained that the program encompasses inspection, repair, and testing of selected substations and overhead and underground equipment to reduce outages, maximize the life expectancy of the equipment while maintaining safety and reliability, and acquire timely data to support trend analysis and identify potential issues.[1670] He asserted that the PM program cost-effectively enhances system performance and reliability.[1671]

Mr. Robinson testified that the program currently has been unable to meet scheduled inspection cycles resulting in maintenance backlogs. He stated that the maintenance backlog is comprised of preventative maintenance (PM), which are past due inspections and routine maintenance, and corrective maintenance (CM), which includes damaged or defective electrical or structural system equipment that needs to be repaired or replaced.[1672] He testified that DTE also needs to address inspection backlogs for

[1670] 4 Tr 1951-1955, Tables 6-8.
[1671] 4 Tr 1952-1953, 1955-1956.
[1672] 4 Tr 1956-1957.

padmount transformers, SCADA devices, and manholes, and conduct routine oil testing of power transformers as identified by the Liberty Audit.[1673]

Mr. Robinson presented the Company's plan to address the backlog as consisting of a two-pronged approach that will target completion of one-third of the backlog annually over the next three years and will increase inspections consistent with target maintenance cycles.[1674] He asserted that to implement the plan for the PM backlog and remain on target cycles, DTE requires an incremental $7.3 million in O&M for 2026.[1675]

Mr. Coppola testified that the Company's Exhibit A-13, Schedule C5.6, footnote 6 indicates that it added $7.3 million to the forecasted test year O&M expense for PM, and an additional $7.3 million for CM, for a total amount of $14.6 million.[1676] He testified further that in discovery DTE provided 2024 O&M expenses that provided those same amounts.[1677]

He asserted that DTE deferred undertaking CM in prior years, despite receiving increases in O&M expense recovery in those years, therefore the Company should correct the backlog at its own cost as customers should not have to pay twice for the work.[1678] He recommended a disallowance of the $7.3 million for CM expense for the projected test year.

As for the Company's request for another $7.3 million to address the PM backlog, Mr. Coppola noted that in discovery, the Company stated that approximately $5.0 million

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[1673] 4 Tr 1957-1958.
[1674] Tr 1958.
[1675] 4 Tr 1959; Exhibit A-13, C5.6, p. 1.
[1676] 4 Tr 3524.
[1677] 4 Tr 3524; Exhibit AG-40.
[1678] 4 Tr 3524-3525.

of the $7.3 million pertains to clearing the backlog and the remaining $2.3 million is to stay on cycle, and that there are no changes proposed to the current inspection cycles.[1679] According to Mr. Coppola, there should be no need for incremental expense in order to stay on cycle with preventive maintenance. He recommended that the Commission disallow the incremental expense of $7.3 million for PM, which along with his CM disallowance totals $14.6 million.[1680]

In rebuttal, Mr. Robinson countered that DTE is not seeking double recovery. He explained that Exhibit AG-40, referenced by Mr. Coppola shows that Preventative and Corrective Maintenance investments were included in the "Other Adjustment," column, which forms part of the "Projected Adjustments" for the "Projected Test Period." He maintained that this shows the work was not completed and if it had been completed it would have been reported in the column showing 2024 O&M actuals and would have been removed from the maintenance backlog.[1681] Mr. Robinson testified that Mr. Coppola's assertion that DTE has deferred CM in prior years despite receiving increased O&M expenses appears to be based only on the existence of the backlog. However, he maintained that the Company directly stated in discovery that the incremental CM line item "does not represent any actual historical O&M expenditures."[1682] Mr. Robinson asserted that DTE is not deferring CM, but incoming demands surpass the available investment. He added that CM activities come from electrical or structural system components that require extensive repair or replacement and are identified during

[1679] 4 Tr 3545; Exhibit AG-43.
[1680] 4 Tr 3545.
[1681] 4 Tr 2054; Exhibit AG-40.
[1682] 4 Tr 2054; Exhibit AG-43.

preventative maintenance inspections or customer outages. He testified that the data shows that despite ongoing work, the backlog continued to grow from 2021 to 2024.[1683]

As for the proposed disallowance for PM, Mr. Robinson maintained that Mr. Coppola misunderstood the Company's discovery responses related to its inspection cycles and that DTE was clarifying that the cycles reflect both current and historical inspection practices and are not newly proposed. He maintained that the Company's existing backlog has accumulated due to funding levels in the Company's rates that are insufficient to support the standard inspection and maintenance cycles along with corrective items found during customer outages and that is why the Company requested an incremental adjustment.[1684]

In briefing, DTE argues that it has not deferred maintenance and its requested funding for PM and CM is not redundant or duplicative, but incremental to its base plan and necessary to address O&M needs that have exceeded funding.[1685]

The Attorney General's brief incorporates Mr. Coppola's testimony and presents evidence gleaned in discovery showing that DTE had a backlog of 1,815 uncompleted CM items at the end of 2021, which increased to 2,738 by the end of 2023.[1686] She contends that DTE could not provide any information prior to 2021 to establish how the CM backlog came about or provide the amount of CM included in rates, but based on the 2020-2024 data the Company did provide, spending on CM has been erratic, ranging from $1.5 million in 2024 to $4.1 million in 2022.[1687] She argues that the evidence shows

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[1683] 4 Tr 2055; Figure 1.
[1684] 4 Tr 2056; Exhibit AG-43.
[1685] DTE brief, 163.
[1686] AG brief, 95-96.
[1687] AG brief, 96.

that the Company spent less than was approved in rates, continued to defer maintenance work, and now seeks higher maintenance costs to do work that should have been done in prior years with the available funding in rates.[1688] She argues that the same circumstances exist for PM, and that the Company again provided limited data, but that data shows that the number of PM items completed from 2021 to 2024, ranged from approximately 10,000 in 2021 to 33,000 in 2022, while the Company's spending ranged from $6.5 million in 2023 to $11.3 million in 2022.[1689] The Attorney General argues the DTE needs to show higher spending to resolve the CM and PM backlogs on its own before a higher O&M expense level should be considered in future rate cases and she reasserts her recommended disallowance of $14.6 million.[1690]

In reply, DTE argues that Mr. Coppola, does not convey a firm understanding of how the Company conducts the activities that are the subject of his recommendations. The Company contends that it "has presented operational and maintenance-based evidence that demonstrates an intention and desire to provide high quality electric service" and that the Attorney General's recommended disallowances would not help customers but "would exacerbate O&M demands and likely cause additional need in the future."[1691]

In her reply, the Attorney General continues to rely upon her initial brief and contends that DTE's briefing adds nothing new.

[1688] AG brief, 96.
[1689] AG brief, 97.
[1690] AG brief, 97-98.
[1691] DTE brief, 157.

This PFD finds that DTE submitted evidence to show that its proposed test year expenses for CM and PM totaling $14.6 million include incremental costs to correct backlogs that have been identified by the Company and by the Liberty Audit. This PFD agrees with the Company that the $14.6 million is not duplicative or redundant of prior years' O&M spending, which is supported by the existence of PM and CM backlogs. It is not clear how the backlogs occurred, whether as the Attorney General contends by the Company deferring the maintenance or as DTE contends by increased demands that surpassed available expenses. But this PFD finds it reasonable and prudent to address the backlogs. However, this PFD is concerned that the Company may have not spent enough in prior years to address the backlogs. Therefore, this PFD recommends that the Commission direct the Company to track its CM and PM activities and spending and in its next rate case report on the level of the backlogs still existing and how much was actually spent to reduce the backlogs. Based on the foregoing, this PFD rejects the Attorney General's $14.6 million disallowance for PM and CM in the Company's projected 2026 O&M expenses.

c. Tree Trimming

Ms. Steudle supported DTE's projected 2026 O&M expenses related to tree trimming, explaining that tree interference is one of the leading drivers of customer outages and that achieving the desired level of reliability of the Company's system requires that the Tree-Trimming program be sufficiently funded to maintain a tree-trim cycle that prevents vegetation interference before it becomes a hazard.[1692]

[1692] 4 Tr 2848-2849.

Ms. Steudle testified that in Case No. U-20162 in 2018, DTE proposed the Tree Trim Surge (the Surge) to obtain funding to trim all circuit miles to the Enhanced Tree Trimming Program (ETTP) specification by the end of 2025. The Company's proposal included a five-year cycle for distribution circuits (4.8kV, 8.3kV and 13.2 kV) and a three-year cycle for sub-transmission circuits (24kV and 40kV). She noted that the Commission has consistently approved regulatory asset treatment and O&M increases for the Surge.[1693]

She testified that in 2024, the Company trimmed or removed trees across 4,348 miles, bringing the system to 92% on-cycle. She explained that on-cycle means that "the trees associated with the circuit miles have been trimmed and/or removed to the ETTP specification at least once and are now on a regular maintenance cycle for future years." She defined "reclaim" miles as "miles that are not on-cycle" to include trees that have not been trimmed or removed since at least 2015.[1694]

Ms. Steudle presented the difference in outages, customer interruptions, minutes interrupted and wire-downs between the distribution circuits trimmed to the ETTP specification versus distribution circuits not trimmed to the ETTP specification through 2023.[1695] She noted that as the majority of circuits are now trimmed to the ETTP specification, the Company is implementing a new tracking methodology, which compares tree-related x-MED outages pre-trimming and post-trimming.[1696] She testified that the data so far shows that in the first year after trimming, circuits experience a 44%

[1693] 4 Tr 2850.
[1694] 4 Tr 2851.
[1695] 4 Tr 2854-2855, Table 1.
[1696] 4 Tr 2855-2856.

reduction in outages compared to the baseline, but the effectiveness reduces each subsequent year as the vegetation begins to regrow.[1697]

Ms. Steudle testified that DTE is on track to complete the Surge in 2025 and she noted that the Company overachieved its 2024 target by 345 miles, largely based on having necessary trimmers on hand and favorable weather conditions.[1698] She noted that in October 2024 in Case No. U-21799, the Commission approved DTE's request "to pull ahead" up to $15.6 million of the approved regulatory asset for 2025 into 2024. She explained, however, that the Company only spent $1.7 million of the pull ahead due to a very active 2024 hurricane season, but DTE anticipates spending the remaining $13.3 million of the pull-ahead regulatory asset in 2025. She stated that the tree trim budget for 2025 is $238 million and includes the $87 million incremental regulatory asset that was approved in Case No. U-21534. She testified that DTE has targeted 6,614 miles of tree trimming in 2025 of which 2,259 are the remaining reclaim miles necessary to complete the Surge.[1699]

Ms. Steudle testified that once the Surge is complete, the Company intends to transition to a risk-based prioritization model that uses remote sensing data, advanced analytics, and machine learning to estimate the probability of vegetation-driven failures to determine optimal trim cycles for each individual circuit.[1700] She maintained that "adjusting cycle lengths based on tree species' growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide improved reliability benefits to

[1697] 4 Tr 2856, Table 2.
[1698] 4 Tr 2857.
[1699] 4 Tr 2858.
[1700] 4 Tr 2859-2862.

customers."[1701] She explained that in Case No. U-20836 the Commission ordered DTE to explore the efficiency improvements and benefits of variable cycles. Additionally, she noted that the Liberty Audit also recognized the opportunity to explore risk-based cycles.[1702]

She indicated that while the Company is focused on finishing the Surge, it has started implementing the risk-based model and subsequently has deferred 2,000 on-cycle miles due for trimming in 2024 and plans to defer another 3,700 on-cycle miles from the 2025 plan. She stated that the purpose of the deferrals was to "begin learning and testing the model, and [to] repurpose more funding for the remaining reclaim miles that still need to be trimmed."[1703] She explained that the miles that were deferred in 2024 had a SAIFI of 0.15 while the overall system SAIFI was 0.18 and the 2023 SAIFI for the deferred units was 0.32, which demonstrates "no adverse impact in being deferred an additional year."[1704] She added that the Company is planning to defer over 50% more circuits in 2025 than 2024 and will closely evaluate performance of those circuits to ensure reliability is in line with the Company's system average, however, the Company is not anticipating pulling ahead or shortening the trimming cycle for any circuit in 2025.[1705]

She estimated that, when fully implemented to include both pull ahead and deferred miles, the average cycle length will be 5.8 years for distribution miles, or 5.6 miles if sub-transmission miles are included.[1706] She asserted that the Company is not

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[1701] 4 Tr 2859.
[1702] 4 Tr 2860.
[1703] 4 Tr 2862.
[1704] 4 Tr 2863.
[1705] 4 Tr 2863.
[1706] 4 Tr 2863-2864, Table 3.

concerned that over half of its circuit miles are expected to be on a trim cycle greater than the current five-year program because "[w]hile the majority of distribution miles will be greater than a five-year cycle," the data "illustrates that over two-thirds of DTE Electric's customers will remain on a five-year cycle or move to a four-year cycle."[1707] She stated that, "[b]eginning in 2026 the Company anticipates moving fully to risk-based cycles."[1708]

She testified that DTE performed a full review of its tree trimming program, which included a third-party assessment, peer benchmarking, a reconciliation of how the actual benefits of the Surge aligned to expectations, feedback and recommendations from prior rate cases, and the Liberty Audit.[1709] Based on the review, DTE is proposing three changes to its current tree-trim specifications. First, is the removal of species-specific overhang. Ms. Steudle explained that the current specification requires removal of overhang up to the first protective device and the Company proposes expanding the removal of overhang to include softwood species in Zones 2/3.[1710]

Second, the Company is proposing to improve the clearing of the floor, which she explained is the area directly under overhead equipment. She stated that removing brush and small trees that will eventually grow into the infrastructure ensures the Company has a well-defined, clear corridor along the overhead equipment and reduces the need to trim or remove trees in future tree trimming cycles.[1711] She also asserted that improving the

[1707] 4 Tr 2864, Table 3.
[1708] 4 Tr 2865.
[1709] 4 Tr 2865.
[1710] 4 Tr 2866, 2871-2872.
[1711] 4 Tr 2866.

floor is a common practice by other utilities to remove over 90% of the brush on their system, while currently DTE removes only 50%-60% of the brush it touches.[1712]

Lastly, Ms. Steudle testified that the third proposed change is to establish a dedicated program to address outside-the-right-of-way (OROW) trees that pose a risk of falling into the Company's overhead equipment.[1713] She explained that spending more on OROW trees would bring DTE investment in line with "best-in-class" vegetation management programs.[1714] She testified that at this time, DTE wants to maintain the current specification on the majority of the system and incorporate its three proposed changes on select circuits to collect data on costs and benefits.[1715]

Ms. Steudle testified that DTE is requesting $180 million of O&M funding for 2026.[1716] She explained that the funding includes $145 million for the Tree Trim Budget Base Plan which would cover the maintenance plan for approximately 6,000 miles of distribution and sub-transmission miles identified by the risk-based model along with supporting activities and functions and mid-cycle inspections and spot trimming. The funding requested also includes $35 million for the incremental costs associated with executing the three proposed specification changes.[1717]

Ms. Duell testified that Staff reviewed DTE's proposed tree trim expenditures and recommends that the Commission approve the spending of $180,000,000 for the projected test year.[1718] She noted that in DTE's last rate case the Commission approved

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[1712] 4 Tr 2872.
[1713] 4 Tr 2866.
[1714] 4 Tr 2872.
[1715] 4 Tr 2875.
[1716] 4 Tr 2875-2876; Exhibit A-13, Schedule C5.6.1.
[1717] 4 Tr 2875-2876.
[1718] 5 Tr 5261-5262.

spending of $109,000,000 in Base O&M and an additional $87,000,000 in incremental regulatory assets to complete the Surge program.[1719]

However, she testified that DTE's proposal to use risk-based cycle clearing after the completion of the Surge is problematic because the Company is proposing to clear 17% of their system on a 4-year cycle, 20% of their system on a 5-year cycle, 19% of their system on a 6-year cycle, and 36% of their system on a 7-year cycle.[1720] She noted that in its order in Case No. U-21305, the Commission stated that it does not want to lose the progress that has been made by achieving the five-year tree trimming cycle.[1721] Ms. Duell explained that based on this, Staff does not support the Company's proposal for risk-based cycle trimming and recommends that DTE continue on its second round of a 5-year trimming cycle.[1722] She also stated that Staff recommends that DTE complete an analysis of moving towards a 4-year tree trimming cycle as ordered in Case No. U-21305 to include the costs of, and a detailed explanation of, the advantages and disadvantages associated with a 4-year tree trimming cycle.[1723]

Ms. Duell further testified that Staff supports DTE's proposal to expand the removal of overhang to include softwood species in Zones 2/3 beyond the first protective device. However, she noted that Staff recommends that the Company provide a report within two years of the completion of this rate case on softwood overhang removal to include the following data: (1) how much softwood overhang was cleared each year since beginning the practice; (2) how much zone 1 overhang was removed over those same years; (3)

[1719] 5 Tr 5262.
[1720] 5 Tr 5262.
[1721] 5 Tr 5263; June 12, 2025 order in Case No. U-21305, p. 17.
[1722] 5 Tr 5263.
[1723] 5 Tr 5263-5264.

how many outages occurred due to overhang damage; and (4) the change in all-weather SAIDI and SAIFI due to softwood overhang removal.[1724]

Ms. Duell also commented that DTE did not provide testimony detailing its projected $94,979,000 O&M spending for storm restoration. She testified that Staff recommends that in future rate cases, DTE define and describe storm restoration and its expenses and provide a detailed explanation of the Company's storm restoration O&M expenses in the most recent three calendar years as well. Nonetheless, she testified that Staff reviewed and approves the projected test year service restoration spending of $94,979,000 in O&M expense but with any adjustments for inflation or normalization as recommended by Staff witness Rueckert.[1725]

Mr. Coppola recommended a reduction in DTE's tree trimming O&M expense. He testified that DTE provided information in discovery showing that its request for $145 million for the base program includes costs based on: (1) an average trimming cycle of 5.8 years; (2) a $10 million reserve for special tree trimming requests; and (3) $8.5 million for administrative costs.[1726] He added that the Company's request for $35 million for new programs consists of: (1) $6.2 million for overhang removal; (2) $10.3 million for increased tree/brush removal in the floor; (3) $15.1 million for OROW removal; and (4) $3.5 million for supporting costs.[1727] Mr. Coppola noted that there are no historical benchmarks to compare the expenditures to, and he opined that many of the estimated costs appear to

[1724] 5 Tr 5264.
[1725] 5 Tr 5265.
[1726] 4 Tr 3522; Exhibit AG-42.
[1727] 4 Tr 3523; Exhibit AG-42.

be rough order of magnitude estimates and sometimes duplicative of other costs already included in the base program.[1728]

Mr. Coppola opined that three items should be removed from the proposed $35 million specification change spending as they are excessive. First, he noted that the Company included $3.5 million for inspection and planning for the removal of OROW trees, but the base program already includes $8.5 million for program management costs. He stated that any new program planning should be done within the same staff group and the inspection and removal of OROW trees should occur in conjunction with ROW work, such that any additional costs should be the actual removal of trees and brush OROW.

Second, Mr. Coppola testified that the Company included $2.5 million for customer outreach and call center support without any explanation of the additional costs. He explained that DTE already notifies customers of tree trimming work being done in or around the customer's property, such that any incremental costs should be marginal.[1729] Third, he asserted that the Company included $2.322 million for additional trees to be removed without explaining why there would need to be funding for additional tree removal outside the base program, the $10 million reserve, and the OROW tree removal.[1730] He recommended that the Commission remove $8.322 million from the projected $35 million test year spending, reducing it to $26,716,000.[1731]

CUB/NRDC witness Bunch testified that while adaptive, or risk-based, tree trimming cycles are prudent, the Company's average trim cycle should not exceed the

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[1728] 4 Tr 3523.
[1729] 4 Tr 3523.
[1730] 4 Tr 3523-3524.
[1731] 4 Tr 3524.

recommendations of the Liberty Audit, approved by the Commission.[1732] Mr. Bunch cited excerpts from the Audit and noted that the Commission adopted the Liberty Audit recommendations in its order in Case No. U-21305, recommending DTE "stay on the five-year cycle while investigating the additional benefits of moving to a four-year cycle" and further "that the Company continue the current forestry methods and cycles, tuning and adjusting them as warranted by continuing evaluations of their costs and benefits."[1733]

Mr. Bunch testified that based on the foregoing, DTE is warranted to adjust its trimming cycles, but the preferred adjustment is a shortening of the cycles, while DTE is proposing cycles longer than five years for 55% of its circuit miles.[1734] Mr. Bunch recommended that DTE forgo its risk-based trimming cycle and maintain a five-year cycle for all circuits.[1735]

Dr. Stults expressed similar concerns about DTE's move to a risk-based tree-trimming program.[1736] She pointed out that the Company received funding to pay for trimming 5,700 miles that the Company is now proposing to defer.[1737] She stated:

> DTE is yet again beginning its habit of falling behind on tree trimming despite being funded at a level intended to maintain a 5-year cycle. If it follows its historical management practice, DTE will then argue in later rate cases that it needs additional resources to get these 5,700 miles back "on-cycle," ignoring its failure to trim the 5,700 miles in the prior two years and the funds received based on the assumption that work would be done.[1738]

[1732] 5 Tr 4844.
[1733] 5 Tr 4847-4848; June 12, 2025 order in Case No. U-21305, pp. 17, 21-22.
[1734] 5 Tr 4848.
[1735] 5 Tr 4849.
[1736] 4 Tr 3722-3723.
[1737] 4 Tr 3720-3721.
[1738] 4 Tr 3721.

She opined that DTE is using the risk-based model "as an excuse to fall behind its promised 5-year cycle on some circuits."[1739]

Dr. Stults recommended that if the Company continues to use the risk-based approach, it should not be able to recover any costs associated with tree-related outages on circuits that have not been trimmed in the five years prior to the outages because it is neither reasonable nor prudent to allow circuits to fall behind a five-year cycle.[1740] She also recommended that the Commission order DTE to track the costs associated with tree-related outages by circuit (or at least those in the group of circuits that were not trimmed in the last five years), with a statement it will in future years likely disallow recovery for any costs that are associated with tree-related outages on circuits that were last trimmed more than five years prior to the tree-related outages.[1741]

MNAG witnesses Alvarez and Stephens testified that DTE has fallen behind its Surge backlog. Mr. Alvarez testified that DTE's vegetation management illustrates that the Company is not going to increase O&M funding at the risk of losing profits, even to improve reliability.[1742] He stated that despite DTE's own admission that one-half to two-thirds of the time DTE customers spend without power results from vegetation contact, and despite hundreds of millions of dollars in securitized loans the Commission ordered to fund Surge spending, the data suggests that DTE is not only failing to catch up on vegetation management but is falling further behind.[1743] Mr. Stephens stated that "[T]he

[1739] 4 Tr 3722.
[1740] 4 Tr 3723-3724.
[1741] 4 Tr 3724.
[1742] 4 Tr 4605.
[1743] 4 Tr 4605-4606.

Company appears to have fallen further behind in 2023 and 2024, and appears likely to fall even further behind in the 2025-2028 period."[1744]

In rebuttal, Ms. Steudle stated that DTE disagrees with Mr. Coppola's assertion that its specification change proposals contain redundant spending. She elaborated on DTE's proposed spending for OROW inspection costs, which Mr. Coppola claimed includes $3.5 million in redundant spending. She explained that the incremental cost for inspecting and planning OROW trees is needed because the Company is significantly increasing the number of trees it will target and remove in 2026. She stated:

> The Company is doubling the distance outside the ROW that are identified as at-risk trees, incorporating these inspections into the midcycle inspections, and leveraging certified arborists to assess tree health and risk of failure. The Company projects to remove 200% more OROW trees compared to the base plan.
>
> The planning and inspection costs reflect the significant increase in time spent identifying these trees and then working with homeowners to gain permission to remove the trees.[1745]

She noted that DTE expects homeowners will have even greater hesitation and concerns over OROW trees being removed because these trees are outside the Company's easement and typically larger, established trees. She added that the time required to gain customer permission is included in the $3.5 million, and overall, the $3.5 million breaks down to about $250 per tree to inspect and then plan for removal.[1746] She testified that DTE is seeking $2.5 million for additional customer outreach because the Company expects that the increase in vegetation removal will lead to an increase in customer escalations, inquiries, and complaints, necessitating increased staffing in its call

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[1744] 4 Tr 4492-4493, Figure 4.
[1745] 4 Tr 2885.
[1746] 4 Tr 2886.

centers. She asserted that in addition to reactive management of customer concerns, the Company is identifying ways to increase its education and proactive communication to customers around the tree trimming program and the additional requested funding will go towards supporting these efforts.[1747]

As for the $2.3 million for additional tree removal that Mr. Coppola suggests is redundant, Ms. Steudle referred to it as “small tree removal” and stated it is necessary to remove about 175,000 trees per year. She testified that the $2.3 million reflects the incremental cost to remove those trees compared to trimming them again, while the cost in the base plan reflects trimming these trees as opposed to removing them.[1748]

Ms. Steudle testified that DTE is supportive of Ms. Duell’s recommendation to conduct a study with respect to the removal of softwood overhang, however, the Company would like to collaborate with Staff to refine the proposed study. Specifically, she stated, the Company feels it is important to use a holistic approach and evaluate the costs and benefits of all three proposed specification changes.[1749]

As for MNAG witnesses Alvarez’s and Stephens’ assertions that DTE has fallen behind in its Surge trimming, Ms. Steudle disagreed. She suggested that Mr. Stephens’ presentation of "Vegetation Management miles completed by year relative to the amount required to achieve a 5-year cycle,” shown as Figure 4 in his direct testimony is inaccurate. She explained that it portrays the annual requirement of distribution miles the Company must trim each year to remain on a fixed 5-year cycle at approximately 6,500, while the figure should instead have shown 5,700 miles as the annual requirement. She

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[1747] 4 Tr 2886.
[1748] 4 Tr 2886-2887.
[1749] 4 Tr 2887.

noted that the actual miles the Company has trimmed/plans to trim for 2025 and onward is also not accurate. Therefore, she asserted that the conclusions drawn by Mr. Stephens and Mr. Alvarez that rely on Figure 4 are incorrect and should be disregarded.[1750] Further she added that both witnesses appear to be conflating the maintenance of a strict, 5-year trimming cycle, or lack thereof, with the creation of a backlog. She suggested that this is inaccurate and that the Company has consistently referred to the backlog as the portion of miles not yet trimmed to the ETTP specification.[1751]

Ms. Steudle opined that many of the intervenors objections to risk-based cycling appear to be based on perceived inconsistencies with the Liberty Audit and the Commission's order in Case No. U-21305.[1752] She highlighted the "Trim Miles and Costs," "Conclusions," and "Recommendations" sections of the Liberty Audit and maintained that DTE is following the recommendations and is committed to maintaining a tree trimming program that aligns with the audit, the Commission's U-21305 order, as well as the Commission's order in Case No. U-20836. She maintained that by completing the Surge, the Company will have no remaining off-cycle miles and no backlog with respect to tree trimming.[1753]

She observed that the risk-based program is not "an excuse to fall behind" as noted by Dr. Stults, rather it enables the Company to do exactly what she and other intervenors desire, shorten the cycle length for some circuits. She noted that almost 40% of DTE's customers reside on circuits that will move to an accelerated 4-year cycle under the

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[1750] 4 Tr 2888.
[1751] 4 Tr 2889.
[1752] 4 Tr 2889-2890.
[1753] 4 Tr 2891-2893.

Company's proposal and that over two-thirds of customers will be on circuits with a 4 or 5-year trim cycle.[1754] She explained that the Liberty Audit did not provide an endorsement of 4- or 5-year tree trimming cycle as an end point, as Ms. Stults suggested, but as a step toward a more mature and refined tree trim program, which is DTE's intended outcome in utilizing its risk-based approach. She opined that, "[T]argeting circuits based on their unique risk profiles that allow for longer trim cycles is a feature of the model, not a flaw."[1755] She stated that DTE has matured in its vegetation management, from recognizing it was off-cycle, to using the ETTP specification and beginning the reclamation process, and then to the Surge. She opined that the "next logical step" is to strategically employ technology to trim efficiently and cost effectively, or "trimming the right miles at the right time."[1756]

Ms. Steudle testified that the incremental cost in moving from a 5.8-year average risk-based trim cycle to a fixed 5-year trim cycle was estimated to be $20 million more than the Company's current $180 million request for 2026. She asserted that DTE believes that its specification changes are a more prudent investment than incremental funding to maintain a fixed 4- or 5-year cycle.[1757]

Ms. Steudle concluded her rebuttal testimony by countering the intervenors' implications that DTE's proposed 2026 budget neglects tree trimming and falls back on the progress gained by the Surge. She stated while the risk-based approach will cost relatively less than a 5-year cycle, the Company is proposing to maintain a significantly

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[1754] 4 Tr 2892.
[1755] 4 Tr 2894.
[1756] 4 Tr 2895.
[1757] 4 Tr 2896-2897.

higher base budget than has ever been historically forecasted for post-Surge and the Company's requested funding for 2026 is in line with investment levels during the Surge, and over 170% greater than pre-Surge (2014-2018) investments.[1758] She recommended that the Commission approve the Company's requested $180 million including its expanded specification initiative of $35 million; disregard Mr. Coppola's assertions that $8.3 million is duplicative; and fully support the Company's risk-based approach to tree trimming.[1759]

Mr. Kryscynski provided rebuttal testimony in response to Ms. Duell's recommendations on storm restoration O&M expenses. He testified that DTE agrees to provide additional support and explanation for storm restoration O&M expenses in future rate cases. However, he noted that the Company provided additional information on this spending in discovery.[1760]

In briefing, DTE largely relies on Ms. Steudle's testimony. The Company emphasizes that any attempt to use the U-21305 order to prevent moving to a risk-based cycle ignores the Commission's directive to explore cycle optimization and that its proposal is an evidence-based progression that enhances reliability, controls cost, and aligns with regulatory and industry guidance.[1761]

In its brief, Staff states that it reviewed DTE's rebuttal testimony and other parties' testimony and maintains its position that the Company should not move towards a risk-based cycle approach and instead should continue onto its second round of a five-year

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[1758] 4 Tr 2900, Figure 1.
[1759] 4 Tr 2900-2901.
[1760] 3 Tr 1250.
[1761] DTE brief, 167-168.

cycle.[1762] Staff also recommends that a report regarding tree trimming be filed within two years of the Commission's final order in this rate case and Staff agrees to work with DTE on the expected contents of the report. Staff recommends the Company provide the costs associated with moving towards an effective 4-year tree trimming cycle and explain in detail the advantages and disadvantages of moving towards a 4-year tree trimming cycle.[1763]

In her brief, the Attorney General reiterates Mr. Coppola's testimony and argues that DTE's discovery responses confirm his opinion that some of the costs proposed by the Company for its specification change program are duplicative because the activities will be completed at the same time that routine tree trimming will take place.[1764] She notes for instance that DTE could not explain how it concluded that its proposed OROW work would remove 200% more trees.[1765] The Attorney General argues that DTE has not provided support for the full $35 million incremental spending for the specification changes and she reiterates that $8.322 should be removed.[1766]

In its brief, MNSC generally reiterates its witness's and other intervenors' testimony and argues that DTE has still not reached a point where all its distribution circuits are on a 5-year tree trimming schedule and if the Company's risk-based proposal is approved, it is unlikely it ever will. The MNSC recommend that the Commission hold firm to a five-year

[1762] Staff brief, 216.
[1763] Staff brief, 217.
[1764] Attorney General brief, 92.
[1765] Attorney General brief, 92-93.
[1766] Attorney General brief, 93-94.

tree trimming cycle as promised and paid for by the Surge and reject DTE's attempt to lengthen trimming cycles, potentially jeopardizing ratepayer-funded reliability gains.[1767]

In its brief, Ann Arbor reiterates Dr. Stults' testimony and recommendations and argues that the onus of willfully failing to maintain the minimum recommended tree trimming cycle should be on the Company rather than on ratepayers who have already paid for the Company to play catch up.[1768]

DTE replies that if it is required to trim on a strict five-year cycle, it will need at least $20 million more than its current $180 million request for 2026 to trim the requisite 6,544 miles.[1769] Alternatively, DTE states that it is open to collaborating with Staff to best optimize its approved funding in terms of specification miles trimmed and specification changes for the test year and recommends that the collaboration occur by the end of Q1 2026. Accordingly, the Company requests that the Commission refrain from ordering the Company to complete a 4-year trimming cycle analysis, as recommended by Staff, until after the Company and Staff are able to define the parameters of a forthcoming report on the tree-trimming program.[1770]

The Attorney General replies that DTE's support for its Specification Change Project consisting of $35 million of additional funding over the base tree-trimming program is based on vague and unhelpful claims and she asserts that "it is frustrating that DTE seemingly cannot commit to, focus on, and execute one vegetation management plan, before it comes up with something new and more expensive to pitch to the

[1767] MNSC brief, 157.
[1768] Ann Arbor brief, 6.
[1769] DTE reply, 159.
[1770] DTE reply, 160.

Commission."[1771] However, she clarifies that she is very supportive of vegetation management practices as one of the best ways to improve reliability on a per dollar basis, but in this case DTE has failed to adequately justify the need for $8.322 million for its Specification Change project.[1772]

In their replies, both MNSC and the City of Ann Arbor refute DTE's assertions that its risk-based cycle follows Commission orders and the Liberty audit. They argue that while Liberty does recommend examining trim cycles, it specifically recommended this in the context of examining shortened trim cycles.[1773] MNSC further argues that it is not opposed to variable trim cycles per se, but it is opposed to DTE's risk-based proposal, which would slow trim cycles across 55% of circuits.[1774] Ann Arbor further replies to DTE's argument that it is not planning to fall behind the five year cycle because 70% of customers will remain on a 4- or 5-year cycle. According to the City, the other 30% will be on circuits that are on 6- or 7-year cycles, and thus, DTE's proposed variable tree trimming cycle is indeed a plan to intentionally lengthen the average tree trimming cycle.[1775] Ann Arbor also contends that after spending $500 million of ratepayer money on the Surge to rectify a backlog caused by years of underinvestment that it would be imprudent and unreasonable not to spend $20 million to maintain it.[1776] The City posits that DTE appears partial to costly capital investments over proper preventive maintenance, "which is what led to the need for the Surge in the first place and results in

[1771] Attorney General reply, 49.
[1772] Attorney General reply, 49.
[1773] MNSC reply, 6-7; Ann Arbor reply, 1-2.
[1774] MNSC reply, 7.
[1775] Ann Arbor reply, 2.
[1776] Ann Arbor reply, 3.

doubly burdening ratepayers – first, they pay the cost of the capital investments (plus the rate of return), and then they pay for emergent spending that arises as a consequence of skimping on maintenance."[1777]

This PFD notes that the order in Case No. U-21305 was issued on June 12, 2025, after DTE filed this rate case. The order is not ambiguous. The Commission stated that, "[a]t a minimum, the Commission does not want to lose the progress that has been made by achieving the five-year tree trimming cycle. The Commission recommends that the company stay on the five-year cycle while investigating the additional benefits of moving to a four-year cycle."[1778] This PFD generally agrees with Staff, MNSC, and Ann Arbor that the Commission wants DTE to stay on the five-year cycle and investigate shortening the cycle and not move to longer cycle lengths for any trees. This PFD finds it concerning that DTE has already deferred the trimming of thousands of on-cycle miles and plans to defer thousands more. This is not consistent with the Commission's Order. Therefore, this PFD finds that DTE's proposal to move to risk-based cycling is contrary to the Commission's directives and unreasonable.

Consistent with the above, this PFD recommends that the Commission direct DTE to discontinue risk-based tree-trimming and proceed with a consistent five-year trimming cycle for all trees. Further, in accordance with Staff's recommendation, DTE should investigate the costs and benefits of moving to a 4-year cycle, explaining in detail its advantages and disadvantages, and provide a report to the Commission on its findings.

[1777] Ann Arbor reply, 3-4.
[1778] June 12, 2025 order in Case No. U-21305, p. 17.

In this report, the Company, may if it chooses to, make a comprehensive case supporting risk-based cycling for the Commission's review and consideration.

As for DTE's proposed specification changes, this PFD finds that they are in line with the Commission's U-21305 Order. In the order, the Commission found that DTE "should analyze the incremental costs and benefits of expanding trimming zones and of clearing underbrush and hazard trees" and "should explore the incremental benefits related to expanding overhang removal in all tree trimming zones and clearing underbrush."[1779] Therefore, this PFD recommends approval of DTE's three proposed specification changes. Further this PFD agrees with Staff's recommendation, as agreed to by DTE, that the Company provide a report within two years of the completion of this rate case on the implementation and results of the three proposed specification changes, with the specific contents of the report to be determined by DTE and Staff.

Turning to the Attorney General's recommended removal of $8.322 million from the Company's proposed $35 million specification change expenditures for the test year, this PFD agrees with the Attorney General that DTE failed to adequately support $3.5 million for the inspection and planning for OROW tree removal, $2.5 million for customer outreach and call center support, and $2.322 million for additional trees to be removed. This PFD agrees with her that the incremental costs for inspections and planning for OROW tree removal and customer outreach and call center support should be marginal and that the removal of 175,000 trees beyond those already included in the base plan and the OROW removal should not be needed. Therefore, this PFD recommends that the

[1779] June 12, 2025 order in Case No. U-21305, pp. 17, 22-23.

Commission remove $8.322 from DTE's proposed test year O&M tree trimming expenses.

d. Staking and Locating

Mr. Hill testified that DTE's MISS DIG/Damage Prevention costs have increased. Citing Exhibit A-13, Schedule C5.6, page 4, he indicated that Miss Dig 811 membership fees have increased "for $0.1 million," and that contractor staking has increased "for $2.9 million," because two competitively bid staking contracts, market conditions, staking volume, and unit staking costs have all increased.[1780] The exhibit indicates $497,000 for MISS DIG fees in 2023; a 2024 inflation adjustment of $17,000; a $15,000 inflation adjustment for 2025; an inflation adjustment of $16,000 for 2026; and "other adjustments" of $59,000, for a projected test period MISS DIG expense of $605,000.[1781] For contractor staking, actual costs were $6,877,000 for 2023; DTE's proposed inflation adjustment for 2024 was $234,000; for 2025 it was $213,000; for 2026 it was $227,000; and "other adjustments" are $2,941,000, for total projected contractor staking expenses for the test period of $10,492,000.[1782]

Mr. Coppola stated that, generally, he used inflation factors of 2.8% for 2025 and 2.4% for 2026 based on the Consumer Price Index-Urban forecast from June 2025 where inflationary cost pressure was a factor.[1783] More specifically, however, Mr. Coppola took issue with DTE's proposed $2.9 million increase in staking and locating expense over 2023, starting with the position that inflationary cost increases should not be added to

[1780] 4 Tr 2796.
[1781] Exhibit A-13, Schedule C5.6, p. 4.
[1782] Exhibit A-13, Schedule C5.6, page 4.
[1783] 4 Tr 3427.

contractor cost increases because the increase is already reflected in prices.[1784] He opined that this duplication was "worth about $675,000."[1785] Mr. Coppola next took the position that the forecast of 38,468 additional staking and locating requests from 2023 through 2026 was "exorbitant and unsupported."[1786] He expressed apparent frustration that the Attorney General's discovery requests to DTE for contractor bid prices and related information were rebuffed, that the video conference review DTE offered of requested information was inadequate, and that the "few highly redacted documents" that were provided before the intervenor testimony deadline came with "insufficient time to analyze."[1787]

Referencing Confidential Exhibit AG-44, Mr. Coppola stated that DTE indicated that the $2.9 million increase in staking and locating included $1,618,000 of "incremental adjustments" for 2026, and he maintained the increase was "grossly inflated, partially unsupported, and unverifiable."[1788] Mr. Coppola noted that MISS DIG fees had been doubled from the $605,000 in 2024 to $1,285,000 in 2026, plus an added $975,000 in unexplained contractor staking costs. He stated that he adjusted the base distribution O&M expense based on the increase in expense from 2024 to 2026 to recommend removal of $1,618,000.[1789]

In rebuttal, Mr. Hill contested the notion that $675,000 of the inflation increases were duplicative of increased prices, instead countering that the reduction should be

[1784] 4 Tr 3526-3527.
[1785] 4 Tr 3526.
[1786] 4 Tr 3526.
[1787] 4 Tr 3527.
[1788] 4 Tr 3527.
[1789] 4 Tr 3527.

rejected because Mr. Coppola's calculation was not provided and was thus unsupported.[1790] Mr. Hill similarly rejected Mr. Coppola's contention that forecasted staking volumes are overstated, indicating that DTE had 2.2% increase in staking and locating requests from 2023 to 2024, and this was the basis for DTE's forecasted 2.4% increase for 2025 and 3.2% increase for 2026. Mr. Hill stated that electric staking through August 2025 was "on pace to set a historic record for ticket volume."[1791] He stressed that DTE contracts all staking and locating services, and that the contracts were the result of a competitive RFP bidding process reflecting current labor and materials market prices. Mr. Hill maintained that Mr. Coppola had not supported his assertion that the 41% increase in contractor costs between 2023 and 2026 was exorbitant, and he further maintained that Mr. Coppola's recommendations should be rejected as unsupported.[1792]

The Attorney General maintains that adding inflationary cost to contractor cost increases is inappropriate because the increased contractor costs already address inflation, explaining that the $675,000 duplication of expenses is the addition of the 2024, 2025, and 2026 inflation adjustments from Exhibit AG-44, page 4.[1793] The Attorney General's brief asserts that the projected increase in higher volumes of staking and locating requests are not supported by historical rates of volume growth and that "no quantifiable evidence has been presented to justify the higher growth rates."[1794] She further asserts that her discovery request to DTE, AGDE-13.365, provides data establishing that DTE's claimed 41% increase in contractor costs is exorbitant. As a

[1790] 4 Tr 2829-2830.
[1791] 4 Tr 2830.
[1792] 4 Tr 2831.
[1793] Attorney General brief, 98-99.
[1794] Attorney General brief, 99.

result, the Attorney General recommends removal of the $1,618,000 special expense increase, recommending instead allowance of $2.9 million based on Mr. Coppola's adjustment of base distribution O&M for 2024 to 2026.[1795]

DTE responds only briefly to this, contending generally that the Company's O&M requests are not redundant or duplicative, and that, in relation to staking and locating specifically, the funding request is based on documented operational requirements. Therefore Mr. Coppola's proposed disallowance should be rejected.[1796] In its reply brief, the Company includes staking and locating in its general response to the Attorney General's recommended disallowances for distribution O&M expenses, contending that the "recommendations are not grounded in the practical conduct of the Company's O&M activities."[1797] that disallowances now will only "exacerbate O&M demands and likely cause additional need in the future," and that the expenditures are fully supported in the Company's initial brief and initial and rebuttal testimony.[1798] The Attorney General relies on her initial brief as her reply.[1799]

Both parties make valid points. DTE appears to be correct that staking volumes have increased, as have contractor costs and MISS DIG fees. The Attorney General is correct that adding inflation onto contracted expenses also appears incorrect. This PFD recommends disallowance of inflation for this category.

e. Distribution "Surge" and Stranded Costs

[1795] Attorney General brief, 99.
[1796] DTE brief, 163.
[1797] DTE reply, 156.
[1798] DTE reply, 156-157.
[1799] Attorney General reply, 47-48.

MNSC and the CEO, with support by the Attorney General, request that the Commission direct DTE to record capital and O&M costs related to "catching up" on deferred maintenance and capital investments (PTMM) to be recorded as a regulatory asset for eventual securitization.[1800] In addition, MNSC recommends that the Commission direct the Company to remove from rate base the net book value of assets taken out of service as part of DTE's system conversion program. The remaining value of these assets, as well, should be recorded as a regulatory asset for eventual securitization.[1801]

While these recommendations are well-presented, and the distribution "surge" proposal seems analogous to the previously approved tree-trimming surge, this PFD is not convinced that the Company's apparent underspend on O&M was the result of imprudence or some intention on DTE's part to avoid inspections and maintenance in order to overspend on capital investments. In addition, MNSC's concerns about capitalization of certain PTMM activities (addressed above and recommended for inclusion and consideration in DTE's next depreciation case) could affect the regulatory asset for PTMM, if approved.

As for the proposal to approve a regulatory asset for stranded distribution assets, the record is unclear as to the details of how this might be accomplished, and whether this as well might be addressed in the Company's upcoming depreciation case.

7. Lighting Expense

Mr. Hartly testified regarding Community Lighting O&M expense, which includes preventative maintenance (including post inspection, post painting, and night patrols),

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[1800] MNSC brief, 6.
[1801] MNSC brief, 5-6; 48-53; 201-204; CEO brief, 29-32.

labor, and non-capitalized outage restoration O&M, as shown in Exhibit A-13, Schedule C5.6.[1802] DTE projects Lighting O&M expense of $4.6 million for the test year. Disputes concerning Community Lighting programs and O&M expense were largely raised by MAUI/PROTEC, and are addressed below.

a. Community Lighting Replacement

According to Mr. Hartly, current lighting charges include a monthly energy charge, capacity charges and a luminaire charge. Mr. Hartley explained that the luminaire charge "is a fixed monthly amount applied to each luminaire dependent on the technology utilized, the lamp size or wattage, the lighting provision and whether it is served from underground or overhead."[1803] He added that there are four lighting types currently in use within DTE's service territory: Light Emitting Diode (LED), High Pressure Sodium (HPS), Metal Halide (MH), and Mercury Vapor (MV).[1804] The spectrum runs from LED as the most efficient lighting type available to MV, which became obsolete and was banned from production in the United States in 2008.[1805] Mr. Hartley testified that DTE set the recommended monthly luminaire energy charge by applying the energy rates to the "calculated consumption values of the various lighting technology lamp sizes for both the E1 and D9 Rate Schedules."[1806]

Mr. Hartley explained that DTE's current lighting rates were established in a manner meant to transition toward cost-of-service rates, with caps to minimize impact on

[1802] 3 Tr 1429.
[1803] 3 Tr 1433
[1804] 3 Tr 1411-1412
[1805] 3 Tr 1412
[1806] 3 Tr 1433

any individual municipal customer.[1807] The transition to cost of service has been in process since the Commission issued its January 31, 2017, order in Case No. U-18014. In that case, conversion of MV lighting to LED lighting was at issue and DTE represented that it had a total population of 52,000 MV luminaires and a plan to convert them to LED luminaires at a rate of approximately 11,000 in 2014, approximately 12,000 in 2015, and was in the process of developing its conversion numbers for 2016.[1808] Thus, the Company was converting at a rate of a little over 20% of its total MV luminaires each year with a 5-year trajectory for completion. The Company did not complete the conversions in that 5-year period, and, in this case, the Company proposed extending that transition from less efficient luminaires, including its remaining MV luminaires, an additional seven years.[1809]

The Company set the proposed luminaire cost structure in the proposed tariff schedule "by reviewing and allocating the specific cost-of-service components to the type of service, underground or overhead, and then further allocating them to the individual lighting technologies."[1810] This process limits the overall increase to 2.45 times the proposed average increase in revenue requirement and then allocates the remaining revenue deficiency, on a percentage basis, to all remaining lights.[1811] The Company uses the same process for both the E1 Option I and the D9 Rate Schedules.[1812]

[1807] 3 Tr 1433
[1808] 4 Tr 1162
[1809] U-18014, 3 Tr 1446-8. DTE's plan for MV luminary conversion in 2017 was for replacement of all MV luminaires, but DTE witness Hartley's testimony indicates that DTE has been converting only "failed" MV lighting, which is not consistent with the testimony provided in 2017.
[1810] 3 Tr 1434
[1811] 3 Tr 1439
[1812] 3 Tr 1440

MAUI/PROTEC witness Schultz testified that the current and proposed rate structure results in streetlights served by underground (UG) wires paying more than cost of service and streetlights served by overhead (OH) wires paying less than cost of service creating a "de facto cross-subsidization of OH lights at the expense of UG lights."[1813] Mr. Schultz testified that on a per-light basis OH MV and MH received "at least twice the amount of subsidization as HPS luminaires," with OH MV receiving "the largest aggregated subsidization."[1814]

In light of his conclusion, Mr. Schultz, proposed the accelerated conversion of OH MV luminaires and recommended the Company "begin converting all remaining MV fixtures with their equivalent LED luminaire, even if those MV fixtures have not yet failed."[1815] Mr. Schultz further testified that his proposal targets MV luminaires because they "have been fully depreciated and their costs fully recovered," MV luminaires receive a greater subsidy, and the Company has been "making good progress in converting HPS luminaires."[1816] Further, based on his assertion that MV fixtures are fully depreciated, that the Company is waiting for fixture failure, and that the Company has previously recognized economic efficiencies gained from planned conversions versus reactive conversions, Mr. Schultz suggests that the Company should not charge Contribution in Aid of Construction (CIAC) for the conversion to LED.[1817] Mr. Schultz opined that this

[1813] 4 Tr 3746
[1814] 4 Tr 3748
[1815] 4 Tr 3750
[1816] 4 Tr 3751
[1817] 4 Tr 3751-2. Referencing testimony from Company witness Johnston in Case No. U-18014 (2016). In 2016 when Mr. Johnston testified, there were approximately 52,000 MV luminaires and the Company was converting them at a rate of 11,000-12,000/year. MPSC Case No. U-18014, 4 Tr 1162.

proposal would speed up the transition to cost of service rates and would be more fair to municipalities that have already converted to LED luminaires.[1818]

In rebuttal, Mr. Hartley characterized Mr. Schultz's proposal as financially imprudent and – contrary to Mr. Schultz' claim that proactive replacement would reduce cost to customers – would result in unnecessary cost burdens for customers.[1819] Mr. Hartley testified that DTE's proposed plan is consistent with Commission-approved policy to replace MV fixtures upon failure and the proactive replacement recommended by MAUI/PROTEC would accelerate cost recovery and increase lighting rates.[1820] Additionally, adopting a proactive replacement policy would impose an unfunded capital cost estimated somewhere between $1.7 million and $2.5 million that would be recovered through rates, which would increase costs for all lighting customers.[1821] In response to Mr. Schultz' assertion that the MV luminaires are fully depreciated, the Company states that it is impossible to determine how many of the remaining operational MV fixtures are fully depreciated. The Company also noted that the current replacement policy avoids CIAC for MV conversions because the costs are recovered through rates.[1822] The Company's current rate proposal will result in replacement of remaining MV fixtures within seven years, though it is willing to commit to an accelerated timeline of five years.[1823]

In its brief, DTE reiterates the rebuttal testimony of Mr. Hartley opposing proactive conversion of all MV fixtures to LED under the E1 tariff and asserts the Commission

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[1818] 4 Tr 3750
[1819] 3 Tr 1446
[1820] 3 Tr 1444
[1821] 3 Tr 1446
[1822] 3 Tr 1447
[1823] 3 Tr 1447-1448

should deny any mandate requiring the Company to proactively convert the remaining MV streetlight fixtures.[1824] The Company is prepared to accelerate this timeline to five years, balancing cost effectiveness with the objective of modernizing the lighting infrastructure, but opposes proactive replacement of all MV fixtures because it would require $1.7 to $2.5 million in unfunded capital costs, leading to higher rates for lighting customers.[1825]

In its brief, MAUI/PROTEC state that allowing DTE to continue its gradual move from MV streetlight luminaires to LEDs would perpetuate the cross-subsidization and inequities that have existed for at least a decade. Instead, MAUI/PROTEC assert that the Commission should require DTE to proactively convert its streetlights from mercury vapor to LED and find that CIAC is unnecessary.[1826] MAUI/PROTEC then reiterate the history of DTE's move to cost of service pricing.[1827]

MAUI/PROTEC argue that directed conversion would have multiple benefits. First, it would end cross-subsidization and bring rates closer to cost of service. Second, customers who convert from MV to LED would see cost savings. Third, proactive conversion would prioritize energy efficiency and help meet state climate goals.[1828] Finally, MI-MAUI contends that requiring a CIAC for proactive conversion from MV to LED fixtures would be inappropriate because the MV fixtures are beyond their assumed useful life and it avoids more expensive reactive replacements.[1829]

[1824] DTE brief, 240-1
[1825] DTE brief, 241
[1826] MAUI brief, 9
[1827] MAUI brief, 10
[1828] MAUI brief, 11-12
[1829] MAUI brief, 13-14

Both Mr. Schultz and the Company refer to Case U-18014 to justify their testimony regarding the transition to cost of service rates for community lighting. In 2017, DTE stated that "the luminaire-related depreciation expense was allocated based upon a useful life of . . . 10 years for mercury vapor . . . technologies . . . [which] addresses DTE Electric's expectations regarding the obsolescence of . . . these technologies and expectations that it could replace its entire portfolio of mercury vapor streetlights within the next 5 to 10 years[.]"[1830]

When the Commission issued its order in U-18014, DTE projected that all remaining MV luminaires could be converted within five years.[1831] As of September 2025, there are approximately 7,100 MV luminaires remaining in service[1832] and the Company avers that it should be allowed to continue its gradual transition to cost of service rates for another 5 to 7 years.

This PFD finds MAUI/PROTEC's arguments to be persuasive. MCL 460.11(1) provides, "the Commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid." In reviewing the history of this issue in Case U-18014, it appears that the Company should have already achieved total replacement of its MV luminaires or that total replacement of MV luminaires should be imminent. Neither the record for this case, nor the previous case contain any discussion of why the Company still has MV luminaires in service when it expected them to be replaced by 2022. Further, while the Company represents that the Commission has a policy favoring replacement of MV units only upon failure, there is nothing in this record demonstrating such a policy was

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[1830] U-18014, 4 Tr 1162 KDJ 26
[1831] U-18014, KDJ 19-20
[1832] 3 Tr 1446

officially stated by the Commission in past cases. Instead, the record in this matter demonstrates that the retirement of MV luminaires will have a significant impact on energy usage, decrease the revenue deficiency currently allocated across other lights as a de facto subsidy, and move the Company closer to cost-of-service rates for lighting. Therefore, to ensure that the cost for this rate class is fair and equitable, this PFD recommends that the Company be required to submit a cost benefit analysis for completing MV replacement not later than 2028 in its next rate case, as well as a similar analysis for remaining MH and HPS replacement.

b. Pole Inspection and Painting

Mr. Hartley testified that DTE owns a combination of approximately 60,000 decorative metal or fiberglass posts and maintains an inspection program that operates on a three-year cycle. The program inspects approximately 20,000 posts per year conducting minor maintenance or replacement, as needed.[1833] The Company replaces approximately 3% and paints approximately 2% of posts relative to the total population of posts.[1834] DTE included approximately $165,000 for post inspections and approximately $250,000 for post painting.[1835] The account representing preventative maintenance does not break out amounts for post inspection or post painting, but shows $3.4 million for the historical period and $4.6 million in the projected test period with inflation rates of 3.4% for 2024, 3.0% for 2025, and 3.1% for 2026.[1836]

[1833] 3 Tr 1419
[1834] 3 Tr 1420
[1835] 3 Tr 1420
[1836] 3 Tr 1429-30; Exhibit A-13, Schedule C5.6, page 1, line 23.

Mr. Schultz expressed concern regarding the requested recovery for streetlight inspection and painting vis-à-vis historical actual expenditures, as well as consistency across the Company's testimony.[1837] Mr. Schultz explained that DTE spent $124,349 on streetlight inspections and $200,121 on streetlight painting to inspect 23,194 streetlights and paint 899 streetlights in 2024.[1838] The Company owns more than 60,000 streetlights and the inspection program is on a three-year cycle, which would correspond to the annual inspection of approximately 20,000 streetlights, and Mr. Schultz acknowledged that the Company met its goal.[1839] Mr. Schultz stated that because the Company was successful in meeting its inspection and painting goals in 2024 with the above expenditures, the values from 2024 serve as an adequate baseline cost for the program. Consequently, applying the Company's labor inflation rates to the Company's declared allocations, MAUI/PROTEC recommends disallowing $70,700 from the Company's preventative maintenance program.[1840]

In rebuttal, Mr. Hartley disputed the recommended disallowance from the preventative maintenance budget, on the basis that it "relies on a narrow inflation-based projection and fails to account for operational realities such as backlog reduction efforts, material cost volatility, and contractor availability.[1841] Mr. Hartley testified that material costs for paint and related supplies could increase by as much as 15%, thus the proposed

[1837] 4 Tr 3755
[1838] 4 Tr 3755
[1839] 4 Tr 3756; 3 Tr 1419
[1840] 4 Tr 3757
[1841] 3 Tr 1444-1445

reduction would limit proactive maintenance, increase reliance on more costly and less efficient reactive repairs, which would in turn elevate safety and reliability risks.[1842]

In its brief, DTE reiterates Mr. Hartley's testimony, reasserting that the Commission should reject the proposed disallowance of $70,770 recommended by MAUI/PROTEC.[1843] The Company repeats that the disallowance relies on a narrow inflation-based projection and fails to account for operational realities such as backlog reduction efforts, material cost volatility, and contractor availability. The Company further asserts that the proposed disallowance also fails to consider operational needs, such as staffing, as well as overall cost variability. Thus, reducing funding would similarly reduce benefit to the customers by limiting proactive maintenance, increasing reliance on reactive repairs, and elevating safety and reliability risks.[1844]

In its brief, MAUI/PROTEC rely on Mr. Schultz's testimony regarding the expenses of the 2024 inspection and painting programs and DTE's projected labor inflation rates for 2025 and 2026.[1845] While MAUI/PROTEC recognize the importance of the programs and generally support them; their brief articulates concern that the requested amounts outpace DTE's inflationary rates and therefore DTE's request for $165,000 for Post Inspection and $250,000 for Post Painting is not just and reasonable.[1846] MAUI/PROTEC further assert that rebuttal testimony offered by DTE was an attempt to supplement the Company's direct case rather than contradict, explain, or disprove evidence produced by

[1842] 3 Tr 1445, 1449-1450.
[1843] DTE brief, 169-70
[1844] DTE brief, 170
[1845] MAUI brief, 3-4
[1846] MAUI brief, 3

MAUI/PROTEC, citing the Scheduling Memo for Case No. U-21860, Attachment A, issued May 27, 2025.[1847]

Should DTE's rebuttal testimony be considered, MAUI/PROTEC asserts three reasons why the Commission should nevertheless adopt a disallowance. First, witness Hartley testified that DTE was addressing a backlog, but MAUI/PROTEC claims there was no direct testimony concerning a backlog. Second, Mr. Harley testified that the requested amount is justified due to volatility in the cost of materials. And third, if the justifications are valid, they apply only to Post Painting and not Post Inspection so the labor inflation rate would be the primary driver of cost increases.[1848] Thus, MAUI/PROTEC argues that increases should be confined to inflationary adjustments.[1849]

Although MAUI/PROTEC maintain that DTE's rebuttal testimony was improper, the appropriate way to address this concern was via a Motion to Strike. However, this PFD finds the Company's position persuasive as inflation-based projections may not, alone, be enough to properly account for the operational realities associated with these activities. Accordingly, MAUI/PROTEC's disallowance is rejected.

c. Supervisory and Administrative Costs

Mr. Schultz testified regarding the Company's proposed increase in supervisory and administrative overhead costs, as a proportion of the total direct O&M costs, expressing concern that DTE did not provide specific figures regarding the proportion of supervisory and administrative costs relative to the total direct O&M project costs.[1850]

[1847] MAUI brief, 4-5
[1848] MAUI brief, 5-6
[1849] MAUI brief, 6
[1850] 4 Tr 3759

Specifically, he objected to supervisory and administrative costs being approximately 28.0% of the total direct O&M project costs. Mr. Schultz determined that, as a percentage of total direct O&M, supervisory and administrative costs were 15.0% in 2023. Thus, he used this historical information to extrapolate the percentage of total direct O&M costs represented by supervisory and administrative costs to arrive at his recommendation to disallow $684,315 from the Company's request.[1851]

In rebuttal, Mr. Hartley testified that Mr. Schultz' proposed disallowance based on a fixed percentage of direct O&M costs from a single historical year would be an oversimplification that fails to reflect actual operational needs.[1852] Mr. Hartley explained that these costs "are driven by real-world factors such as staffing levels, oversight requirements, program complexity, and the scale of infrastructure being maintained or modernized. These factors are not tied to direct O&M expenditures in a linear fashion."[1853]

Mr. Hartley also pointed out that the O&M figure of $4,621,000 cited by Mr. Schultz in his extrapolation was sourced from a lighting working model containing outdated information; and the correct test year O&M amount is $4,584,000.[1854] According to him, the MAUI/PROTEC disallowance would represent a 45% reduction in spending and would "directly impair the Company's ability to manage outage restoration, conduct routine inspections, and perform preventative maintenance."[1855]

In its brief, DTE relies on the testimony of Mr. Hartley, reiterating that the Commission should reject the proposed disallowance because MAUI/PROTEC's

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[1851] 4 Tr 3760-3761
[1852] 3 Tr 1450
[1853] 3 Tr 1450
[1854] 3 Tr 1452
[1855] 3 Tr 1451

proposal relies on a simplified historical ratio that does not reflect actual operational needs or budgeting practices.[1856] Further, the proposed reduction would significantly impair the Company's ability to manage a complex lighting system, affect staffing, oversight, and maintenance activities, and compromise reliability, safety, and customer service.[1857]

In its brief, MAUI/PROTEC reiterates the testimony and rebuttal testimony of both parties and asserts that DTE failed to sufficiently justify the significant increase in Supervisory and Administrative costs.[1858] MAUI/PROTEC asserts that Mr. Hartley did not dispute that DTE was requested $1.4 million for Supervisory and Administrative costs, which by MI-MAUI calculations is approximately 28% of direct O&M project costs, up from 15% in 2023.[1859] MAUI/PROTEC therefore recommends that the Commission limit DTE to 15% or $769,685 for Supervisory and Administrative costs, for a disallowance of $684,315.[1860]

In its reply brief, the Company reiterated Mr. Hartley's testimony and asserted that the Supervisory and Administrative costs, while included as O&M expenditures, do not otherwise have a direct relationship, rendering MI-MAUI/PROTEC's linear comparison an arbitrary exercise.[1861] The Company repeated that the disallowance would have serious operational consequences for the Community Lighting program as the Supervisory and Administrative programs supports essential functions like staffing, oversight, scheduling, contractor coordination, and program management and requested the Commission

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[1856] DTE brief, 169-70.
[1857] DTE brief, 170.
[1858] MAUI brief, 7.
[1859] MAUI brief, 7.
[1860] MAUI brief, 7.
[1861] DTE reply, 162.

approve the Company's post painting and inspection and Supervisory and Improvement Programs as originally presented by the Company.[1862]

Having reviewed the record, this PFD finds that MAUI/PROTEC's argument to disallow $684,315 in supervisory and administrative O&M unpersuasive. This PFD agrees with the Company that the use of a single historical year without more to arrive at projected expenses alone is insufficient to justify the proposed disallowance. Therefore, this PFD recommends the Commission decline to adopt the proposed disallowance and approve the Company's supervisory and administrative costs related to Community Lighting.

d. Municipal Coordination

In his testimony, Mr. Chiu cited the Commission's order in Case No. U-21534 regarding municipal project coordination, directing DTE to: (1) "take proactive measures to inform municipalities and other utilities of projects it plans to commence prior to earmarking capital;" and, (2) "take proactive measures to investigate publicly available plans provided by other utilities and municipalities in an effort to coordinate work."[1863]

In response to this directive, Mr. Chiu testified that the Company has complied in a number of different ways. First, each community has a Regional Affairs manager, well known to community officials, serving as the designated liaison and first point of contact between DTE and the community.[1864] Additionally, the Company launched the Power Improvements Map (PIM) in 2024, which provides localized information to any

[1862] DTE reply,163.
[1863] 3 Tr 1125, citing order, p. 468.
[1864] 3 Tr 1126.

stakeholder on infrastructure repairs[1865] Finally, the Company is also contributing to the Michigan Infrastructure Council, which is developing a portal to assist authorized infrastructure asset owners, managers, private utilities, and state agencies to collaborate and coordinate.[1866]

Both MAUI and the City of Ann Arbor provided testimony in Case Nos. U-21297 and U-21534 on DTE's efforts at municipal communication and coordination.[1867] In the instant case, MAUI/PROTEC and Ann Arbor commented on Mr. Chiu's explanation of the Company's actions pursuant to the order in Case No. U-21534. MAUI/PROTEC witness Schultz testified that the Company has yet to comply with the Commission's order, whereas Ann Arbor witness Stults testified that the Company has complied with the Commission's directive.

After reviewing Mr. Chiu's testimony, Mr. Schultz testified that the Company has not demonstrated compliance with the Commission's order in Case No. U-21534, pointing to Mr. Chiu's statement that "The Company ***informs*** municipalities . . . of its forthcoming projects through a variety of existing engagement mechanisms."[1868] Mr. Schultz noted that "forthcoming" means "happening soon" and does not suggest any advance discussion on project planning, prioritization, or scheduling prior to earmarking capital.[1869] He further explained that Mr. Chiu described ways DTE meets with local officials to inform them of its projects, rather than coordinate with them.[1870]

[1865] 3 Tr 1126-1127.
[1866] 3 Tr 1127-1128.
[1867] 4 Tr 3762.
[1868] 4 Tr 3763.
[1869] 4 Tr 3764.
[1870] 4 Tr 3764.

Mr. Schultz further testified that the information provided in PIM is not timely nor detailed enough to allow for effective coordination and because local governments tend to plan in five year increments, while the Company has a shorter planning timeline.[1871] Additionally, projects posted in PIM already have funds earmarked, which fails to satisfy the Commission's directive to coordinate ***prior*** to earmarking capital for a project.[1872]

Because DTE is not in compliance with the Commission's order in Case No. U-21354, Mr. Schultz recommended that the Commission consider requiring the Company to document that it has reviewed local government's CIP and to discuss project prioritization and timeline with local officials before it commits design capital to a project, with a limited exception for projects that cost less than $250,000 net of customer contributions and emergent and storm recovery expenses.[1873]

In contrast, Ms. Stults testified that DTE made efforts to align its projects with the Ann Arbor's planned projects, and that the City and the Company have met to discuss improved coordination, as well as future coordination on planned infrastructure upgrades, capital projects and development review processes.[1874] She explained that Ann Arbor remains hopeful that establishing regular meetings with DTE will allow both entities to maximize efficiencies to the benefit of ratepayers and taxpayers.[1875] Ms. Stults stated that the City believes the Company to be in compliance with the Commission's order regarding municipal communication and coordination issued in Case No. U-21534.[1876]

[1871] 4 Tr 3765-3766.
[1872] 4 Tr 3766-3767.
[1873] 4 Tr 3768-3769.
[1874] 4 Tr 3738.
[1875] 4 Tr 3739.
[1876] 4 Tr 3729.

In their brief, MAUI/PROTEC reiterate the testimony of the parties and intervenors, as well as the history of the issue, before concluding that DTE has taken only nominal steps towards complying with the Commission's directive to improve communication and coordination with local governments.[1877] Specifically, MAUI/PROTEC notes four actions supporting their assertion: (1) DTE continues to earmark funds prior to reaching out to municipalities and other utilities; (2) by pointing to the PIM DTE shifts the burden to show reasonableness away from the Company to others; (3) projects posted to PIM already have capital earmarked for them; and (4) testimony from DTE witness Chiu reflects that DTE does not proactively review infrastructure plans for local governments or utilities.[1878]

After reviewing DTE's actions, MAUI/PROTEC recommend that the Commission take stronger action to require DTE to improve communication and coordination with municipalities on capital projects.[1879]

The Company's reply brief addresses the MAUI/PROTEC recommendation, supported by Ann Arbor, that the Commission require the Company to document its review of local governments' capital improvement plans and discuss prioritization and timing with local officials before committing capital, subject to reasonable exceptions, as a means to ensure compliance and identify cost savings and other efficiencies.[1880] The Company reiterates Mr. Chiu's testimony describing its municipal coordination efforts and his recommendation to reject the proposal to impose additional documentation requirements related to municipal coordination.[1881]

[1877] MAUI brief, 15-16
[1878] MAUI brief, 16-20
[1879] MAUI brief, 21
[1880] DTE reply, 221
[1881] DTE reply, 221-223

After reviewing the record on the issue of municipal coordination, this PFD finds that the Company has moved towards compliance with the Commission's order in Case No. U-21534 but can still do better. Therefore, this PFD recommends that the Commission renew its direction from Case No. U-21534, and instruct DTE to: (1) "take proactive measures to inform municipalities and other utilities of projects it plans to commence prior to earmarking capital;" and, (2) "take proactive measures to investigate publicly available plans provided by other utilities and municipalities in an effort to coordinate work."[1882] The Company should be reminded to take note of the Commission's order to take proactive measures ***prior*** to earmarking capital, and to continue its outreach and communication efforts with local units of government.

8. Customer Service Expense

a. Merchant Fees

DTE initially requested $7.013 million in the test year for residential merchant fees. In rebuttal, this request was withdrawn.[1883] While this issue is now moot, as is DTE's request for regulatory asset treatment, this PFD points out that Staff's Energy Affordability Report suggests that the Commission can decrease low-income customers' energy burden by disallowing or significantly modifying some or all fees, including fees to make credit card payments.

9. Uncollectible Expense

Mr. Sparks presented the Company's calculation of Uncollectible Expense (UCX).[1884] Mr. Sparks explained that UCX is the income statement impact of that portion

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[1882] MPSC Case No. U-21534, Order, p. 468.
[1883] 4 Tr 2675-2676.
[1884] 4 Tr 2734-2738.

of accounts receivable that is considered uncollectible from customers who use electric service; UCX arises from all sources of billed revenue.[1885] UCX is determined through a review of arrearage amounts and recorded using historical uncollectible rates as a reserve against accounts receivable.[1886]

To calculate its projected UCX expense, DTE used net write-offs of bad debt from 2021, 2022, and 2023 as a percentage of revenues to obtain the average ratio of 0.72%, which was then applied to projected revenues of $6.4 billion – resulting in an uncollectible account expense of $45.8 million.[1887] To which the Company added $1.2 million of net write-offs charged to other expenses and $1.0 million for amortization of costs related to the Low Income Payment Stability Plan (PSP) pilot, previously approved in the April 21, 2021, order in Case No. U-20929, for a total UCX of $48.0 million.[1888]

Mr. Rueckert recommended several changes to the projected UCX amount, supported by various Staff witnesses and presented in Exhibit S-24.1. Staff's methodology for calculating the projected UCX was the same as the Company's; however, Staff's projection included 2024 information.[1889] Additional Staff adjustments to UCX include: (1) using $5,854,370 as present revenue;[1890] (2) disallowance of the PSP amortization expense[1891] as part of UCX; and, (3) utilizing the Staff adjusted PSCR factor revenue.[1892] After incorporating adjustments, Staff recommends the Commission approve

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[1885] 4 Tr 2734.
[1886] 4 Tr 2734.
[1887] 4 Tr 3542; Exhibit A-13, Schedule C5.8.
[1888] 4 Tr 3542; 4 Tr 2737
[1889] 5 Tr 5191; 4 Tr 3542-4
[1890] 5 Tr 5192; Exhibit S-6, Schedule F2, page 2, line 49, column (b).
[1891] 5 Tr 5192
[1892] 5 Tr 5304

a UCX projection of $46,469,000[1893] and disallow $1,561,000 from the Company's request of $48.030 million.

Mr. Coppola adopted a similar approach to reach his recommended UCX amount; however, he updated the average to years 2022, 2023, and 2024. This resulted in an average of 0.71% which when applied to projected test year revenues of $6.4 billion resulted in a forecasted UCX amount of $45.4 million, to which he added $1.0 million for the PSP.[1894] Based on his adjusted calculation, Mr. Coppola recommended that the Commission set the UCX account expense for the projected test year at $46.4 million, or $1.6 million less than DTE calculated.[1895]

In rebuttal, Mr. Sparks did not object to the Staff's adjusted revenue contribution used to calculate the adjusted PSCR factor, or to Staff's recommendation to remove the PSP pilot amortization expense from the UCX calculation.[1896] However, the Company did object to the omission of the three-year average of direct expense from Attorney General Coppola's recommended adjustment.[1897] The Company did not provide any additional rebuttal on Staff's recommendation.

In its brief, DTE reiterates the testimony and rebuttal testimony of Mr. Sparks, which explained the methodology for calculating uncollectible expenses utilizing a historical three-year average (2021-2023) of the percentage of net write-offs to revenue applied to projected revenue (inclusive of PSCR Factor and surcharges) to project its uncollectible expense of $48.0 million. The Company objects to Mr. Coppola's exclusion

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[1893] 5 Tr 5192.
[1894] 4 Tr 3544.
[1895] 4 Tr 3543-3544.
[1896] 4 Tr 2742-2743.
[1897] 4 Tr 2742-27433

of the three-year average of direct expense, which adds back $1.2 million.[1898] The Company does not object to Staff witness Braunschweig's recommendation to allocate PSP amortization expense through the COSS calculations, removing $1.0 million from the uncollectible expense calculation. The net of the two adjustments DTE presents results in a $46.6 million uncollectible expense.[1899]

In its brief, Staff reiterates its adjustments to UCX as stated in the testimony of witnesses Rueckert and Braunschweig. Mr. Rueckert requested the Company update its projection to include 2024 expenses.[1900] Ms. Braunschweig supports disallowing the PSP pilot amortization expense and Staff witness Revere supports using Staff's adjusted PSCR factor revenue.[1901] In sum, Staff continues its recommendation that the Commission approve a UCX expense projection of $46,469,000.[1902]

This PFD concurs with Staff's recommendation to use $5,854,370 as present revenue, disallow the PSP pilot amortization expense as part of UCX, and use Staff's adjusted PSCR Factor. Having reviewed the record and in the absence of any Company objections to Staff's recommendation, this PFD approval a UCX projection of $46,469,000.

10. Regulated Marketing Expense

The Company projected $32.097 million of test-year O&M expense associated with Regulated Marketing, an increase of $11.125 million over the adjusted 2023 historical

[1898] DTE brief, 172-173
[1899] DTE Brief at 173
[1900] Staff Brief at 154
[1901] Staff brief p. 154-5
[1902] Staff brief p. 155

expense.[1903] Mr. Foley testified that this category includes expenses for Major Account Services, Electric Marketing, Economic Development, DR, TEP, and amortization of the Charging Forward regulatory assets.[1904] He testified that the Company applied a normalization adjustment of $6.382 million, representing temporary cost reductions in 2023.[1905] He further explained this adjustment:

> The details are listed in footnote 3 of Exhibit A-13, Schedule C5.9 and include $4.8 million related to a temporary pause of customer outreach to promote clean energy adoption, $1.0 million related to deferred hiring, and $0.5 million related to a temporary suspension of training and other expenditures related to research and best practice implementation needed to improve customer experience. These temporary reductions were taken to mitigate the financial challenges experienced by the Company in 2023 as further discussed by Witness Bruzzano and are not expected to recur in the projected test period.[1906]

a. Attorney General Adjustments

Based on Mr. Coppola's testimony, the Attorney General recommended adjustments to this expense. Mr. Coppola disagreed with the Company's method of forecasting the Regulated Marketing expense, arguing that it relies on outdated 2023 expense and contains problematic adjustments.[1907] In Exhibit AG-53, Mr. Coppola presented an alternative forecast using the Company's adjusted 2024 expense of $25.322 million.[1908] He testified that the Company's reported 2024 expense includes normalization adjustments for temporary reductions in customer outreach to promote clean energy and deferred backfilling of employee positions.[1909] He took issue with the

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[1903] Exhibit A-13, Schedule C5.9; 4 Tr 2653.
[1904] 4 Tr 2652.
[1905] 4 Tr 2652; Exhibit A-13, Schedule C5.9, line 15, column e.
[1906] 4 Tr 2652-2653.
[1907] 4 Tr 3538-3539.
[1908] 4 Tr 3539.
[1909] 4 Tr 3539.

Company continuing these expense reductions past 2023 and into 2024, arguing "the reductions are no longer temporary but reflective of a more permanent level of expense" and the "proposed normalization to a higher expense level is no longer credible."[1910] Mr. Coppola therefore removed the historical normalization expense of $4.909 million from his calculation of the 2026 O&M expense.[1911] After applying inflation for 2025 and 2026, he calculated a base Regulated Marketing O&M expense of $29.358 million (compared to the Company's projected $32.097 million) and recommended a disallowance of $2.739 million.

Mr. Coppola also recommended removal of the Company's proposed Other Adjustments to 2026 expense of $4.066 million for DR programs and $1.340 million for the Charging Forward program expansion.[1912] He testified that these amounts are the same as the amounts proposed from the 2023 historical expense base even though another year of cost increase occurred in 2024, noting that the Company spent $2.3 million more for DR in 2024 compared to 2023 and $1.0 million more for the Charging Forward program.[1913] He concluded, "Further increases in expense in future years is speculative at this time."[1914] In total, Mr. Coppola recommended a disallowance of $8.085 million from the Company's projected Regulated Marketing O&M expense.[1915]

In rebuttal, Mr. Foley testified in support of the Company's $4.909 million normalization adjustments.[1916] He stated that a $3.563 million adjustment related to

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[1910] 4 Tr 3539.
[1911] 4 Tr 3539.
[1912] 4 Tr 3540; see Exhibit AG-52, p. 2, column j and Exhibit A-13, Exhibit C5.9, column j.
[1913] 4 Tr 3540.
[1914] 4 Tr 3540.
[1915] 4 Tr 3540.
[1916] 4 Tr 2676-2678.

customer outreach to promote clean energy adoption is necessary because it will enable growth of the Company's MI Green Power program, which in turn offsets clean energy compliance costs and "helps create downward rate pressure on non-enrolled customers."[1917] He further stated that a $1.346 million adjustment related to deferred backfilling of employees that left the company is necessary to support a positive customer experience by ensuring that the Company has adequate resources to timely respond to its customers.[1918] Mr. Foley rejected Mr. Coppola's argument for removal of these adjustments: "AG Witness Coppola's argument seems to assume that if a reduction spans two calendar years, then it cannot be considered a 'temporary' reduction. This argument is illogical as there is no sound basis for why a temporary reduction would need to be confined to a single calendar year."[1919]

Mr. Foley next disputed Mr. Coppola's proposed disallowance related to the Company's Charging Forward program.[1920] He testified that the $1.340 million cited by Mr. Coppola represents a projected increase in EV program O&M spending from 2024 to 2026, which is comprised of a $0.124 million increase for Education & Outreach (E&O) and a $1.216 million increase for Program Administration.[1921] But Mr. Foley explained that in 2024, the Company's spending for E&O and Program Administration was split between O&M, regulatory asset, and capital treatment; when considering total 2024 spending, the Company's projected 2026 expense is just $0.505 million more than was spent in

[1917] 4 Tr 2676-2677.
[1918] 4 Tr 2677.
[1919] 4 Tr 2678.
[1920] 4 Tr 2678-2681. Mr. Foley explained that the Charging Forward program is now known as TEP. 4 Tr 2679.
[1921] 4 Tr 2679-2680.

2024.[1922] Mr. Foley also testified that the increase in O&M is supported by the Commission's December 1, 2023 order in Case No. U-21297, where:

> . . . the Commission adopted "the PFD and the ALJ's recommendation that the [14-person] Charging Forward program administration be made permanent and the requested funding be approved for the reasons stated in the PFD". Throughout 2024, the Company expanded its program administration team. As such, an increase in spending from 2024 (when the program administration team was not fully staffed) to 2025 and 2026 would be expected.[1923]

Mr. Leuker disagreed with Mr. Coppola's proposed disallowance of the $4.066 million DR adjustment.[1924] He testified that the adjustment involves increased spending for Smart Savers, Smart Charge, CoolCurrents, and DR pilots and other projects, for which he provided support in his direct testimony.[1925] Mr. Foley stated that the Company projects to spend $1.3 million more on the Smart Savers program compared to 2023 expenses, which will support nearly 25,000 additional enrolled devices and increase the program by an estimated 11 MW.[1926] Regarding the Smart Charge pilot, the Company plans to spend an additional $0.4 million to expand the pilot to analyze different value streams and to help determine whether the pilot should become a program.[1927] The Company projects an additional $0.8 million for the CoolCurrents program to fix 5,000 participating customers' 24v lines.[1928] And Mr. Leuker testified that the Company projects an increase of $1.5 million over 2023 levels to support additional DR programs and pilots,

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[1922] 4 Tr 2680.
[1923] 4 Tr 2680-2681, footnote omitted.
[1924] 3 Tr 1398-1399.
[1925] 3 Tr 1399.
[1926] 3 Tr 1399.
[1927] 3 Tr 1399.
[1928] 3 Tr 1400.

the dedicated DR call center, DR procurement efforts, and general marketing and incentives.[1929]

In its initial brief, DTE repeats the arguments presented by Mr. Foley to contest Mr. Coppola's treatment of the normalization adjustments and the Charging Forward O&M expense.[1930]

The Attorney General continues Mr. Coppola's argument that Regulated Marketing O&M expense should be calculated based on 2024 expense and should not include unsupported adjustments.[1931] Regarding the normalization adjustments, the Attorney General criticizes the Company for reducing costs in 2023 and 2024 but now proposing higher expenses for 2026 and disputes that those expenses are now necessary.[1932] Addressing Mr. Foley's claim that the increase in Charging Forward O&M expense is supported by the Commission's order in Case No. U-21297, the Attorney General retorts, "Simply because the Commission grants approval of a program in a certain form does not mean that any and all increased spending on that program in the future is reasonable, prudent, and recoverable from ratepayers."[1933] The Attorney General further argues that fewer EVs are expected to be purchased after the end of the federal tax credit, meaning "the TEP/Charging Forward program will be less active and expenses should be throttled back."[1934]

[1929] 3 Tr 1400.
[1930] DTE brief, 173-174, 214-216.
[1931] Attorney General brief, 112-113.
[1932] Attorney General brief, 114-115, citing Exhibit AG-87, pp. 1-2.
[1933] Attorney General brief, 114-115, citing Exhibit AG-87, p. 4.
[1934] Attorney General brief, 115.

In reply briefing, the Company again disputes removal of the normalization adjustment, it repeats Mr. Leuker's testimony supporting an increase in DR O&M expense, and it repeats previous arguments regarding the Charging Forward expense.[1935] In her reply, the Attorney General states that DTE ignores the "more recent, best available data" from 2024, which she reiterates should be used to calculate a more appropriate projection.[1936]

This PFD recommends that the Commission adopt the Attorney General's proposed Regulated Marketing O&M expense of $29.358 million for the 2026 test year. The Attorney General's calculation is appropriately based on more recent 2024 data, the use of which DTE does not directly oppose. However, this PFD disagrees with the Attorney General's exclusion of $4.909 million in normalization adjustments from the calculation.

Regarding the adjustments for DR and Charging Forward, this PFD finds that the Company provided adequate support for these expenses and therefore recommends against the Attorney General's proposed disallowance. Based on these recommendations, the Commission should disallow $2.739 million of test-year O&M expense, the difference between the Attorney General's projected $29.358 million and the Company's projected $32.097 million.

b. Staff Adjustments

Staff recommended that Regulated Marketing Expense be reduced by $544,000 for two items: (1) a dedicated DR call center ($300,000); and (2) a $244,000 reduction

[1935] DTE reply, 165-166, 199.
[1936] Attorney General reply, 51.

based on the application of Staff's inflation. As discussed above, this PFD found DR O&M expense to be adequately supported, including the DR call center.

11. Corporate Support

According to Ms. Uzenski, the Corporate Support Group (CSG) O&M expenses for Administrative and General services allocated to DTE Electric were $200.0 million for the 2023 historical test year and are expected to increase to $224.1 million for the projected test year.[1937]

Mr. Coppola forecasted the projected test year expenses for CSG O&M expenses for Administrative and General (A&G) services to be $193.3 million, $30.8 million less than the Company's forecast, including a $1 million reduction for federal funding compliance on the basis that most federal funds are currently under review by the new administration and no significant additional work in this area is necessary. [1938] In its brief, the Company accepted the Attorney General's $1.0 million O&M reduction related to federal funds compliance costs.[1939]

In addition to the adjustment discussed above, the DAAO recommended disallowance of voluntary corporate memberships.

Ms. Leslie testified regarding the inclusion of membership costs in the Company's revenue requirement, including those memberships in organizations involved in lobbying activities.[1940] She also sponsored Exhibit A-27 demonstrating DTE's purported compliance with the Commission's directive in Case Nos. U-21297 and U-21534. Ms.

[1937] 4 Tr 2442; Exhibit A-13, Schedule C5.10, line 10.
[1938] 4 Tr 3544-3545.
[1939] DTE brief, 175.
[1940] 3 Tr 1031-1035

Leslie testified that DTE acquires or maintains corporate memberships that support its "mission to provide safe, reliable, clean and affordable energy."[1941] Acknowledging that the Commission directed the Company to provide a discussion of actual processes, projects, procedures, or other tangible impacts benefitting customers that resulted from the listed corporate memberships, Ms. Leslie sponsored Exhibit A-27 to demonstrate DTE's compliance with the Commission's directive.[1942] Exhibit A-27, Schedule Q1, lists corporate memberships that exceed $100,000.[1943]

Ms. Leslie explained that the benefits received from these memberships largely fall within four categories: benchmarking, best practices, research, and networking.[1944] She testified that "memberships, or portions of memberships, related to lobbying activities are excluded from DTE Electric's revenue requirement," and only the portion of the membership fee exclusive of lobbying-related costs, is listed for recovery.[1945]

In addition to the information in Exhibit A-27, DTE provided testimony supporting its corporate membership recovery for Edison Electric Institute (EEI), Nuclear Energy Institute (NEI), Electric Power Research Institute (EPRI), and North American Electric Reliability Corporation (NERC). DTE asserts that the Company leverages EEI to benefit its customers by using it to forge connections with other companies in the EEI network resulting in mutual assistance coordination, initiatives and best practices, identifying and networking with diverse suppliers, benchmarking on utility-driven economic development,

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[1941] 3 Tr 1031
[1942] 3 Tr 1032; Exhibit A-27, Schedule Q1
[1943] 3 Tr 1031
[1944] 3 Tr 1033
[1945] 3 Tr 1032

solar and battery storage strategies and practices, UCX, surveys on tariff impacts, best practices on transportation electrification, and learning from industry experts.[1946]

Company witness Davis addressed membership in the NEI, stating it "assists in common issues impacting the nuclear industry," as well as the EPRI and the General Electric Boiling Water Reactor Owners' Group, stating it "sponsors research that is used by nuclear plans to operate safely and economically."[1947] Ms. Guillaumin also testified that membership in the EPRI provided access to benchmarking/best practice information, research, and networking opportunities; facilitating Company collaboration on technical studies that resolve critical industry issues. Ms. Guillaumin stated the costs of any one EPRI study would cost the Company more than the cost of membership, which makes membership cost effective.[1948] Mr. Kryscynski testified that membership in NERC, was "essential" for helping the Company remain compliant with mandatory reliability standards that directly support a stable and resilient grid for customers.[1949]

DAAO witness Nichols testified that DTE failed to support or adequately justify its request to recover discretionary corporate membership dues from ratepayers.[1950] DAAO asserts that DTE requests recovery of $17,560,352 in total corporate membership dues and $4,147,293 in discretionary membership dues.[1951] DAAO asserts that DTE has failed to provide any specific examples of customer benefits resulting from membership in several organizations, provided only generic or vague descriptions of customer benefits

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[1946] 3 Tr 2034-5
[1947] 3 Tr 493
[1948] 3 Tr 653
[1949] 3 Tr 1196-7
[1950] 5 Tr 4110
[1951] 5 Tr 4141

provided by several other organizations, and notes the supplemental testimony provided to support EEI, EPRI and NEI membership fails to state any specific achievements for customers as a result of access to those organizations' services.[1952] DAAO testified that the lack of transparency around how recipient organizations spend DTE's membership dues further undermines the Company's justification for recovery. Finally, DAAO notes this is the second rate case in which the Company has ignored the Commission's direction to provide information on how membership in these organizations has specifically impacted or benefited customers.[1953]

Focusing on EEI, for which DTE is asking to recover dues of $1,476,202, DAAO testified that EEI does not report an exact dollar amount spent on political advocacy and asserts that its advocacy undermines ratepayer interests.[1954] To support this assertion, DAAO points to EEI's opposition to solar energy and net metering, clean air and climate regulations, as well as efforts to limit competition and customer choice, support for bailouts of coal and nuclear plants, support for energy security plans, opposition to corporate transparency on emissions, and support for litigation against utility regulators and public interest groups.[1955] DAAO asserts that the Commission need not "take a position on energy or climate debates to identify that EEI's advocacy on these matters has been fundamentally concerned with financial outcomes for" shareholders, and not ratepayers.[1956] Finally, DAAO contends that the Commission's decision allowing DTE to recover the cost of EEI membership in Case No. U-21534 overlooked the fact that only a

[1952] 5 Tr 4143-4144
[1953] 5 Tr 4144
[1954] 5 Tr 4148
[1955] 5 Tr 4148-4150
[1956] 5 Tr 4150

fraction of DTE's membership dues fund services that benefit customers, and that the Commission should focus not on how EEI's advocacy impacts DTE, but how it impacts DTE's customers.[1957]

On rebuttal, Company witness Leslie specifically objected to DAAO witness Nichols' recommendations to disallow DTE's $1.5 million request for recovery of EEI membership dues, to closely examine other corporate membership requests, and to reject cost recovery for failure to comply with disclosure requirements for discretionary memberships as directed in Case Nos. U-21297 and U-21534.[1958] The Company asserts that DAAO's assessment of EEI is unsupported and should be rejected.[1959] Instead, DTE reiterates that EEI provides strategic business intelligence, conferences and forums for industry related questions, and invaluable resource information about the utility industry – services which provide the Company with valuable information such as utility benchmarking, best practices, networking and research, that the Company then uses to benefit its customers.[1960] Witness Leslie further notes that memberships or portions of memberships related to lobbying activities are excluded from DTE's revenue requirement[1961] and avers that Exhibit A-27 complies with the Commission's direction regarding corporate memberships.[1962]

In its brief, DTE reiterates and relies on Ms. Leslie's testimony and rebuttal testimony in asserting that the services provided by EEI provide the Company with

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[1957] 5 Tr 4151-4152
[1958] 3 Tr 1041
[1959] 3 Tr 1042
[1960] 3 Tr 1042
[1961] 3 Tr 1043
[1962] 3 Tr 1044

valuable information including “utility benchmarking, best practices, networking and research” which it uses to benefit its customers.[1963] The Company also asserts that memberships, or portions of memberships, related to lobbying activities are excluded from DTE Electric’s revenue requirement and that it has complied with the Commission’s direction in Case Nos. U-21297 and U-21534.[1964] Based on those assertions, the Company avers that its proposed recovery of corporate membership dues is appropriate and should be approved.[1965]

In its brief, DAAO argues that the Company has failed to meet its evidentiary burden and has violated the Commission’s orders in Cases No. U-21297 and U-21534 by failing to provide specific evidence of customer benefits derived from those memberships.[1966] DAAO reiterates its assertion that several of the discretionary memberships DTE for which is seeking recovery likely fund political advocacy counter to customer interest, which, because DTE is a local monopoly, constitutes compelled subsidization of political advocacy in violation of the First Amendment of the U.S. Constitution.[1967] For those reasons, DAAO concludes that the Commission cannot lawfully approve recovery for discretionary corporate membership dues.[1968]

In Case Nos. U-20836, U-21297, and U-21534, the Commission addressed concerns related to DTE’s recovery of corporate membership fees. In its November 18, 2022 order, the Commission directed DTE “to file in its future rate cases an exhibit

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[1963] DTE brief,175-6
[1964] DTE brief, 176
[1965] DTE brief,177
[1966] DAAO brief, 4
[1967] DAAO brief, 4
[1968] DAAO brief, 4

containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest."[1969] In its December 18, 2023 order, the Commission further directed DTE to provide "a detailed description of how these organizations *specifically* impact/benefit customers . . . which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization."[1970] In its January 23, 2025 order, the Commission directed the Company provide "a discussion of the actual processes, projects, procedures, or other tangible impacts benefitting the company's customers that have resulted from nondiscretionary corporate memberships."[1971]

This PFD finds that DTE has failed to comply with the Commission's direction in its November 18, 2022, order in Case No. U-20836, its December 1, 2023, order in Case No. U-21297, and its January 23, 2025, order in Case No. U-21534 to provide sufficient justification for why the majority of these costs are in customers' interest and how membership in these organizations specifically impacts or benefits DTE's rate paying customers.[1972] Although the Company has provided an exhibit listing its corporate memberships, the exhibit, and the testimony referenced within it, fails to list tangible benefits justifying why the costs are in the customers' interest or to list specific impacts or benefits membership provides to rate paying customers. Nor is there a discussion of actual processes, projects, procedures, or other tangible impacts benefitting ratepaying customers. Further, the Company asks the Commission to take at face value its assertion

[1969] November 18, 2022 order in Case No. U-20836, p. 308.
[1970] December 1, 2023 order in Case No. U-21297, p. 221.
[1971] January 23, 2025 order in Case No. U-21534, p. 466.
[1972] November 18, 2022 order in Case No. U-20836, p. 308. December 1, 2023 order in Case No. U-21297, p. 221. January 23, 3025 order in Case No. U-21534, p. 466.

that any costs associated with lobbying activities have been excluded from its recovery request without providing any evidence of how corporate membership costs break down between lobbying activities and customer interests.

Therefore, this PFD recommends the Commission disallow the Company's recovery of $1,476,202 in O&M expense for EEI membership for failing to comply with the Commission's direction in the last three rate cases. This PFD also recommends the Commission reiterate its previous direction to the Company "to file in its future rate cases an exhibit containing an *itemized list* of projected costs associated with membership fees and justification for why these costs are in customers' interest (emphasis added),"[1973] to provide "a detailed description of how these organizations *specifically* impact/benefit customers . . . which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization,"[1974] and to include ""a discussion of the actual processes, projects, procedures, or other tangible impacts benefitting the company's customers that have resulted from nondiscretionary corporate memberships."[1975]

Lastly, this PFD recommends the Commission direct DTE to provide a detailed and itemized list of expenditures, with names of vendors and a detailed description of the nature of the expenses, of DTE's spending on electoral campaigns, advertising, marketing, lobbying, trade associations, and 501(c)(3) and 501(c)(4) non-profits.

12. Pension and Benefits

[1973] November 18, 2022 order in Case No. U-20836, p. 308.
[1974] December 1, 2023 order in Case No. U-21297, p. 221.
[1975] January 23, 2025 order in Case No. U-21534, p. 466.

DTE forecasts a test-year O&M expense of $67.815 million for Pensions and Benefits, compared to $75.564 million that was spent in the 2023 historical year.[1976]

As an initial matter, DTE presents uncontested proposals with respect to the Pension and Other Post-Employment Benefits (OPEB) expense categories. First, Mr. Fix testified that DTE's Pension costs are projected to increase from negative $52.003 million during the historical year to $38.551 million for the projected test year; after adjustments for the portion of costs capitalized and transferred, the projected pension expense is $19.872 million.[1977] DTE proposes to continue to defer the projected pension expense to an accumulated regulatory liability, as the Commission initially authorized in Case No. U-20836.[1978] Given the lack of dispute, this PFD recommends approving continuation of the pension deferral mechanism.

Next, DTE's OPEB costs are projected to increase from negative $24.168 million in the historical year to negative $21.971 million during the projected test year.[1979] Mr. Cooper explained that after adjustments for the portion of OPEB costs transferred and capitalized, the projected net OPEB expense is negative $12.954 million.[1980] The Company proposes to continue deferral of the projected negative net OPEB expense to the accumulated regulatory liability, consistent with the Commission's treatment in Case No. U-17767 and subsequent cases.[1981] In addition, Mr. Cooper testified that in Case No. U-21297, the Commission adopted a seven-year amortization of the Company's OPEB

[1976] Exhibit A-13, Schedule C5.11.
[1977] 3 Tr 1465-1466, citing Exhibit A-13, Schedule C5.12.1, line 17.
[1978] 3 Tr 1466; 4 Tr 2426; DTE brief, 177-178.
[1979] 3 Tr 1531, citing Exhibit A-13, Schedule C5.12.2; DTE brief, 178.
[1980] 3 Tr 1531-1532, citing Exhibit A-13, Schedule C5.12.2, line 17.
[1981] 4 Tr 2425-2426; DTE brief, 178.

regulatory liability as of December 31, 2022, which resulted in an annual amortization of $18.3 million and is reflected on Exhibit A-13, Schedule C5.12.2, line 19 as a reduction to OPEB expense.[1982] These issues are not disputed; therefore, this PFD recommends approving continuation of the OPEB deferral mechanism and adopting a negative OPEB expense of $18.3 million.

Several disputed issues are addressed below.

a. New Hire Voluntary Employees Beneficiary Association

Mr. Cooper testified that new employees are offered a voluntary employee benefit association (VEBA) program in lieu of DTE's traditional retiree healthcare plan and that VEBA costs are offset by avoided OPEB costs.[1983] He explained that the Company recognizes a true up of the estimate of the Company's liability for contributions to the VEBA that reflects final determinations of plan eligibility and any forfeitures by employees that leave the Company before the end of the 10-year vesting period.[1984] He stated that the Company experienced an unusually large true-up adjustment for 2022 due to the COVID-19 pandemic, which was recognized in 2023.[1985] This 2022 true up (reflected as a reduction to the 2023 VEBA costs) was $2.920 million, compared to the average of the five prior years true-up adjustments of $0.439 million.[1986] Mr. Cooper continued, "Accordingly, the Company's 2023 costs were thus understated by the difference between the 2023 actual and the five-year average of $2.481 million, which after reduction for the

[1982] 3 Tr 1532, also citing Exhibit A-13, Schedule C5.11, line 3; see also 4 Tr 2426; DTE brief, 179.
[1983] 3 Tr 1533.
[1984] 3 Tr 1534.
[1985] 3 Tr 1534-1535.
[1986] 3 Tr 1535.

proportion of costs capitalized in 2023 of 44.6%, understated the Company's expense by $1.375 million."[1987]

The Company calculated its VEBA expense by first normalizing the 2023 expense and then projecting this expense through the test year.[1988] Mr. Cooper testified that the VEBA expense was projected to increase from the adjusted 2023 expense of $6.781 million to $8.086 million in the test year ($7.777 million after adjusting for the Voluntary Separation Incentive Plan (VSIP)), representing an average annual increase of 6.1%.[1989] He stated the increase reflects the growth in the number of participants due to new hires.[1990]

Staff witness Rueckert testified that the Company's actual five-year average annual growth rate through 2024 for total VEBA expense was 3.5%.[1991] He recommended applying this growth rate to the total 2024 expense amount, opining that the 2024 unadjusted basis is "fair and reasonable" when compared to the historical expenses shown in Exhibit S-24.4.[1992] On this basis, Staff recommended a disallowance of $1.775 million.[1993]

Attorney General witness Coppola also disagreed with the Company's forecast, describing it as "excessive" and "at odds with normal historical growth."[1994] He testified

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[1987] 3 Tr 1535.
[1988] 3 Tr 1536; DTE brief, 179.
[1989] 3 Tr 1536; Exhibit A-13, Schedule C5.11, line 4; DTE brief, 179.
[1990] 3 Tr 1536.
[1991] 5 Tr 5194; Exhibit S-24.4, line 19.
[1992] 5 Tr 5194.
[1993] Mr. Rueckert recommended a total reduction of $7.136 million to Account 926 Pension and Benefits, which includes his recommended disallowances to the VEBA, Employee Savings Plan, and Other Employee Benefits categories. 5 Tr 5194. Exhibit S-24.3 shows Staff's proposed disallowance for each category.
[1994] 4 Tr 3548.

that he started his calculation using the actual 2024 expense, which "avoided the problem of 2023 'True up' credits that were a factor in Mr. Cooper's analysis."[1995] He then increased the 2024 expense at a 1.5% annual rate to reflect historical growth.[1996] Mr. Coppola further increased the cost by 1.7% per year over two years to reflect expected employee population growth.[1997] This resulted in forecasted 2026 VEBA expense of $5.969 million, which is $1.8 million lower than the Company's projection.[1998] Mr. Coppola therefore recommended removal of $1.8 million from the Company's forecasted O&M expense for the test year.[1999]

In rebuttal, Mr. Cooper testified that both Mr. Rueckert's and Mr. Coppola's approaches were flawed because they rely on unadjusted 2024 VEBA costs as a starting point, without any normalization for the impact of excess true ups recognized in 2024 and the impact of lag hiring[2000] on VEBA expense.[2001] Mr. Cooper faulted Mr. Rueckert for using the historical average of actual percentage changes in the Company's VEBA costs instead of the actual number of VEBA participants and projected increases in participants.[2002] He stated that Mr. Coppola's use of a compound annual growth rate between 2020 and 2024 represents too short of a period because it excludes 2019 VEBA

[1995] 4 Tr 3548. Mr. Coppola's calculation is contained in Exhibit AG-56.
[1996] 4 Tr 3548. Mr. Coppola's annualized historic cost growth is based on the average annual increase of VEBA expense from 2020 to 2024. See Exhibit AG-56.
[1997] 4 Tr 3548.
[1998] 4 Tr 3548.
[1999] 4 Tr 3548.
[2000] Mr. Cooper explained that DTE implemented the VSIP in early 2024, which reduced the Company's workforce. In connection with the workforce reduction, the Company anticipated hiring new employees in certain strategic areas and replacing employees in areas where VSIP participation was greater than planned, resulting in open positions at year end 2024. Mr. Cooper adjusted the historical year VEBA expense to account for this lag hiring. 3 Tr 1558; Exhibit A-36, Schedule AA1, column e.
[2001] 3 Tr 1559, 1564.
[2002] 3 Tr 1559.

costs.[2003] Additionally, Mr. Cooper testified that Mr. Coppola's use of a compound growth rate is inconsistent with the Commission's practice of using the average of the annual percent change in costs, which would produce an annual escalation rate of 2.3%.[2004]

Mr. Cooper testified that the Company also recognized an unusually high level of true ups in 2024, resulting in a normalization adjustment of $1.247 million.[2005] He explained:

> The basis for this normalization adjustment is reflected in Exhibit A-36, Schedule AA2, which shows the five-year average of actual true ups recognized for the years 2017 through 2021 of $0.439 million compared to true up recognized in 2024 of $2.734 million. This produces an excess true up in 2024 of $2.295 million, which after adjustment for the portion expensed, results in a normalization adjustment of $1.247 million.[2006]

Mr. Cooper proposed using a five-year average of VEBA true ups for the years 2017 through 2021 because the true ups in 2022 and 2023 were also unusually high.[2007] He testified that for the years 2016 through 2019, annual forfeitures averaged less than $0.5 million; in 2020, due to the COVID-19 pandemic, forfeitures were less than $0.1 million; and the average annual forfeitures in the years 2022 and 2023 grew to $2.614 million, "which reflects a continuing transition from the COVID-19 pandemic that isn't representative of a normal level of forfeitures."[2008] Mr. Cooper testified that in DTE's most recent rate case (Case No. U-21534), the Company made a normalization adjustment based on the five-year average of true ups for the years 2017-2021, without objection by

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[2003] 3 Tr 1560.
[2004] 3 Tr 1560.
[2005] 3 Tr 1561; Exhibit A-36, Schedule AA1, AA2.
[2006] 3 Tr 1561.
[2007] 3 Tr 1561.
[2008] 3 Tr 1562; Exhibit A-36, Schedule AA3.

any party.[2009] Mr. Cooper also noted that in that case, the Commission recognized the impact of the COVID-19 pandemic by excluding the years 2021 and 2022 from the historical average used to project the Employee Savings Plan expense; he opined that the Commission's conclusion regarding that issue is equally applicable here.[2010]

Mr. Cooper testified that after accounting for excess true ups and the effect of lag hiring, the Company's adjusted VEBA costs have increased by an average of 7.82% over five years, with a compound average growth rate of 7.55% (compared to the 1.5% computed by Mr. Coppola).[2011] Mr. Cooper recomputed Mr. Rueckert's projected VEBA expense based on the normalized 2024 starting point and the 7.82% annual escalation, resulting in a projected expense of $8.150 million, which is $2.148 million more than Mr. Rueckert's projection.[2012] He testified that this adjusted VEBA expense is comparable to the Company's projection of $7.777 million, "which supports the reasonableness of the Company's original projection."[2013]

In briefing, DTE reiterates the arguments presented by Mr. Cooper.[2014]

In its brief, Staff argues that the Company erred by applying a true up to the 2023 VEBA expense, "obfuscating two consecutive years of decline," and then by applying a growth rate that is above what the Company has experienced.[2015] It argues that Mr. Rueckert's application of a five-year average annual growth rate to the unadjusted 2024 expense produces "a fair and reasonable projection" compared to historical expenses and

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[2009] 3 Tr 1563.
[2010] 3 Tr 1563.
[2011] 3 Tr 1565; Exhibit A-36, Schedule AA2.
[2012] 3 Tr 1565; Exhibit A-36, Schedule AA5.
[2013] 3 Tr 1565.
[2014] DTE brief, 179-181.
[2015] Staff brief, 171.

that adjusting the 2024 amount with a true up "increases the basis unreasonably higher than the prior three years of actual expenses."[2016]

In her brief, the Attorney General critiques Mr. Cooper's analysis for relying on true-up adjustments that are "outdated and no longer reflective of recent data," noting that true-up adjustments in the most recent three years have averaged $2.6 million yet Mr. Cooper uses an average five-year amount of approximately $0.4 million.[2017] The Attorney General states that by using a lower true-up adjustment, Mr. Cooper unreasonably increased the VEBA expense for the projected test year.[2018] She argues that Mr. Coppola's analysis relies on data provided by the Company for years 2020-2024, which, as confirmed by the Company through discovery, were net of the true-up amounts recorded in those years.[2019] The Attorney General explained, "Therefore, Mr. Coppola used adjusted recent VEBA expenses to calculate his proposed adjustment net of higher true-up adjustments, which lowered the historical expense and thus his forecasted expense."[2020]

DTE's reply brief repeats the arguments made by Mr. Cooper and by the Company in its initial brief.[2021] The Company continues to defend its normalization approach and argues that the surge in forfeitures seen in 2022 and 2023 "reflects the transitional impact of a once in a century pandemic" and is therefore "unrepresentative of a normal level of forfeitures."[2022]

[2016] Staff brief, 171, citing Exhibit S-24.4.
[2017] Attorney General brief, 122, citing Exhibit AG-75, pp. 1-2.
[2018] Attorney General brief, 122.
[2019] Attorney General brief, 122, citing Exhibit AG-75, p. 3.
[2020] Attorney General brief, 122.
[2021] DTE reply, 173-176.
[2022] DTE reply, 175.

Staff replies that while the Company claims it recognized an unusually high true-up adjustment in 2022 (resulting in understated 2023 costs), the Company made the same assertion in its previous rate case (Case No. U-21534) about the VEBA costs recognized in 2021.[2023] Staff concludes: "It is Staff's position that 3 years of consecutive and consistent true-up costs are not unusual or in excess as the Company claims and that using the 2024 unadjusted basis is a fair and reasonable starting point for the projection."[2024]

The Attorney General's reply brief repeats the arguments made in her initial brief.[2025]

This PFD agrees with Staff and the Attorney General that DTE's projected VEBA expense should be rejected because the Company's normalization adjustment is based on an outdated true-up average. Mr. Cooper arbitrarily concluded that the five-year average for the years 2017 through 2021 of $0.439 million represents the normal level of true ups that should be expected in the future, despite three consecutive years (2022-2024) of true ups exceeding $2 million.[2026] While he attributed the recent trend to "a continuing transition from the COVID-19 pandemic that isn't representative of a normal level of forfeitures," this PFD is not convinced that forfeitures will immediately return to the relatively low levels represented by the Company's five-year average or that exclusion of these recent years will result in an accurate projection. It should also be noted that the

[2023] Staff reply, 8.
[2024] Staff reply, 8-9.
[2025] Attorney General reply, 56-57.
[2026] The true ups recognized in 2022, 2023, and 2024 were $2.1 million, $2.9 million, and $2.7 million, respectively. Exhibit AG-75.

five-year average the Company proposes as representative of future true ups includes the year 2020, when forfeitures were less than $0.1 million due to the pandemic.

This PFD further recommends adopting the Attorney General's calculation as the most reasonable proposal for estimating the future VEBA expense. Mr. Coppola increased the 2024 actual expense by the annual growth rate for the years 2020 through 2024, net of the true-up amounts recorded in those years. He also increased the cost to reflect expected employee population growth. This approach appropriately utilizes the most recent available data, it takes into account projected increases in participants, and it avoids the Company's subjective true-up adjustment. In addition, DTE completely failed to explicate its claims that Mr. Coppola's calculation is deficient because it excludes 2019 costs or because his use of a compound growth rate is somehow "inconsistent with traditional Commission practice."[2027] The Commission should therefore disallow $1.8 million of test-year O&M expense.

b. Employee Savings Plan

DTE projects test-year O&M expense for its employee savings plan (ESP) of $29.953 million, an average annual increase of 4.5%.[2028] Mr. Fix explained that the ESP allows eligible employees to contribute a percentage of their annual earnings, which the Company generally matches up to 6%.[2029] In addition, employees hired after the Company's pension plans were closed to new hires receive an additional employer

[2027] DTE brief, 181; DTE reply, 175
[2028] Exhibit A-13, Schedule C5.11, p. 2, line 5; 3 Tr 1467.
[2029] 3 Tr 1466.

contribution of 4% of their pay.[2030] Mr. Fix described how he calculated the projected amount:

> The projected [ESP] expense was developed based on the total eligible employee earnings of active participants in the plans as of December 31, 2023, and the percentage of Company contributions. The eligible employee earnings was increased by 3.5% in 2024 and 3.0% in 2025 and 2026 to reflect the projected pay increases and the most recent five-year average of actual new plan participants prorated for the assumption that the new participants would be added evenly throughout the year (i.e., divided by two). The actual 2023 percentage Company contribution was applied to the adjusted eligible employee earnings to develop the annual [ESP] costs. These costs were reduced by the five-year average of employee forfeitures of unvested Company contributions. This results in total [ESP] costs of $57.084 million for the projected period. This amount is reduced by the proportion of costs capitalized of 45.4% to produce an [ESP] expense for the projected test period of $31.141 million, before the impact of the VSIP.[2031]

Mr. Rueckert testified that, as with the VEBA expense, Staff recommended applying a five-year average annual growth rate to the total 2024 ESP expense, opining that the 2024 unadjusted basis is fair and reasonable when compared to historical expenses.[2032] Staff therefore recommended a disallowance of $2.332 million, as shown in Exhibit S-24.3, line 12.[2033]

Mr. Fix responded in rebuttal that Mr. Rueckert erroneously used 2024 ESP expense as the starting point in his calculation, explaining that in 2024 the Company began recognizing the impact of forfeitures by employees who depart prior to vesting in the year the employee departed rather than in the subsequent year.[2034] He testified that as a result of this new accounting practice, in 2024 the Company recognized ESP

[2030] 3 Tr 1466.
[2031] 3 Tr 1467.
[2032] 5 Tr 5194; Exhibit S-24.4.
[2033] See 5 Tr 5194.
[2034] 3 Tr 1521.

forfeitures related to both 2023 and 2024, creating an unreasonably low 2024 ESP cost that must be adjusted before applying escalations. Mr. Fix also stated that Mr. Rueckert's calculation ignores the impact of lag hiring, as explained by Mr. Cooper and reflected in Exhibit A-36, Schedule AA1.[2035]

Mr. Fix testified that Exhibit A-55, Schedule VV3 shows the impact of normalizing 2024 costs by eliminating 2024 forfeitures (but not 2023 forfeitures) and by adjusting for lag hiring; he testified that these adjustments increase the five-year average from the 2.44% used by Mr. Rueckert to 3.54%.[2036] Mr. Fix also calculated an alternative analysis of the ESP expense by updating Staff's calculation with adjusted 2024 costs and a 3.54% annual escalation rate, which results in a test-year expense of $29.780 million ($2.159 million more than Mr. Rueckert's proposal).[2037]

In briefing, DTE relies on Mr. Fix's testimony to argue for the rejection of Mr. Rueckert's proposal and to alternatively recommend adoption of Mr. Fix's updated ESP expense of $29.780 million.[2038]

In its brief, Staff argues that Mr. Rueckert's application of a five-year average annual growth rate to the Company's unadjusted 2024 expense produces "a fair and reasonable projection," and it further opines that the 2024 basis is not unreasonably low as portrayed by the Company.[2039]

[2035] 3 Tr 1521.
[2036] 3 Tr 1521.
[2037] 3 Tr 1522; Exhibit A-55, Schedule VV5.
[2038] DTE brief, 183.
[2039] Staff brief, 171.

In reply briefs, DTE repeats its earlier arguments while Staff does not address this issue.[2040]

This PFD recommends adoption of the Company's alternative analysis of ESP expense, which starts with the more recent actual 2024 expense and applies a normalization adjustment to account for excess forfeitures due to a change in accounting practices and lag hiring. Staff failed to adequately address the Company's rebuttal testimony that provides justification for these adjustments. The alternative ESP expense is $29.780 million, compared to the Company's original projection of $29.953 million, requiring a disallowance of $0.173 million of O&M expense.

c. Healthcare Benefits

Mr. Cooper supported DTE's active healthcare expenses as shown in Exhibit A-13, Schedule C5.11. He testified that the Company's medical, dental, and vision benefits for active employees are projected to increase in the test year to $49,969,000 (after the application of VSIP).[2041] He stated that the increase includes two known and measurable adjustments to 2023 costs, as well as annual escalations. He testified that the first known and measurable adjustment is related to one-time items, which after capitalization resulted in a reduction to medical expenses of $450,000.[2042] The second known and measurable adjustment is the normalization of the Company's 2023 self-insured medical costs, which increases medical expenses by $2.409 million.[2043]

[2040] See DTE reply, 176.
[2041] 3 Tr 1537; Exhibit A-13, Schedule C5.11.
[2042] 3 Tr 1537-1538.
[2043] 3 Tr 1538.

Mr. Cooper asserted that this normalization is necessary because the year-to-year volatility of actual costs makes the historical average a poor predictor of future expenses and he presented a graph showing that the Company's actual active healthcare costs have changed relative to the prior year by as much as 27.2% in 2021 to a decrease of 4.5% in 2018.[2044] He testified that he disagreed with the Commission's finding in Case No. U-21534 that evaluating the actual and year-to-year changes experienced by the entire pool of employees provides a more reliable indication of future expenses than national trend data.[2045] According to Mr. Cooper, the Commission's reference to the entire pool of employees fails to distinguish the difference between the employees covered by fully insured healthcare plans, such as HMOs, which have relatively less annual volatility, and the Company's self-insured healthcare plans, which have high variability."[2046] He posited that because the cost of self-insured medical is dependent on usage in any given year, which can vary significantly between years, and unit costs, which tend to increase each year, the best way to normalize a specific year's costs is to create an average of historical usage and then apply the latest year's unit costs to that usage. He testified that this results in a normalized annual cost that is not distorted by the level of usage in the historical test year.[2047]

Mr. Cooper also provided testimony supporting the annual cost escalations of 4.55% for 2024, 4.05% for 2025, and 3.56% for 2026, noting that the escalations for the

[2044] 3 Tr 1538-1539, Table 1.
[2045] 3 Tr 1540-1541.
[2046] 3 Tr 1541-1542, Table 2.
[2047] 3 Tr 1542-1543.

Self-Insured Medical cost category are based on projections for healthcare trends provided by the healthcare experts at Willis Towers Watson (WTW).[2048]

Mr. Coppola testified that DTE's forecasted test year expense for active healthcare of $50 million is $6.8 million, or 16% over the 2023 actual expense of $43.2 million. He asserted that, while in prior years, the Company used constant dollar averaging (see CDA discussion above) to normalize active healthcare costs, which he noted was consistently rejected by the Commission, in this case, Mr. Cooper is proposing a "novel and unorthodox approach" to try to normalize historical health care expenses.[2049] Mr. Coppola called the new approach "very convoluted" and opined that it "introduces a very complicated calculation with granular source data that causes mismatches with recorded expenses and cannot be readily validated." Yet, he asserted, it still fails to solve the problem of volatile healthcare costs.[2050] Mr. Coppola testified further that he disagreed with Mr. Cooper's use of national health care cost trends instead of the Company's actual historical increases or the CPI-U inflation rate to forecast future healthcare costs.[2051] According to Mr. Coppola, the Company's approach unnecessarily inflates the forecasted amounts and makes them unreliable.[2052]

Mr. Coppola proposed what he called a "more reasonable" approach to forecast active healthcare expense that starts with the Company's 2024 actual expense of $45.4 million, increases it using CPI inflation rates for 2025 and 2026, and then adjusts it to account for a 1.7% growth in the employee base, resulting in a forecasted expense of

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[2048] 3 Tr 1545-1547, Table 3
[2049] 4 Tr 3549.
[2050] 4 Tr 3549-3550.
[2051] 4 Tr 3550.
[2052] 4 TR 3550.

$49.5 million.[2053] He recommended that the Commission remove $0.5 million from the Company's forecasted O&M expense.[2054]

In rebuttal, Mr. Cooper disagreed with Mr. Coppola's use of CPI inflation rates to escalate active healthcare expenses, explaining that there is a "long historical record of medical related costs increasing faster than overall inflation."[2055] Nonetheless, he testified that Mr. Coppola's forecasted test year expense of $49.456 million represents a total escalation of $4.019 million or an annual average increase of 4.4% for the two years, which is comparable to DTE's projections. Therefore, he therefore had no specific corrections to Mr. Coppola's recommendation.[2056] However, he noted that he disagreed with Mr. Coppola's assertion that the Company's self-insured medical cost adjustment is equivalent to constant dollar averaging. He stated:

> The constant dollar adjustment looked back on five years of the Company's actual Active Healthcare costs and adjusted each of those years' costs to current dollar by escalating the actual costs by the increases in nationwide healthcare related costs. The average of the restated Active Healthcare costs was used to adjust the historical test year's Active Healthcare costs to a constant dollar base. In contrast, the self-insured medical costs normalization adjustment addresses solely the medical costs of self-insured claims, which have a history of being the most volatile… Instead of repricing historical costs for the cumulative impact of changes in nationwide healthcare related costs, the self-insured medical adjustment uses current prices applied to the average historical units of unique medical services provided to the Company employees and dependents.[2057]

In surrebuttal, Mr. Cooper countered Mr. Coppola's assertion that his new approach does not correct for the volatility in active healthcare costs, stating that,

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[2053] 4 Tr 3551; Exhibit AG-57.
[2054] 4 Tr 3551.
[2055] 3 Tr 1568.
[2056] 3 Tr 1568.
[2057] 3 Tr 1569.

"[a]lthough no method is perfect, normalizing the Company's self-insured medical expense based on current costs and average number of medical services is superior to ignoring the potential for distortions in electing any single year's self-insured medical expense."[2058] He added that while his approach involves a significant level of detail, the calculations are not complicated and criticisms based on the mismatch of the underlying detail to the Company's recorded expense are not a sufficient basis to reject the method.[2059] He testified further that there is no basis to claim that the data used cannot be readily validated.[2060]

Both DTE's and the Attorney General's briefs restate their respective witnesses' testimony. The Attorney General adds that the Company's focus on the self-insured plan portion of medical costs and separating them from HMO and other medical insurance programs creates a potential problem for duplication of costs as employees transfer from one medical plan to another from year to year.[2061] She contends that Mr. Coppola's approach is simpler and more straightforward and results in a reasonable forecast that DTE has accepted.[2062]

The Attorney General's reply brief recaps her arguments, while DTE's reply corrects the Attorney General's assertion in her initial brief that DTE's new normalization proposal only pertains to the top 10 medical services under its self-funded health care program, which DTE deems is erroneous. DTE also argues that the Attorney General's contention that the Company's proposal creates potential problems if employees transfer

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[2058] 3 Tr 1574-1575.
[2059] 3 Tr 1575.
[2060] 3 Tr 1576.
[2061] AG brief, 124.
[2062] AG brief, 124-125.

between medical plans is unsupported, brought up for the first time, and must be disregarded.[2063]

As DTE agrees with the Attorney General's forecasted test year expense and recommended reduction, this PFD recommends that the Commission accept the Attorney General's disallowance of $0.513 million from the Company's projected active healthcare expenditure of $49,969,000 for the test year.

d. Other Employee Benefits

As shown in Exhibit A-13, Schedule C5.11, the Company's Other Employee Benefits are projected to increase from $12.933 million in 2023 to $15.250 million in the 2026 test year. Mr. Cooper explained that these costs include a variety of benefits such as Accrued Vacation, Wellness Program, Life Insurance, Long-Term Disability, fees associated with the Affordable Care Act, General Benefit, and Benefit Plan Administration Fees.[2064] At 3 Tr 1549-1552, he described his method for calculating the projected expenses for these various benefits. In addition, Mr. Fix testified that the Other Benefits category also includes Supplemental Severance Plan, Supplemental Savings Plan, Deferred Compensation, and Retirement Administration Fees; he further explained how he calculated the expenses associated with these benefits.[2065]

Mr. Rueckert recommended using the same method for projecting the Other Benefits test-year expense as he did with the VEBA and ESP, that is, application of a five-

[2063] DTE reply, 177.
[2064] 3 Tr 1548.
[2065] 3 Tr 1468-1471.

year average annual growth rate to the total 2024 expense amount.[2066] As a result, Staff recommended a disallowance of $3,028,000.[2067]

In rebuttal, Mr. Cooper objected to Mr. Rueckert's method of "amalgamat[ing] into one projection a variety of remarkably dissimilar benefits cost categories."[2068] He also faulted Mr. Rueckert for failing to adjust the 2024 benefits costs for known and measurable changes, as shown in Exhibit A-36, Schedule AA1.[2069] While Mr. Cooper opined that the Company's expense projection included in Exhibit A-13, Schedule C5.11 is the best projection, he stated that if the Commission prefers a projection based on actual 2024 expenses it should update Staff's projection to account for the known and measurable changes and individually develop projections of Other Benefits expense.[2070] He testified that he developed a normalized 2024 Other Benefits expense and then adjusted that amount for the Company's escalations based on the individual expense, which resulted in a projected expense of $14.773 million (compared to Staff's projection of $12.222 million).[2071] Mr. Cooper concluded that this adjusted expense was comparable to the Company's projected expense of $15.250 million, "which supports the reasonableness of the Company's original projection."[2072]

[2066] 5 Tr 5194.
[2067] 5 Tr 5194; Exhibit S-24.3, line 18.
[2068] 3 Tr 1566.
[2069] 3 Tr 1566.
[2070] 3 Tr 1566; Exhibit A-36, Schedule AA6.
[2071] 3 Tr 1567.
[2072] 3 Tr 1567.

DTE's initial brief reiterates the arguments and calculations presented by Mr. Cooper.[2073] Staff argues that Mr. Rueckert's method produces a reasonable projection compared to historical expense levels.[2074]

DTE's reply brief provides no new argument on this issue.[2075] Staff argues that the Company projected a 32% increase in Other Employee Benefits costs, which is "unreasonably large" compared to the 4.4% average annual growth rate of that category of expenses.[2076]

This PFD finds that Staff's proposed disallowance to the broad Other Benefits category of expenses should be rejected because it is based on an overly simplistic method that fails to consider the constituent 11 individual expenses, for each of which the Company has provided unrebutted evidence supporting its expense projections. This PFD further recommends that the Commission accept the alternative projected expense of $14.773 million, requiring a downward adjustment of $0.477 million from DTE's requested $15.250 million.

13. Employee Incentive Compensation Costs

DTE is requesting an expense of $56.369 million be included in the revenue requirement for the Company's short and long-term incentive compensation plans. DTE witness Fix testified regarding the Company's plans, noting that "$10.424 million of incentive compensation expense related to DTE Energy's Top Five Executive Officers has been excluded."[2077] Mr. Fix testified that DTE needs total compensation programs to

[2073] DTE brief, 185-187.
[2074] Staff brief, 171.
[2075] See DTE reply, 177-178.
[2076] Staff reply, 9.
[2077] 3 Tr 1482.

be able to compete with other employers and that without the incentive compensation programs, DTE's total cash compensation for its employees would not be reasonable.[2078]

Mr. Fix testified that incentive compensation plans are shown to motivate employees and improve organizational performance. He testified that such plans are typical in other companies, do not result in unreasonable compensation, and compared DTE's compensation to its peers in Table 1 of his testimony.[2079] Mr. Fix stated that the Company has short-term incentive plans provided through the Annual Incentive Plan (AIP) and the Rewarding Employees Plan (REP). DTE also has a multi-year plan available to managers and above pursuant to the Long-Term Incentive Plan (LTIP). In his testimony, Mr. Fix provided Table 2[2080], which summarizes the expenses for the incentive compensation plans in the projected test period, should all targets of the plans be achieved.

Mr. Fix testified that the AIP is offered to senior management level employees and uses a graduated payment method for hitting achievement levels from threshold to target, with a maximum level for results and corresponding payout. The 2023 measures and relative weights for the program are shown in Exhibit A-21, Schedules K2, K3, and K4.[2081] Regarding the REP, Mr. Fix testified that it is "identical to the AIP except that Threshold performance is at 50% of Target and the Maximum performance payout is 150% of Target."[2082] The 2024 measures and relative weights for the REP are shown in Exhibit A-

[2078] Exhibit A-21, Schedule K1.
[2079] 3 Tr 1485.
[2080] 3 Tr 1495.
[2081] 3 Tr 1486.
[2082] 3 Tr 1487.

21, Schedules K2, K3, and K4. Both programs have four categories of measures: financial performance, customer satisfaction, safety and engagement, and operating excellence.

In his testimony, Mr. Fix describes the measures pertaining to financial measures, customer satisfaction, employee engagement, safety, and operating excellence.[2083] He also described both the safety & engagement and operating excellence measures applicable to the Nuclear Generation business unit and noted that there are also AIPs and REPs for corporate staff employees at DTE LLC, the measures and weightings relating to which are shown in Exhibit A-21, Schedule K4.[2084] Mr. Fix testified that the performance share measures used for the 2024 LTIP are shown in Exhibit A-21, Schedule K5 and that those measures generally reflect the long-term financial performance of the Company. LTIP is distributed as grants of performance shares, based on the achievement of predetermined objectives, and restricted stock shares, exclusively based on the number of shares granted on the date of the grant.[2085]

Mr. Fix described restricted stock shares as not variable based on DTE's financial or operating performance. He stated that with restricted stock, "the ultimate payouts are not dependent on future Company or employee performance, and therefore, Restricted Stock is not regarded as an element of the Company's incentive compensation expense."[2086] As such, Mr. Fix did not include the restricted stock expense of $7.330 million on Table 2 in his testimony. Mr. Fix testified he does not agree with the Commission's findings regarding restricted stock in Case No. U-21534 and asserted that

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[2083] 3 Tr 1487-1490
[2084] 3 Tr 1491-1492.
[2085] 3 Tr 1493-1494.
[2086] 3 Tr 1496.

the restricted stock expense is unrelated to the Company's financial results and therefore should not be regarded as a financial measure. He further testified that "the cost recognized by the Company for the Restricted Stock upon grant is the same as if the Company had made a promise to pay cash"[2087] and asserted that restricted stock grants being convertible to common stock do not constitute a financial measure.

Mr. Fix testified that the Company has performed an analysis of the customer benefits resulting from the incentive compensation plans, the results of which are reflected in Exhibit A-21, Schedule K6 and show an aggregate benefit in excess of expenses by $39.566 million.[2088] He stated that Exhibit A-21, Schedule K6, Line 10 shows the benefits of the Company achieving its financial measures and testified:

> While the Company has not specifically quantified the benefits to customers of the other Financial measures, customers clearly benefit from the Company having access to the capital markets at favorable rates and terms, which is made possible through the Company being financially healthy.[2089]

Mr. Fix further testified that DTE determined the benefits of achieving target performance on the operating measures based on either the avoided costs to the Company or the value to customers of improved performance. He stated that the reference points for determining improvement are either based on actual performance during the historical test year, or historical average or peer performance when no historical test year data is available.[2090] Mr. Fix testified that the total quantified benefits related to the customer satisfaction measure are less then the related expense, but asserted that "an emphasis among the Company's employees on improving the

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[2087] 3 Tr 1497.
[2088] 3 Tr 1498.
[2089] 3 Tr 1499.
[2090] *Id*.

experiences customers have with the Company results in additional significant non-quantifiable benefits to both customers and the Commission."[2091]

Testifying further, Mr. Fix described how the Company determined the benefits resulting from the employee engagement measure and described the benefits to be expected if the Company hits its target level performance regarding the OSHA Recordable Incident Rate.[2092] Additionally, Mr. Fix described how the Company quantifies savings related to improvements in distribution system reliability and how the benefits from the general availability measure are quantified. Further, Mr. Fix provided testimony regarding the benefits of an increase in the Nuclear Annual On-Line Reliability Loss Factor (ORLF). Regarding the cost-effectiveness of DTE's incentive compensation plans, Mr. Fix stated, "As reflected on Exhibit A-21, Schedule K6, it is clear the quantified customer benefits of the Company achieving Target performance levels are substantially greater than the related expense."[2093]

Mr. Fix testified that in accordance with the Commission's directive in U-21534 to provide further explanation regarding the method used to determine the weighted results for 2019 through 2023, the Company created Exhibit A-21, Schedule K7 which shows the weighed results for those years and how those results were calculated for DTE Electric (see page 2). As an example of how actual results are determined that reflect the gradients of performance, Mr. Fix stated:

> In 2022, the percentage of Customers Experiencing Multiple Interruptions of four or more (CEMI4) Threshold performance level was 8.10%, the Target performance level was 7.55% and the Maximum performance level was 7.00%. The actual result in 2022 of 7.29% resulted in the REP

[2091] 3 Tr 1500.
[2092] 3 Tr 1500-1501.
[2093] 3 Tr 1503.

performance being 123.6%. The possible distribution of performance levels for this measure in 2022 are reflected in the chart in Table 3.[2094]

Mr. Fix testified that the performance levels are aggregated by dividing the sum of the performance results of the operating measures by the number of measures for each year. He testified that the performance results are summarized on line 11 of Exhibit A-21, Schedule K7, page one and that the average performance results for 2019 through 2023 was "79.3% for the AIP, 81.5% for the Executive AIP and 69.2% for the REP for a combined simple average of 76.7%."[2095]

Mr. Coppola assessed that the three incentive plans in question are too heavily skewed toward measures directly affecting shareholders, not customers. He noted that Mr. Fix's testimony shows that of the $56.3 million in requested incentive compensation expense, $35.8 million of that is tied to the Company's financial metrics. Mr. Coppola stated, "Regarding the AIP and REP, nearly half of the incentive payout at target level relates to DTE Electric achieving earnings and cash flow goals and DTE Energy achieving operating earnings per share."[2096] Mr. Coppola rejected DTE's argument that achieving these goals benefits customers, and noted that these goals are designed to increase cash flow to pay dividends to shareholders.

Additionally, Mr. Coppola testified that the measures pertaining to Customer Satisfaction represent only 15% of the total metrics, down from 20% of the total from last year. Mr. Coppola also testified that the measures in the Safety & Engagement category do not create direct customer benefits but are "primarily internal goals related to employee

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[2094] 3 Tr 1505.
[2095] 3 Tr 1507.
[2096] 4 Tr 3557.

satisfaction and deployment of safe practices in the workplace."[2097] Further, Mr. Coppola stated that the measures contained in the Operating Excellence category are basic operating goals that have limited direct visibility to customers. He testified that the only measures in this category with direct links to customers are the Electric outage metrics and the metrics pertaining to multiple customer outages. Mr. Coppola stated, "improvements in this area will be largely a function of a more aggressive tree trimming program and capital spending programs, which are paid for through increases in customer rates."[2098]

Turning to the LTIP, Mr. Coppola testified that this program is weighted 80% on total shareholder return, which is then measured against a group of peer companies to determine a payout. He stated that this does not create direct benefits for DTE customers, rather it creates value for the shareholders. Mr. Coppola further averred that the other measure involved, return on equity, "is also very removed from any quantifiable benefits that directly accrue to customers."[2099] Mr. Coppola rejected DTE's argument that that these measures will create a healthier company and therefore benefit customers.

Mr. Coppola also provided testimony regarding the customer benefits articulated by Mr. Fix to justify recovery of the incentive compensation programs. He examined Exhibit A-21, Schedule K6 wherein "Mr. Fix included a calculation which purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan

[2097] 4 Tr 3558.
[2098] *Id*.
[2099] 4 Tr 3559.

payments by $45.0 million."[2100] Mr. Coppola noted the exhibit shows the largest benefits in the area of Operating Excellence and in Employee Engagement.

Mr. Coppola testified that in 2024, DTE only reached the target performance for one third of the performance metrics on average for the area of operating metrics. He testified that the performance levels from 2024 raise uncertainty pertaining to the proposed incentive compensation in the instant matter stating, "if the Company's sub-standard performance levels continue into the projected test period, then a substantial portion of the incentive payments anticipated by Mr. Fix will not happen. "[2101] Mr. Coppola assessed that DTE has not shown that it has reached performance target levels consistently enough to justify recovery of 100% of incentive pay expenses relating to operational measures.

Mr. Coppola recommended that the Commission disallow $35.8 million in incentive compensation related to financial performance measures, and further recommended the Commission allow recovery of only a portion of the requested incentive compensation pertaining to operational performance measures. Mr. Coppola calculated that for the last five years ending in 2024, the Company achieved 49.4% of the target metrics or higher for non-financial measurement categories tied to incentive compensation.[2102] Therefore, he recommended that the Commission only approve 49.4% of the $20,531,000 requested for incentive compensation tied to operational metrics ($10,142,000) and make recovery of the remaining $10,389,000 subject to recovery under the 2-way Tracker Mechanism previously approved by the Commission. Mr. Coppola therefore recommended the

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[2100] *Id*.
[2101] 4 Tr 3560.
[2102] 4 Tr 3561-3562; Exhibit AG-59.

Commission adopt "a total disallowance of incentive compensation expense of $46,277,000 and the same reduction to the Company's forecasted O&M expense for the projected test year."[2103]

ABATE witness York testified that Table 2 in Mr. Fix's direct testimony shows that of the $56.369 million in incentive compensation requested by the Company, $35.838 million of that is tied to financial performance. She stated, "Incentive compensation programs that are designed to align the interests of employees with shareholders should be paid for by shareholders."[2104] Ms. York testified that the Commission has previously disallowed incentive compensation tied to financial measures, citing Commission decisions in Case Nos. U-20561, U-20836, and U-21534.

Ms. York referred to Exhibit A-21, Schedule K-6 and testified that "the costs associated with financial performance outweigh the benefits to customers in six out of seven metrics and cost $35.839 million but only provide $19.060 million in benefits to customers."[2105] Ms. York therefore recommended the Commission reject the inclusion of $35.839 million in incentive compensation tied to financial measures.

Regarding incentive compensation tied to operational performance, Ms. York referred again to Exhibit A-21, Schedule K-6 and stated that "there are certain components of the operational performance measures for which the benefits do not exceed the expense."[2106] She asserted that the expenses exceed the benefits for the Customer Satisfaction by $2.736 million and certain Safety & Engagement measures by

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[2103] 4 Tr 3562; Exhibit AG-60.
[2104] 4 Tr 3248.
[2105] 4 Tr 3249.
[2106] 4 Tr 3250.

$2.790 million. Additionally, Ms. York testified that "there are several Operating Excellence metrics for which the benefits do not exceed the costs (e.g., Generation Availability, and several nuclear-related metrics)"[2107], calculating the excess at $3.802 million. Ms. York therefore recommends the Commission reduce the projected test year incentive compensation related to operational performance by, at a minimum, $9.33 million.[2108]

Staff witness McMillan-Sepkoski testified regarding DTE's incentive compensation programs and noted that of the $56,369,000 in incentive compensation for the projected test-year ending December 31, 2026, $35,838,000 is related to financial performance measures and $20,531,000 is tied to non-financial operating objectives.[2109] She testified that the Commission has previously excluded incentive compensation related to financial measures because (1) the Commission found that incentive compensation plans tied to company earnings and cashflow were financial considerations which largely benefited shareholders and should not be paid for by ratepayers[2110], and (2) the Commission determined that "long-term incentive compensation is tied closely to company earnings and cashflow that benefits the shareholders more than the ratepayers."[2111]

Ms. McMillan-Sepkoski further testified that in Case No. U-17767, the Commission found insufficient evidence that the financial measures for short term incentives (AIP and REP) showed a significant benefit to ratepayers and that in Case No. U-20561, "the Commission has disallowed any capitalized amounts of financially measured incentive

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[2107] 4 Tr 3251.
[2108] *Id*.
[2109] 5 Tr 4980; Exhibit S-9.1.
[2110] Case No. U-14347, December 22, 2005 Order.
[2111] 5 Tr 4981; Case No. U-17735, November 19, 2015 Order.

compensation to be included in rates."[2112] Ms. McMillan-Sepkoski noted several Commission orders from 2018 through 2025 wherein the Commission has excluded financially measured incentive compensation from the revenue requirement and stated that it has done so on the basis that shareholders specifically benefit from financial performance measures while ratepayers specifically benefit from reliability and customer satisfaction measures.[2113] As such, she recommends the Commission find "inclusion of the EICP for non-financial performance measures for the amount of $20,531,000 is reasonable, however, $35,838,000 related to the achievement of financial performance measures should be disallowed."[2114]

Testifying regarding LTIP, Ms. McMillan-Sepkoski stated that LTIP is awarded with Restricted Stock or performance shares.[2115] She stated that both awards are based on DTE Energy company stock price (a financial measure used by the Company to determine the amount of the award) and that Restricted Stock "is considered as a reward to employees for supporting the Company's business objectives and long-term success."[2116] Ms. McMillan-Sepkoski testified that the amount of compensation in the form of Restricted Stock is $7,730,000, that the Commission has repeatedly disallowed any portion of compensation related to financial measures to be included in the revenue requirement, and that the Commission has found Restricted Stock as an expense that

[2112] 5 Tr 4981.
[2113] 5 Tr 4981-4982.
[2114] 5 Tr 4982.
[2115] 5 Tr 4982; Exhibit S-9.2, pages 3-4.
[2116] *Id*.

should be excluded. Therefore, she recommended the Commission disallow $7,730,000 of Restricted Stock from the revenue requirement.[2117]

In rebuttal, Mr. Fix disagreed with Mr. Coppola's analysis of the historical operating performance measures and stated that his analysis regarding the number of measures at target or above is flawed because it does not recognize how AIP and REP are designed. Mr. Fix testified that certain measures can produce results that are less than target and others can produce results that are greater than target. He stated that certain measures can still generate a payout even if the actual performance was less than the target, provided the performance was higher than the threshold level. Mr. Fix stated:

> Under the AIP, payouts range from 25% for Threshold performance to 175% for Maximum performance for non-executives, and up to 200% for executives, with 100% payouts for Target performance. Payouts under the REP range from 50% for Threshold performance to 150% for Maximum performance, with 100% payouts for Target performance.[2118]

Thus, Mr. Fix testified that Mr. Coppola's focus on whether or not a performance target was met is not representative of the impact of performance on actual payouts.

Mr. Fix pointed to Exhibit A-55, Schedule VVI as showing his calculations of the actual weighted operating performance for the last five years and stated that these results show a more accurate depiction of DTE's historical performance than what Mr. Coppola found in Exhibit AG-59. He testified that an assumption that the Company will only reach 49.4% of the operating measures is unreasonable and noted that in Case No. U-21534, the Commission rejected an identical proposal from the Attorney General.[2119]

[2117] 5 Tr 4983.
[2118] 3 Tr 1512.
[2119] 3 Tr 1512-1514.

Additionally, Mr. Fix testified that he disagreed with Ms. York's recommendation that incentive compensation related to operating measures that do not have a net customer benefit, the customer service and safety measures, be disallowed. He testified that her proposal is flawed because it "seems to rely on the flawed premise that all of the benefits 19 of the individual measures are capable of precise quantification."[2120] Mr. Fix stated that the quantified benefits as shown in Exhibit A-21, Schedule K6 reflect only the measurable benefits to the company and not the value of improved safety performance to the communities served by the Company. He further testified that "the measure of the benefits specifically excludes the immeasurable benefits of avoided fatalities"[2121] and asserted that the customer service and safety measures provide benefits that are not quantifiably measurable.

Further, Mr. Fix testified that Ms. York's proposal unreasonably interprets and applies the Commission's standard that only incentive compensation in which the benefits of the plan exceed the related costs be recoverable. Mr. Fix stated, "The Commission has consistently applied the standard articulated in the Order in Case No. U-10150 and assessed the net customer benefits on an aggregate basis without regard to the net benefits for each measure."[2122] He testified that Ms. York's proposal is unreasonable because it relies only on measurable benefits and is inconsistent with the Commission's traditional practice.

Mr. Fix also provided rebuttal to Ms. McMillan-Sepkoski's proposed disallowance regarding incentive compensation in the form of restricted stock. Referring to his direct

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[2120] 3 Tr 1515.
[2121] 3 Tr 1516.
[2122] 3 Tr 1517.

testimony, Mr. Fix stated that restricted stock is completely unrelated to the Company's financial performance.[2123] He testified that in Case No. U-21534, Ms. McMillan-Sepkoski determined restricted stock to be based on financial measures because the employee handbook stated that restricted stock was a reward for assisting the Company in reaching its financial performance goals, while in the instant matter she "cites an employee handbook that describes Restricted Stock as a reward to employees for supporting the Company's business objectives and long-term success."[2124] Mr. Fix testified that "business objectives and long-term success" refer to all aspects of DTE's operations, not just financial performance, and referred to Exhibit A-21, Schedule K2 for a summary of the Company's business objectives. Mr. Fix stated that while he believes that all incentive compensation should be included in the revenue requirement, he acknowledged the Commission's practice of excluding incentive compensation related to financial measures and suggested an alternative of disallowing "40% of the Restricted Stock expense related to the Financial measures in recognition that 60% of the Company's business objectives pertain to Operating measures."[2125] The result of taking this approach would be a disallowance of $3.092 million in restricted stock expense.

In its brief, DTE points to the testimony of Mr. Fix where he stated that after analysis, the Company determined that the incentive compensation programs provide an aggregate benefit of $95.935 million to customers, exceeding the expense of $56.369 million by $39.566 million.[2126] DTE argues:

[2123] 3 Tr 1517-1518.
[2124] 3 Tr 1518.
[2125] 3 Tr 1519.
[2126] DTE brief, page 188; Exhibit A-21, Schedule K6.

> Because the Company's overall employee compensation approximates the market, inclusive of incentive compensation, and the quantified customer benefits exceed the projected incentive compensation expense, the Company's total incentive compensation expense is a reasonable and prudently incurred expense that should be included in the revenue requirement adopted by the Commission in this proceeding.[2127]

Responding to the recommendations of Mr. Coppola, DTE argues his calculation pertaining to the percentage of operating measures achieved during the last five years is flawed because it assumes the operating metrics associated with the incentive compensation plan "are based on whether performance targets were met or not met (i.e., binary), when, in fact, a performance weighted average is the basis for the actual incentive compensation plan payouts that recognize there are gradients in performance levels."[2128] DTE points to the Commission's January 23, 2025 Order in Case No. U-21534 wherein the Commission rejected Mr. Coppola's binary approach, stating that such an approach ignores that DTE's incentive payout system is based on a gradation of meeting threshold, target, and maximum achievement levels. As such, DTE asserts the Commission should reject the Attorney General's proposed disallowance of $10.389 million in incentive compensation expense related to operating measures.

DTE relies on the testimony of Mr. Fix wherein he asserted that Ms. York's proposal to disallow incentive compensation where the related measures do not have a measurable net customer benefit is flawed. DTE argues that not all the benefits derived from individual measures are quantifiable and that Ms. York's proposal shows an unreasonable application of the Commission's standard regarding incentive

[2127] DTE brief, page 189.
[2128] DTE brief, page 190.

compensation only being recoverable when the benefits outweigh the costs.[2129] DTE therefore requests the Commission reject ABATE's proposed disallowance.

While acknowledging the Commission's disallowance of the restricted stock expense in Case No. U-21534, DTE points to the testimony of Mr. Fix where he testified that he does not agree with the Commission's conclusions and stated that the restricted stock expense is completely unrelated to the Company's financial performance. Relying further on Mr. Fix's testimony, DTE asserts that the restricted stock is granted as "shares of DTE Energy Common Stock and that the cost to the Company is the value of those shares on the date of grant, and therefore, is not variable based on the future price of DTE Energy's Common Stock."[2130] DTE argues that all incentive compensation should be included in the revenue requirement, but acknowledges the Commission's prior holdings and suggests that for the restricted stock, the Company would accept a disallowance of 40% of the expense, "consistent with the 40% weighting of financial measures within AIP and REP."[2131] This would reduce Staff's proposed disallowance regarding the restricted stock from $7.730 million to $3.092 million.

In briefing, the Attorney General asserts that the incentive compensation plans proposed by the Company skew too heavily toward measures that directly benefit shareholders as opposed to customers. She also argues that "the customer benefits presented by the Company are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved."[2132] Relying on the

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[2129] DTE brief, page 190.
[2130] DTE brief, page 189.
[2131] DTE brief, page 190.
[2132] Attorney General brief, pages 132-133.

testimony of Mr. Coppola from both the instant and prior matters, the Attorney General recommends the Commission disallow $35.8 million in incentive compensation tied to financial performance measures.

Regarding incentive compensation tied to operating performance measures, the Attorney General acknowledges the Commission's recent rulings in recommending the Commission allow recovery of a portion of short-term incentive pay related to those measures. However, she refers to Mr. Coppola's testimony and calculations regarding the Company's achievement percentage over the past five years and recommends the Commission only approve recovery of 49.4% of the $20,531,000 requested in incentive compensation related to operational performance measures, or $10,142,000. She further recommends making recovery of the remaining $10,389,000 subject to the 2-way Tracker Mechanism the Commission previously approved.

The Attorney General argues that the calculation Mr. Coppola used to determine DTE's average achievement rate during the last five years reflects an approach previously approved by the Commission. She disputes the Company's achieved performance level of 75.2% and notes that in a discovery response, "the Company confirms that the 75.2% includes measures achieved above 100%, which compensate for poor performance in measures achieved well below 100% of target."[2133] As such, the Attorney General argues Mr. Fix's calculation showing an achieved performance level of 75.2% uses an approach that was rejected by the Commission in Case No. U-21534. Arguing further, the Attorney

[2133] Attorney General brief, page 134; Exhibit AG-92, pages 2-7.

General states, “the substance of the Commission’s prior orders supports the AG’s approach and calculations, and the Commission should continue to approve it.”[2134]

The Attorney General recommends the Commission allow recovery of 49.4% of the $20,531,000, or $10,142,000, requested for incentive compensation tied to operational performance and make recovery of the remaining $10,389,000 for the operational metrics subject to recovery under the 2-way Tracker Mechanism previously approved by the Commission. In addition to the $35,800,000 recommended disallowance related to financial metrics, the Attorney General recommends a total disallowance of $46,277,000 for O&M expense related to incentive compensation.

In its brief, ABATE states that incentive compensation related to financial performance is “designed to align the interests of employees with shareholders and should therefore be paid for by shareholders.”[2135] ABATE argues that the Commission has consistently held as such and notes the Commission’s decisions regarding such in Case Nos. U-20561 and U-20836. ABATE asserts the Company has not shown in this case that customers benefit from incentive compensation tied to financial performance and that Exhibit A-21, Schedule K-6 shows that the costs associated with financial performance outweigh the benefits to customers in six out of seven metrics. Therefore, ABATE recommends the Commission disallow recovery of $35.839 million of incentive compensation tied to financial performance.[2136]

Arguing further, ABATE contends DTE is requesting recovery of incentive compensation tied to operational performance metrics which do not provide adequate

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[2134] Attorney General brief, page 135.
[2135] ABATE brief, page 55.
[2136] ABATE brief, page 56.

benefits to customers. Pointing to Exhibit A-21, Schedule K-6, ABATE argues that the benefits from the customer satisfaction and safety & engagement measures do not outweigh the expenses associated with each, and that the expenses exceed the benefits by $2.736 million and $2.970 million respectively. ABATE further asserts that there are several operating excellence metrics where the benefits do not exceed the costs, with a total net expense of $3.802 million.[2137] Therefore, ABATE recommends the Commission disallow $9.33 million in incentive compensation tied to these operational performance measures.

ABATE contends that DTE's argument that the Commission should consider benefits that are not able to be precisely quantified "is unreasonable and asks the Commission to approve millions of dollars of cost recovery on ethereal assumptions."[2138] ABATE argues that the unquantifiable benefits alleged by DTE cannot serve as the basis for issuing incentive compensation paid for by customers and states that DTE's "proposals to charge customers for incentives based on unquantifiable benefits and a holistic view that forgives costly components which do not provide adequate customer benefits is unreasonable and should be rejected."[2139]

In its brief, Staff relies on the testimony of Ms. McMillan-Sepkoski and recommends the Commission disallow $35.838 million in incentive compensation tied to achieving financial metrics. Staff states that it "does not dispute the overall reasonableness of employee compensation but instead argues that there should be a

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[2137] ABATE brief, pages 56-57.
[2138] ABATE brief, page 57.
[2139] *Id*.

distinction on who pays based on the metrics included."[2140] Staff points to the Commission's decision in Case No. U-21534 and argues that the Commission's decision in that case to disallow incentive compensation tied to financial measures is consistent with prior Commission orders and that the Commission's reasoning should be applied to the instant matter.

Staff also recommends the Commission deny DTE's request to modify the incentive compensation deferral mechanism to include payout amounts above 100% of the target. Staff points to the decisions in Case Nos. U-21297 and U-21534, and states that the Commission has "repeatedly disallowed the financial portion of incentive compensation for recovery in rates, and the level of payout approved by the Commission for operational measures has been at 100% of target level."[2141] Staff further states that DTE did not address Staf's recommendations regarding the proposed modification to the incentive compensation deferral mechanism in rebuttal, and "therefore Staff assumes the Company is in agreement."[2142] This PFD agrees with Staff's position and notes that DTE did not address this issue further in testimony or briefing. Therefore, this PFD recommends the Commission adopt Staff's recommendation and deny DTE's request to modify the incentive compensation deferral mechanism.

Turning to the issue of restricted stock O&M expense, Staff relies on the testimony of Ms. McMillan-Sepkoski and recommends the Commission disallow $7.730 million for this expense. Staff argue that the value of the awards granted is dependent on DTE's company stock price and points to Exhibit S-9.2 as showing that these awards provide

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[2140] Staff brief, page 163.
[2141] Staff brief, page 164.
[2142] Staff brief, page 165.

greater value when DTE's stock price increases and dividends are authorized.[2143] As such, Staff asserts that "restricted stock rewards [recipients] for sustaining the Company's profitable growth, and link [recipients] rewards to long-term financial results."[2144] Therefore Staff contends that excluding DTE's restricted stock awards is consistent with the Commission's long-standing position of disallowing incentive compensation expenses related to financial metrics.

In its reply brief, DTE responds to the recommendations of Staff, ABATE, and the Attorney General to disallow $35.838 million in incentive compensation tied to financial measures. DTE argues it previously explained why it disagrees with this disallowance and points to the cost benefit analysis in Exhibit A-21, Schedule K6 as the document upon which the Commission should base its decision. In her reply, the Attorney General reiterates her recommendation that the entire $35.838 million in incentive compensation related to financial performance be disallowed as conforming to previous Commission decisions. Likewise, in its reply brief, ABATE restates its recommendation that the Commission disallow $35.838 million in incentive compensation tied to financial performance. Staff did not address this issue further in its reply brief.

This PFD agrees with the recommendations made by Staff, ABATE, and the Attorney General and agrees that a disallowance of incentive compensation tied to financial performance is in line with the Commission's prior decisions. DTE has not presented evidence to support revisiting the Commission's prior determinations regarding this subject and has not convinced this PFD that the disallowance should be rejected.

[2143] *Id*.
[2144] *Id*.

Therefore, this PFD recommends the Commission disallow $35.838 million in O&M expense for the Company's incentive compensation plans tied to financial performance.

DTE addresses Mr. Coppola's recommendation regarding his proposed disallowance of 49.4% of the incentive compensation tied to operational measures, stating that the Commission "declined to adopt Witness Coppola's binary model approach in Case No. U-21534 (Case No. U-21534 Order dated January 23, 2025, p 277) and the Commission should again reject that position here."[2145] DTE also asserts the Attorney General's brief mischaracterizes the Commission's Order in Case no. U-21534 and the Company's discovery responses pertaining to this topic. DTE argued in that case and the instant matter that the Attorney General's approach is flawed as it does not recognize the performance gradients from threshold to maximum and only quantifies measures where the target has been reached. DTE further notes that the Commission rejected the Attorney General's approach in U-21534 and declined the suggested disallowance.

DTE also takes issue with the Attorney General's contention that the Company's responses to discovery (found in Exhibit AG-93) show that the Company is not following the Commission's prior orders regarding calculating incentive compensation. DTE states, "DTE Electric disagrees that the Commission's Order in Case No. U-21534 supports the AG's proposed disallowance for operational measures and these AG arguments should be disregarded."[2146]

In her reply brief, the Attorney General points to the argument articulated in her initial brief. She continues to assert that the approach taken by Mr. Coppola to calculate

[2145] DTE reply brief, page 180.
[2146] DTE reply brief, page181.

incentive compensation for operation measures conforms to what the Commission has previously ordered. She asserts that the substance of the Commission's prior orders supports the approach and calculations suggested in this matter and states, "The Company continues to deny the use of this approved approach, relying in part on Commission language in a recent order that it was open to considering performance above 100% of target."[2147] The Attorney General contends that "This contradictory and confusing language from the Commission has given the Company an opening that it is attempting to exploit."[2148] The Attorney General therefore recommends the Commission allow recovery of 49.4% of the $20,531,000, or $10,142,000, requested for incentive compensation tied to operational performance and make recovery of the remaining $10,389,000 for the operational metrics subject to recovery under the 2-way Tracker Mechanism.

This PFD is persuaded by the argument articulated by DTE regarding the incentive compensation for operational metrics. In Case No. U-21534, the Commission rejected a substantially similar proposal from the Attorney General regarding incentive compensation based on operational measures. The Commission rejected the Attorney General's "binary approach" of judging a target as met or not, concluding that this approach ignores the graduated payout system employed by DTE. As the arguments offered by the Attorney General and DTE mirror those made in U-21534, this PFD finds that no new evidence or arguments have been made that would require the Commission to reverse its determination made in U-21534. Therefore, this PFD recommends the

[2147] Attorney General reply brief, page 58.
[2148] *Id*.

Commission reject the Attorney General's recommendation to disallow recovery of 49.4% of the $20,531,000, or $10,142,000, requested for incentive compensation tied to operational performance and make recovery of the remaining $10,389,000 for the operational metrics subject to recovery under the 2-way Tracker Mechanism.

DTE also addressed ABATE's additional proposed disallowance of $9.330 million associated with operational performance program measures. DTE contends that accepting ABATE's stance would "would disallow operational incentive costs that have both quantifiable and unquantified but important benefits to the customers and communities DTE Electric serves."[2149] Additionally, DTE argues the standard proposed by ABATE does not conform to the Commission's objective in determining if the costs for incentive compensation measures outweigh the benefits provided. The Company asserts it "has met its burden to demonstrate that its operational measure incentive compensation, in aggregate, meets this standard and full recovery of such costs should be allowed."[2150]

In its reply brief, ABATE contends that the Company's arguments in response to its proposal "effectively concede that these incentives do not produce quantifiable benefits in excess of their costs the Commission should disallow cost recovery for these amounts."[2151] ABATE asserts that its request to disallow $9.330 million in incentive compensation associated with operational performance should be accepted by the Commission because "Customers should not pay for incentives which relate to operational performance which does not benefit them, or where the benefits do not

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[2149] DTE reply brief, pages 181-182.
[2150] DTE reply brief, page 182.
[2151] ABATE reply brief, page 20.

exceed the costs."[2152] ABATE asserts the measures for which it is seeking a disallowance are not quantifiable and therefore should not be recovered.

In Case No. U-21534, ABATE raised this same issue and requested a disallowance of incentive compensation tied to operational measures where there is no quantifiable benefit. DTE argued the same points in that case, namely that not all benefits are quantifiable and that the Commission has previously addressed net customer benefits on an aggregate basis. In U-21534, the Commission declined to impose the disallowance proposed by ABATE. As the facts and arguments in the instant matter are substantial similar to U-21534, this PFD recommends that the Commission decline to disallow $9.330 million associated with operational performance program measures as in accordance with its decision in U-21534.

Finally in its reply brief, DTE addressed Staff's proposed disallowance of $7.730 million in restricted stock. DTE maintains that its restricted stock awards are not solely financial measures skewed to the benefit of shareholders over customers. DTE argues that "Restricted Stock grants are not variable based on the future price of DTE Energy's Common Stock; therefore, Restricted Stock expense is completely unrelated to the Company's financial results and, should not be regarded as a financial measure."[2153] DTE reiterates its offer "to accept disallowance of 40% of the Restricted Stock expense, consistent with the 40% weighting of financial measures within AIP and REP, as a reasonable alternative to the complete elimination of the Company's Restricted Stock expense."[2154] Staff did not address this issue further in its reply brief.

[2152] ABATE reply brief, page 21.
[2153] DTE reply brief, page 182.
[2154] DTE reply brief, page 183.

In Case No. U-21534, the Commission addressed this same issue. DTE argued in that case that the restricted stock payouts are not based on future company or employee performance and therefore are not part of incentive compensation. The Commission rejected DTE's argument and found Staff's to be persuasive. This PFD finds that DTE has not presented new evidence or argument that would necessitate a reversal from the Commission's prior determination regarding restricted stock. As such, this PFD recommends the Commission approve Staff's request to disallow compensation of $7.730 million in restricted stock.

D. Depreciation, Amortization, and Allowance for Funds Used During Construction (AFUDC)

The differences among the parties regarding depreciation reflect differences in the underlying plant balances, with no methodological disputes to resolve.

E. Property and Other Taxes

Ms. Wisniewski testified regarding the Company's method for calculation of property tax expense, and expense, as set forth in Exhibit A-13, Schedule C7.1.[2155]

Staff recommended a property tax expense of $344.320 million based on its various disallowances to rate base capital expenditures. In addition to this adjustment for differences in rate base, Mr. Hecht also removed property tax expense for intangible plant from distribution plant capital expenditures.

Mr. Coppola recommended that DTE's property tax expense be reduced by $9.235 million, largely based on his adjustments to capital expenditures. In Exhibit AG-20, his

[2155] 4 Tr 3140-3142.

method involved summing the Attorney General's capital expenditure disallowances for 2025 and previous years, and multiplying this by 96%, 50%, and a millage rate of 56.5.

In rebuttal, Ms. Wisniewski testified that the Attorney General's method was inappropriate because it failed to take into account that: (1) not all capital expenditures are taxed in the same way; (2) DTE excluded nuclear generation capital expenditures as non-taxable; and (3) DTE expenses its property tax liability over two years.[2156] She further noted the ABATE witnesses York and Fitzhenry also projected property tax adjustments, without sufficient supporting documentation regarding how they arrived at their respective amounts.[2157]

In response to Staff, Ms. Wisniewski observed that Mr. Hecht's method for calculating property tax expense is similar to the Company's method, however, certain adjustments for components of CWIP are not separately identified in his workpaper, and thus it was not possible to distinguish how certain multipliers are applied. She did not respond to Mr. Hecht's $1,954,924 adjustment for intangible plant.

In her brief, the Attorney General notes that Ms. Wisniewski did not provide any specific corrections in testimony or in response to discovery, and that when asked whether a simpler formula could be developed, DTE did not respond. Accordingly, the Attorney General reiterates her recommended disallowance.[2158]

Staff's brief states that it reviewed the record on this issue, and it concurs with DTE's rebuttal regarding the method for calculating property tax.

[2156] 4 Tr 3149-3150.
[2157] Id.
[2158] Attorney General brief, 140.

This PFD agrees with DTE that in its final order in this case, the Commission should implement the Company's method for calculating property tax expense, based on its final determinations, including Staff's unrebutted adjustment to intangible plant. As DTE pointed out, the Attorney General's calculation contains errors and omissions that render it unreliable.

F. Income Tax, Other Tax Expense and AFUDC

The differences among the parties' calculations of federal, state, local, and general tax, along with AFUDC, result from differences in projected revenues and expenses.

G. Rate Case Expense

Mr. Coppola testified that the costs incurred to prepare, file, and litigate rate cases are becoming significant, explained that the Company expenses these costs and recovers them through O&M expense in base rates.[2159] In this proceeding, the Attorney General requested the Company provide the total costs incurred to complete the last three rate cases, as well as number of hours spent by employees to prepare for this case and the amount paid to external consultants.[2160] In response, DTE provided the amount paid to external consultants for the last three cases: $170,000-$175,000 in 2022 and 2023, $570,000 primarily in 2024, and an expected cost of $1.3 million in the instant case. However, DTE indicated that it does not track time or internal costs spent on rate cases.[2161]

Using the cost of external consultants provided by the Company, Mr. Coppola extrapolated an estimated internal cost to complete the current rate case at $14.3

[2159] 4 Tr 3552
[2160] 4 Tr 3552
[2161] 4 Tr 3552-3553

million.[2162] In support of his proposal to disallow recovery of 50% of the $14.3 million in costs for this rate case, Mr. Coppola points to statutes in Connecticut and Colorado that exclude rate case expense from rate recovery and to New Jersey and Missouri with regulatory commission precedents splitting rate case expenses.[2163]

In rebuttal, Mr. Bruzzano specifically disagreed with Mr. Coppola's recommendation to disallow $7.1 million in rate case expense, asserting that rate cases are an "essential and integral part of providing service" to customers because cost recovery for investments is obtained through the rate setting process.[2164] Mr. Bruzzano acknowledged that because rate case filing requirements have expanded, and because intervening parties request additional analytical support and project details, the costs associated with rate cases have increased; however, shareholders would be penalized if the Attorney General's recommendation were adopted.[2165]

Regarding the examples provided by Mr. Coppola in support of his recommendation, Mr. Bruzzano maintained that they should be disregarded as incomparable to proceedings in Michigan.[2166] According to him, the purported "precedent" from other jurisdictions to justify a disallowance is misplaced because Michigan has no statute excluding rate case expenses, and the examples Mr. Coppola cited involve distinct (non-Michigan) legal frameworks, isolated settlements with no precedential effect, and staff reports acknowledging full recovery as appropriate for prudent costs.[2167]

[2162] 4 Tr 3553-3554
[2163] 4 Tr 3554
[2164] 3 Tr 1006-1007
[2165] 3 Tr 1007-1008
[2166] 3 Tr 1009
[2167] DTE brief, 195

As to the figure calculated by Mr. Coppola for disallowance based on cost-per-page, Mr. Bruzzano stated that the amount is arbitrary due to the deeply flawed and overly simplistic method used for the calculation.[2168] Lastly, Mr. Bruzzano explained that requiring the Company to track the time employees spend preparing rate cases would be overly burdensome and would not result in any benefits to customers, given that these costs are integral to ongoing operations and not avoided in the absence of a rate case filing.[2169] Overall, Mr. Bruzzano testified that adopting Mr. Coppola's recommendation "would be inappropriate and unfairly harm the Company by denying recovery of prudently incurred costs."[2170]

In its brief, DTE relies on Mr. Bruzzano's testimony, reiterating that the Attorney General's proposed 50% disallowance of rate case expense rests on an arbitrary methodology and has no precedent in Michigan utility regulation or applicable statute.[2171] The Company further maintains that preparing and filing rate cases is an essential component of providing safe and reliable service and securing recovery for the substantial, Commission-directed investments necessary to meet Service Quality and Reliability Standards; therefore, it is not a discretionary activity undertaken for shareholder benefit.[2172] And, the Company reasserts that the Attorney General's recommendation that DTE should track internal employee time spent on rate cases would burden Company employees without producing customer benefits, The Company therefore requests that the Commission reject all of the Attorney General's suggestions

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[2168] 3 Tr 1010.
[2169] DTE brief,195-196.
[2170] 3 Tr 1010.
[2171] DTE brief, 194-195.
[2172] DTE brief, 195

concerning Company rate case efforts and the recommended disallowance of an arbitrary "rate case expense" amount.[2173]

In her brief, the Attorney General reiterates the testimony on this topic and counters the rebuttal testimony of Mr. Bruzzano, asserting that his testimony was selective, evasive, and resistant to transparency.[2174] She opines that it should not be an insurmountable burden for Company employees to keep a log of hours spent on preparing and working on a rate case and charging a separate O&M expense account to facilitate a 50/50 split of the costs.[2175] The Attorney General avers that the Commission, intervenors, and customers deserve to know the cost of a rate case, and by requiring DTE shareholders to bear half the cost of the case, the Commission would both keep customers' costs a little lower, and incentivize DTE to be more judicious with its rate case filing expenses.[2176]

This PFD notes that the Attorney General's proposal that the Company be required to split the cost of the rate case has been made previously. In Case No. U-16794, the Attorney General proposed that Consumers be required to pay a portion of the costs associated with preparing and processing its rate case.[2177] In its June 7, 2012, order, the Commission rejected the Attorney General's proposal to disallow recovery of some part of the rate case cost.[2178] More recently, the Attorney General recommended a reduction to rate case preparation and litigation expense and a four-year amortization period

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[2173] DTE brief, 196.
[2174] Attorney General brief, 125-131.
[2175] Attorney General brief, 131..
[2176] Attorney General brief, 131
[2177] June 7, 2012 order in Case No. U-16794, p. 90.
[2178] Id. at 91.

because the forecasted expenses were significantly higher than the previous case.[2179] The ALJ found that the witness training expense of $150,000 should be disallowed, because there was no requirement for witnesses to be professionally trained.[2180] In its July 2, 2024, Order, the Commission adopted the ALJ's recommendation and disallowed the $150,000 expense, noting that the expense was not reasonable and prudent.[2181]

Pursuant to 460.6j(6), the Company has the burden to prove that their O&M expenditures are both reasonable and prudent. In responding to the Attorney General's proposal to split the expenses of the rate case between customers and shareholders, the Company disclosed its expenses and projected expenses for external consultants from 2022 through 2025, but asserted that internal costs were largely fixed and dedicated to ordinary operations.[2182] While this PFD does not find the Attorney General's rationale persuasive, this PFD does find that she has called attention to the exponential growth of Company spending on external consultants. Those expenses have grown significantly from $170,000 in 2022 and $175,000 in 2023, to $570,000 in 2024, to an estimated $1.3 million in the current case, without any justification for the outside expense from the Company identified in the record.

This growth in the expenses for external consultants, without information supporting the purpose of the consultants and the need for the Company to utilize said consultants, does not appear reasonable or prudent. Moreover, it is unclear why DTE lacks the requisite expertise in-house to testify about issues such as an appropriate

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[2179] July 2, 2024 order in Case No. U-21461, p. 173.
[2180] Id.
[2181] Id. at 175.
[2182] DTE brief,194-195

capital structure and cost of equity. Nevertheless, this PFD finds insufficient evidence in the record regarding the expense to recommend disallowance in this case. Therefore, this PFD recommends the Commission direct the Company to provide a detailed and robust description and justification for expenditures on external consultants in the next rate case.

H. Net Operating Income Summary

Based on the findings and recommendations above, this PFD estimates an adjusted net operating income of approximately $1,249,412,000 as shown in Appendix C to this PFD.

VIII.

REVENUE DEFICIENCY

Based on the findings and recommendations in sections IV through VII above, this PFD recommends finding a revenue deficiency of approximately $210.876 million, as shown in Appendix A.

IX.

OTHER REVENUE-RELATED ITEMS

A. Infrastructure Recovery Mechanism

The Commission first authorized DTE's distribution IRM in its December 1, 2023 order in Case No. U-21297. There, the Commission approved IRM treatment for five capital programs (Conversions, SRR, Breaker Replacement, Underground Residential Distribution (URD) Replacement, and 4.8 kV Circuit Automation), with total IRM investments of $61.865 million for the 13 months ending 12/31/2024 and $290.134 million in 2025. The Commission limited its approval to two plan years to allow the Company to

"better inform the potential continuation of the IRM" by incorporating potential insights from an ongoing discussion regarding PBR in Case No. U-21400 and the ongoing Liberty Audit in Case No. U-21305.[2183] The Commission also established new annual IRM planning and reconciliation processes, requiring the Company to file an IRM Investment Plan at least four months prior to the start of each plan year and directing that the IRM reconciliation be filed as a contested case proceeding.

In the Company's last rate case, Case No. U-21534, DTE proposed expanding 2025 IRM investments by $434.1 million and proposed a two-year extension with total investments of $530 million in 2026 and $720 million in 2027, which included the Company's request to incorporate PTMM into the IRM. The Commission ordered 2025 investments to remain at previously approved levels; it authorized DTE to extend the IRM through 2026, but the Commission declined an extension through 2027, finding that the one-year extension "achieves a reasonable balance between avoiding a disruptive lapse in the IRM and the Staff's argument that the findings of the distribution audit in Case No. U-21305 and the PBR docket in Case No. U-21400 should be incorporated into the next IRM."[2184] For 2026, the Commission removed funding for the Conversions program but otherwise maintained the same spending levels authorized for 2025, denying approval of PTMM for IRM treatment, resulting in total authorized investments of $104.322 million.

Here, DTE again proposes to extend the duration and expand the scope of the IRM. Mr. Willis described the Company's primary and alternative proposals to extend the IRM through 2029. He testified that through the primary proposal, the Company is seeking

[2183] December 1, 2023 order in Case No. U-21297, p. 289.
[2184] January 23, 2025 order in Case No. U-21534, pp. 301-302.

continued authorization for existing programs and new authorization for investments in PTMM and System Cable.[2185] As shown in detail in the table reproduced below,[2186] DTE proposes total investment levels of $588.4 million in 2027, $813.8 million in 2028, and $1,008.6 million in 2029 for six programs.[2187]

Program	Previously Approved			Proposed		
	2024	2025	2026	2027	2028	2029
Conversions	$1.6M	$185.8M	0	0	0	0
SRR	$5.5M	$53.8M	$53.8M	$105M	$115M	$120M
Breaker Replacement	$13.7M	$12.6M	$12.6M	$15M	$22M	$26M
URD Replacement	$14.6M	$13.5M	$13.5M	$15M	$20M	$26M
System Cable	--	--	--	$25M	$30M	34M
Distribution Automation	$26.4M	$24.4M	$24.4M	$165M	$250M	$320M
PTMM	--	--	--	$263.4M	$376.8M	$482.6M
Total	$61.9M	$290.1M	$104.3M	$588.4M	$813.8M	$1.008B

[2185] 4 Tr 1740. The Company's proposal to expand the IRM would result in the following capital programs: SRR, Breaker Replacement, URD Replacement, System Cable, Distribution Automation, and PTMM. Mr. Willis testified that Distribution Automation was previously authorized as 4.8 kV Circuit Automation for IRM years 2024 and 2025, and the Commission in Case No. U-21534 approved changing to the broader Distribution Automation program. 4 Tr 1736.

[2186] See, Table 2 at 4 Tr 1741.

[2187] Mr. Willis testified that the full detail of the Company's proposed investment and in-service levels is contained in Exhibit A-33, Schedule X1. In addition, the specific programs and investment amounts are supported by Company witnesses Stowe (SRR), Robinson (Breaker Replacement, URD Replacement, System Cable, and PTMM), and Rademacher (Distribution Automation). 4 Tr 1740-1741. The details regarding these specific programs are discussed above.

Mr. Willis testified that, “consistent with the Company’s long-term investment plans to meet its reliability objectives,” most of the Company’s proposed IRM increases are focused on PTMM and Distribution Automation.[2188]

Mr. Willis opined that a three-year extension of the IRM is appropriate given the customer benefits associated with the mechanism (including increased accountability, review and input, increased transparency, and investment certainty), the Company’s incorporation into its distribution plans of the findings from the Liberty Audit (discussed by Company Witness Chiu), and the Company’s enhanced stakeholder engagement (discussed below).[2189] Mr. Willis testified that the Company is not including a PBR proposal in this case because the issue is being concurrently addressed in Case No. U-21400, with the Company’s proposal filed on April 15, 2025 in Case No U-21909.[2190] He also testified that the Company’s proposed IRM investments are well supported by the EJ adjustments to investment prioritization described by Company Witness Kryscynski.[2191]

Mr. Willis testified about the Company’s decision to include PTMM in its IRM proposal:

> As described by Company Witness Robinson, PTMM is a key program supporting reliability improvements on the system and which will grow over the next several years. In addition, as described by Company Witnesses Chiu and Robinson, the distribution audit supported the role of the PTMM program in achieving improved reliability outcomes. In addition, as described by Company Witness Kryscynski, the Company utilizes environmental justice as an input into prioritizing these investments. As

[2188] 4 Tr 1740.
[2189] 4 Tr 1738-1739, 1742.
[2190] 4 Tr 1742.
[2191] 4 Tr 1742-1743.

> such, it is appropriate to include this important and growing program in the IRM.[2192]

Regarding System Cable, Mr. Willis provided the Company's rationale for its inclusion in the IRM:

> As described by Company Witness Robinson, System Cable and URD make up the Underground System Investment in System Equipment Replacement program. The Commission has previously approved URD within the IRM and it is appropriate to support the full underground portion of the System Equipment Replacement program in the IRM.
>
> In addition, and as expanded upon by Company Witness Robinson, the January 2025 Order [in Case No. U-21534] supported the Company's investments in System Cable and the benefits those investments have on customer reliability.[2193]

Mr. Willis testified that the Company's alternative 2027-2029 IRM proposal would reduce the portion of investments recovered in the IRM but does not change what the Company believes are appropriate investment levels for the programs.[2194] He explained that the alternative proposal maintains the same spending levels in URD Replacement, Breaker Replacement, and System Cable compared to the primary proposal but reflects a 50% reduction in investment levels for Distribution Automation, PTMM, and SRR.[2195] As shown in the table reproduced below, the alternative proposal would involve total authorized investments of $321.7 million in 2027, $442.9 million in 2028, and $547.3 million in 2029.[2196]

[2192] 4 Tr 1744.
[2193] 4 Tr 1744.
[2194] 4 Tr 1745.
[2195] 4 Tr 1745.
[2196] See, Table 3 at 4 Tr 1746. See also Exhibit A-33, Schedules X2 and X5.

Program	Previously Approved			Alternative Proposal		
	2024	2025	2026	2027	2028	2029
Conversions	$1.6M	$185.8M	0	0	0	0
SRR	$5.5M	$53.8M	$53.8M	$52.5M	$57.5M	$60M
Breaker Replacement	$13.7M	$12.6M	$12.6M	$15M	$22M	$26M
URD Replacement	$14.6M	$13.5M	$13.5M	$15M	$20M	$26M
System Cable	--	--	--	$25M	$30M	$34M
Distribution Automation	$26.4M	$24.4M	$24.4M	$82.5M	$125M	$160M
PTMM	--	--	--	$131.7M	$188.4M	$241.3M
Total	$61.9M	$290.1M	$104.3M	$321.7M	$442.9M	$547.3M

Mr. Willis made clear that the Company believes the primary proposal is reasonable and that a slower ramp rate is unnecessary, stating that the Company's IRM reconciliation filed in Case No. U-21845 "provides evidence that the process developed by the Commission and originally adopted in Case No. U-21297 is functioning as intended and providing the expected customer benefits" and further referencing the additional opportunity for stakeholder engagement provided by the Company's proposed enhanced stakeholder process.[2197]

Mr. Willis also presented an "alternative option for 2026," which would expand the 2026 IRM "to include the full amount sought for recovery in the instant case should the Commission find it appropriate to approve the capital in the IRM instead of base rates."[2198]

[2197] 4 Tr 1745-1746.
[2198] 4 Tr 1738, 1747.

Mr. Willis testified this option would allow the Commission to "mitigate any execution risk it sees" while allowing the Company to invest at required levels.[2199] As depicted in Table 4 at 4 Tr 1748, this option would add the PTMM program with $200 million of investment, increase investment for SRR by $46.2 million, and increase investment for Distribution Automation by $115.6 million. In total, the 2026 IRM investment levels would increase from $104.3 million to $466.1 million.

Regarding the enhanced IRM stakeholder engagement process, Mr. Willis presented two proposals to provide additional opportunities for input in the IRM process. First, the Company intends to host an IRM Technical Conference in October 2025 in conjunction with the 2026 IRM Plan Stakeholder session, during which the Company would solicit feedback on its planning approaches.[2200] Second, beginning with the 2027 Plan, the Company proposes that a stakeholder meeting be held before the IRM plan is filed to allow stakeholder input while the plan is in development.[2201]

Mr. Willis testified that the IRM surcharge should reflect the actual approved revenue requirement of the underlying investments which have not yet been moved into base rates.[2202] He explained the basis for the Company's proposed surcharge design and sponsored Exhibit A-33, Schedule X7, which contains the surcharges for each distribution cost of service class and rate schedule.[2203] Company Witness Vangilder provided testimony in support of the revenue requirement, sponsoring Exhibit A-33, Schedule X4 to support the calculation with respect to the Company's primary proposal and Exhibit A-

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[2199] 4 Tr 1747.
[2200] 4 Tr 1743.
[2201] 4 Tr 1743-1744.
[2202] 4 Tr 1748.
[2203] 4 Tr 1749.

33, Schedule X5 for the alternative proposal.[2204] He also explained the Company's proposal for reconciling actual investment to the investment proposed for IRM treatment in this case:

> At a high level, the Company is proposing that after the conclusion of each calendar year, the Company would calculate a revenue requirement based on total and in-serviced investments for the previous year. This actual revenue requirement would be compared to the revenue requirement ordered by the Commission and calculated in a manner consistent with Exhibit A-33, Schedule X4. If the actual revenue requirement is less than the ordered revenue requirement, it would represent an over-recovery to be returned to customers. Importantly, the amount of capital that can be placed into service for each program under the IRM construct is capped at the amounts proposed by Company Witness Willis and captured in my Exhibit A-11 33, Schedule X4 (page 1, lines 2-28). If the Company elects to invest and place into service capital above the amounts proposed in the instant case, it can request recovery of that additional capital in a future rate case.[2205]

In addition, Company Witness Cejas Goyanes testified in support of the Company's allocation of the revenue requirement to the various voltage classes, as detailed in Exhibit A-33, Schedule X6.[2206]

Mr. Willis testified that the Company filed its 2024 IRM Reconciliation on March 28, 2025 in Case No. U-21845, and the Company will propose that IRM capital investments be transferred into overall rate base in the first rate case after conclusion of that reconciliation proceeding.[2207] He stated that in this rate case, the Company is seeking recovery of investments made during the 2024 IRM Plan year that were beyond authorized IRM levels and that will not be recovered in the IRM surcharge, as supported

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[2204] 3 Tr 1595-1599.
[2205] 3 Tr 1599.
[2206] 4 Tr 2566-2568.
[2207] 4 Tr 1737.

by Company Witnesses Stowe, Robinson, and Rademacher and detailed in Exhibit A-12, Schedule B.5.4.8.[2208]

Mr. Evans testified that with respect to the Company's 2026 alternative option, Staff supported adding PTMM at the $200 million investment level (as discussed by Staff witness Boutet and addressed below).[2209] However, Staff recommended against increasing investment for Distribution Automation due to the adjustment recommended by Staff witness Shi.[2210] And Staff disagreed with increasing investment for SRR based on the June 12, 2025 order in Case No. U-21305, where the Commission encouraged the Company to include in its next DSP filing "a realistic and detailed actionable plan based on reasonable goals tied to investments, legitimate timelines, and criteria for when and where cable replacement should occur" and further requested that the Company provide "more data related to impacts and performance improvements" of its investments.[2211]

Mr. Evans testified that Staff recommended approving extension of the IRM through 2029 at investment levels consistent with the Company's primary proposal, with the exception of SRR, for which Staff recommended the Company's alternative investment level (50% of the primary proposal) "because the Company needs to provide a plan and more data as directed by the June 12, 2025 order in Case No. U-21305."[2212]

[2208] 4 Tr 1737-1738.
[2209] 5 Tr 5286.
[2210] 5 Tr 5286. As previously addressed in this PFD, Ms. Shi recommended that the Distribution Automation program's "implementation pace should be carefully managed" and that projected expenditures should be partially disallowed, including a disallowance of $92,477,223 from the 2026 requested amount of $115,625,000. She noted that her proposed disallowance does not affect the $24.4 million that was previously approved for inclusion in the IRM. 5 Tr 5000-5001.
[2211] 5 Tr 5286, quoting June 12, 2025 order in Case No. U-21305, pp. 10, 28. Staff's recommendation would result in total 2026 IRM authorized investments of $304.3 million, $200 million more than previously authorized.
[2212] 5 Tr 5287-5288.

Mr. Evans also recommended that the Distribution Automation investment levels for 2028 and 2029 be contingent on meeting the Commission's requirements set forth at page 36 of its June 12, 2025 order in Case No. U-21305, which involve providing in its next DSP the Company's strategy for improving safety and reliability to its 4.8 kV system prior to conversion, its planned timing for Viper recloser installation, and its assessment comparing tree trimming and other alternative measures.[2213] Mr. Evans added that the Commission could approve only one or two years if it finds a three-year extension is too long, and he noted Staff's position that the Commission can reduce a year's approved amounts in a subsequent rate case prior to that year occurring.[2214]

Mr. Evans further recommended that for 2027-2029, the rate of return associated with the IRM surcharge should be lower than the pretax rate of return as ordered in this case, but no lower than the short-term debt rate ordered in this case.[2215] He opined that a lower rate of return is appropriate because the Company has under-invested in its distribution system for numerous years, comparing the levels of investment made in the mid-2010s to the levels and projected levels in the mid- to late-2020s.[2216] He elaborated:

> The fact that distribution capital projections for the mid-to-late 2020s are 3-5 times larger than the spending that occurred in the mid-2010s points to the earlier spending being insufficient. And while Staff is not saying the projections for 2025-2028 are the correct amounts, they are probably closer in magnitude to what the system requires than the amounts that were spent a decade or more earlier. This indicates past under-investment in the distribution system that the Company has only recently begun to turn around. In addition, the Liberty report found large inspection backlogs for some components of DTE's system, which also points to insufficient past

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[2213] 5 Tr 5288. Staff's recommendation would result in total IRM authorized investments of $535.9 million in 2027, $756.3 million in 2028, and $948.6 million in 2029, including contingent investments for Distribution Automation of $250 million in 2028 and $320 million in 2029.
[2214] 5 Tr 5290.
[2215] 5 Tr 5288.
[2216] 5 Tr 5288-5289.

> investment in the system. Due to this previous under-investment, Staff believes that a lower rate of return should be built into the IRM surcharge.[2217]

Mr. Evans testified that applying a lower rate of return "would not be unprecedented in a distribution system program," citing the January 23, 2025 order in Case No. U-21534 where the Commission held that the Company's rate of return on its tree trim surge regulatory asset should remain at the short-term debt interest rate.[2218] He added, "Once these investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, Staff intends for the normal [rate of return] to apply."[2219]

Mr. Evans concluded by testifying that Staff supports the Company's proposed IRM Technical Conference and initial stakeholder meetings as described by Mr. Willis.[2220]

Staff Witness Gerken testified that should the Commission approve the Company's 2026 alternative IRM option, shifting capital expenditures to the IRM that would become part of the IRM surcharge calculation, it would decrease the Company's requested revenue deficiency by approximately $18.6 million.[2221] Mr. Gerken also recommended that "if the Commission approves the Company's 2027-2029 proposed IRM the rate to be used in the IRM's incremental revenue requirement calculation would be the rate ordered by the Commission."[2222]

Staff Witness Boutet testified in support of the Company's proposal to transition $200 million of 2026 test-year investments for the PTMM program into the IRM, opining

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[2217] 5 Tr 5289-5290.
[2218] 5 Tr 5290.
[2219] 5 Tr 5288.
[2220] 5 Tr 5290.
[2221] 5 Tr 4973.
[2222] 5 Tr 4973-4974.

that “the work included in the PTMM program is critical to improving the Company’s reliability performance in the near future, and it would be reasonable and prudent to ensure that every dollar possible is spent responsibly on this program for the good of customers.”[2223]

On behalf of MNAG, Mr. Alvarez recommended that the Commission reject DTE’s extension of the IRM beyond 2026. He testified that the IRM “has expanded from a niche cost recovery approach for a few well-defined programs ($61.9 million in 2024) to a massive capital spending program (over $1 billion by 2029),” and he “challenge[d] the wisdom of approving ever-increasing capital spending as a potential solution to poor DTE reliability.”[2224] Mr. Alvarez discussed regulatory lag, testifying that it provides value to utility customers while it is viewed by shareholders as something to avoid.[2225] He testified that the ratemaking practices of future test years and rider cost recovery reduces regulatory lag, as does DTE’s practice of filing annual rate cases.[2226] He opined that regulators’ interest in reducing regulatory lag is misplaced, and he disagreed that regulatory lag must be eliminated for utilities to secure capital at reasonable terms.[2227]

Mr. Alvarez testified, “While efforts to reduce regulatory lag are not in customers’ interest, I believe these efforts involve unintended consequences that are even more harmful to customers than reductions in regulatory lag.”[2228] He went on to discuss various unintended consequences of ratemaking practices designed to reduce regulatory lag:

[2223] 5 Tr 5148.
[2224] 5 Tr 4644-4645.
[2225] 5 Tr 4646.
[2226] 5 Tr 4647.
[2227] 5 Tr 4647-4648.
[2228] 5 Tr 4647.

• Advance regulatory review of utility investment plans, as required for future test years and IRM cost recovery requests, results in "the practical elimination of a regulator's ability to disallow costs from customer recovery" because once an investment plan is approved "it becomes almost impossible for the regulator to disallow the costs of any capital projects or programs included in that plan (other than cases of gross negligence in project/program oversight or malfeasance in procurement)."[2229]

• The elimination of cost disallowance risk associated with advance investment review introduces moral hazard into utility investment plan development, where "[a] utility has nothing to lose, and everything to gain, by proposing potentially imprudent projects and programs in an investment plan that the utility would not otherwise make if exposed to cost disallowance risk, as in traditional ratemaking . . . ."[2230]

• A shift of investment risk from shareholders to customers by the practical elimination of cost disallowance risk and the increased likelihood that utilities will include imprudent projects or programs in their investment plans.[2231]

• Increases in information and resource asymmetry caused by a lack of utility self-moderation with respect to capital spending. "Absent cost disallowance risk, intervenors must hire distribution expertise to identify inappropriate, or premature, or cost-ineffective, or inadequately supported capital project[s] or programs in advance, at the investment plan review stage."[2232]

• Placement of the Commission "in the unenviable position of making capital spending decisions" when it is required to determine the prudence of DTE's investments through advance review of investment plans.[2233]

Mr. Alvarez concluded that given future test years and DTE's frequent rate case filings, there is no need for an additional mechanism to reduce regulatory lag.[2234] He testified that DTE's reliability has not improved despite additional increases in capital

[2229] 5 Tr 4648-4649.
[2230] 5 Tr 4650.
[2231] 5 Tr 4651.
[2232] 5 Tr 4651-4652.
[2233] 5 Tr 4652-4653.
[2234] 5 Tr 4654.

spending that has been encouraged by the IRM.[2235] And he opined that the IRM "shifts the balance of interests between customers and shareholders that regulation is supposed to maintain decidedly in shareholders' favor."[2236] Mr. Alvarez recommended that the Commission "terminate the IRM as of December 31, 2026."[2237]

As previously addressed in this PFD, MNAG witness Stephens discussed his concerns with the Company's distribution grid capital spending plans, and he recommended against 2027-2029 IRM funding, or expanded 2026 funding for Distribution Automation, SRR, and PTMM.[2238]

After noting the "conceptual merit" for using an IRM where projected test years are permitted, ABATE witness Dauphinais testified about several concerns he has with DTE's proposal.[2239] While stating there was merit to adding an additional year to the IRM "to avoid the need for DTE to annually file a new rate case in order to continue its Distribution IRM," he cautioned against extending the IRM for two additional years beyond 2027 because it would "become highly speculative to predict and therefore improper to authorize" the appropriate forecasted amounts to be included in the IRM.[2240] He also identified concerns with single-issue ratemaking:

> Furthermore, such extended projections greatly increase the possibility of cost over recovery through single issue ratemaking as the cost recovery provided to DTE through the Distribution IRM surcharge does not consider whether DTE has decreases in expenses or increases in revenues versus those in the projected test year of its last rate proceeding that would offset

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[2235] 5 Tr 4654.
[2236] 5 Tr 4654.
[2237] 5 Tr 4654.
[2238] 5 Tr 4485-4529.
[2239] 4 Tr 3398-3399.
[2240] 4 Tr 3400.

a portion of DTE's revenue requirement for Distribution IRM investments.[2241]

Mr. Dauphinais took issue with what he described as DTE's proposal to "astronomically grow" its IRM investment levels from $104.3 million in 2026 to more than $1 billion in 2029, resulting in over a five-fold increase in 2027, over an eight-fold increase in 2028, and nearly a ten-fold increase in 2029.[2242] He testified that ABATE "is not opposed to some level of growth" but opined that DTE's proposed levels of investment growth "raise serious questions with respect to whether the proposed included investments are in fact urgently and undisputably needed and the most cost-effective way to address the needs that need to be met."[2243] He cautioned that expanding and extending the IRM as DTE proposes could result in the unreasonable and unnecessary expansion of distribution investments at ratepayers' expense.[2244]

Mr. Dauphinais next referenced Mr. Fitzhenry's testimony, testifying that even if DTE's BCA is accepted in this proceeding, at least $400 million of proposed Distribution Automation IRM investments for 2027 through 2029 and $739 million of proposed PTMM IRM investments "are not justified and highly questionable."[2245] He concluded: "This indicates that, as a minimum, the growth in annual investment in the existing Distribution Automation cost category should be significantly restrained and the proposed PTMM investment cost category should not at this time be added at all to DTE's Distribution IRM."[2246]

[2241] 4 Tr 3400.
[2242] 4 Tr 3400.
[2243] 4 Tr 3400.
[2244] 4 Tr 3400-3401.
[2245] 4 Tr 3401.
[2246] 4 Tr 3401.

Regarding DTE's alternative option for 2026, Mr. Dauphinais testified that it would result in a four-fold increase over the amount the Commission authorized in Case No. U-21534 and would "problematically" add investment for PTMM.[2247] He also stated that the proposal is "essentially a re-litigation of the outcome" of DTE's request in Case No. U-21534.

Mr. Dauphinais ultimately recommended that the Commission: (1) completely reject DTE's alternative option of expanding 2026 IRM investment; (2) completely reject DTE's proposal to extend the IRM to 2028 and 2029; (3) completely reject DTE's proposal to add the PTMM program to the IRM; and (4) limit 2027 investments to no more than DTE's alternative proposed 2027 amounts, with the exception of PTMM that should be completely eliminated.[2248] He testified that his recommendation does not stop growth of DTE's IRM investments, "but rather contains that growth to a much more reasonable level," noting that his proposal would result in DTE's authorized investments for 2027 being $85.7 million (82.2%) higher than the total authorized investments for 2026 in Case No. U-21534.[2249] If the Commission declines to adopt this recommendation, as an alternative Mr. Dauphinais recommended adoption of Mr. Fitzhenry's adjustments to DTE's primary proposal amounts for Distribution Automation (reductions of $55.5 million in 2027, $138.2 million in 2028, and $205.9 million in 2029) and PTMM (reductions of $138 million in 2027, $248.8 million in 2028, and $351.9 million in 2029).[2250] He added

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[2247] 4 Tr 3401.
[2248] 4 Tr 3401-3402; see Table JRD-2 at 4 Tr 3383. ABATE's proposal would result in total 2027 authorized investments of $190 million, including $52.5 million for SRR, $15 million for Breaker Replacement, $15 million for URD Replacement, $25 million for System Cable, and $82.5 million for Distribution Automation. 4 Tr 3402-3403.
[2249] 4 Tr 3403.
[2250] 4 Tr 3402. This PFD previously addressed Mr. Fitzhenry's testimony.

that the Commission will need to adjust the IRM surcharge to reflect the level of IRM investments, if any, it authorizes for 2026 through 2029.[2251]

CEO Witness Volkmann testified that in Case No. U-21534, the Commission directed DTE to provide more detail and support for its subtransmission projects, including the development of a BCA for projects over $10 million.[2252] He testified that the Company has not yet developed that BCA, quoting DTE witness Stowe's testimony that the Company plans to implement a BCA before its next rate case.[2253] He recommended that the Commission decline to include SRR in the IRM until the Company develops a BCA and can identify those projects with customer benefits exceeding costs.[2254]

Mr. Volkmann next addressed the IRM reconciliation process, testifying that

> the IRM reconciliation process provides visibility into the ***efficiency*** of DTE's IRM investments (i.e., how many units of work the Company achieved with the authorized spending amounts vs. the Company's plan), but not the ***effectiveness*** of the IRM investments (i.e., whether or not the Company is realizing its expected safety and reliability improvement outcomes from the authorized spending).[2255]

He expressed concern that if IRM investment levels are approved through 2029, that spending would be "locked in" regardless of spending effectiveness.[2256] Mr. Volkmann suggested that the reconciliation process could be used to monitor IRM effectiveness and "adjust future IRM authorized spending based on the effectiveness of different programs," explaining,

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[2251] 4 Tr 3402.
[2252] 4 Tr 3665. This PFD previously addressed additional recommendations by Mr. Volkmann concerning DTE's distribution investments.
[2253] 4 Tr 3666.
[2254] 4 Tr 3666.
[2255] 4 Tr 3669, emphasis in original.
[2256] 4 Tr 3669.

> For example, if DTE projects a 25% SAIDI reduction from its PTMM program and it achieves a reduction between 90-100% of that value, IRM spending remains unchanged (or put another way, this confirms the accuracy of the BCA). However, if the PTMM spending in the given time period only results in 75% of the total projected SAIDI reduction, the Commission could order the future IRM spending totals to be reduced (or for the Company to re-run its BCA based on a more accurate estimate of potential savings).[2257]

He recommended that in rebuttal testimony, the Company should propose modifications to the IRM planning and reconciliation process to provide increased transparency and accountability for both the efficiency and effectiveness of its IRM investments.[2258]

Walmart witness Lyon expressed concern that recovery mechanisms such as the IRM "can expand beyond their original intent and usefulness through a utility's efforts to continuously extend and broaden the scope of such mechanisms, as is the case here."[2259] Mr. Lyon recommended that if the Commission approves extending the IRM, it should require DTE to file a rate case "at the earliest possible date when the assets can be included in the Company's test year."[2260] He recommended that the Commission deny the Company's request to expand the 2026 IRM beyond what was approved in the last rate case and require the recovery of additional costs through base rates instead.[2261] He further opined that the Commission should direct the Company to "move away from recovering revenue through an ongoing IRM," and if the Commission approves extension of the IRM, "it should evaluate whether increasing the scope to include ever-increasing costs through a rider is necessary to ensure reliability, or if such costs should be

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[2257] 4 Tr 3670.
[2258] 4 Tr 3671.
[2259] 5 Tr 4097.
[2260] 5 Tr 4097.
[2261] 5 Tr 4097.

recovered through base rates as historically done to consider all costs, benefits, and risks comprehensively."[2262]

In rebuttal, Mr. Willis testified that the Company supported Staff's recommendation to include $200 million of 2026 PTMM investment in the IRM instead of base rates.[2263] Regarding Ms. Shi's proposed disallowance to 2026 Distribution Automation expenditures, Mr. Willis testified that the IRM would effectively mitigate Staff's concern that the Company may fall short of its planned investments, and he recommended that if the Commission shares that concern, it should include the 2026 Distribution Automation program in the IRM as an alternative to disallowance.[2264]

Mr. Willis testified that the Company supported Staff's proposed investment levels for 2027-2029.[2265] Regarding Staff's contingent support for 2028 and 2029 Distribution Automation investments, Mr. Willis responded that "the Company's filings are consistent with the relevant direction issued by the Commission [in Case No. U-21305], and the Company's next Distribution System Plan will similarly be filed consistent with prior orders."[2266]

Mr. Willis disagreed with Staff's recommendation to apply a lower rate of return to the IRM surcharge. He referred to a discovery response by Staff indicating that beyond Mr. Evans' testimony, no analysis was completed to demonstrate why increasing investment levels should lead to a lower rate of return or to demonstrate the propriety of

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[2262] 5 Tr 4081, 4098.
[2263] 4 Tr 1756.
[2264] 4 Tr 1757. Company witness Rademacher further addresses Ms. Shi's recommendation in his rebuttal testimony. See 3 Tr 903-915.
[2265] 4 Tr 1759. See Table 1 at 4 TR 1760, summarizing Staff's proposed investment levels.
[2266] 4 Tr 1760-1761.

Mr. Evans' proposed range between short-term debt and the Company's standard rate of return.[2267] He also referenced Company witness Lepczyk's assertion that the Company's ability to raise capital for investments is not predicated on whether those investments are recovered initially through base rates, or first through the IRM and then base rates, and he noted Mr. Lepczyk's recommendation that the Company's standard rate of return applicable to all capital investments should be similarly applied to IRM investments.[2268] Mr. Willis further testified:

> In this case, as described in the direct testimony of Company Witness Vangilder, the Company updated the rate of return assumption for future years of the IRM to align it with the Company's overall rate of return, instead of the previously approved weighted cost of permanent capital. Such a change is consistent with the Commission's perspective in the January 23, 2025, Order in Case No. U-21534 which noted that there should not be "a higher rate of return on IRM than the rate of return that would apply to non-IRM investments in its distribution infrastructure". The Company's position in this case brings the IRM rate of return into alignment with "non-IRM investments in its distribution system". Given Witness Evans' support for full ROR when the IRM investments are moved to base rates, consistency would suggest that the full ROR be applied to the IRM as well.[2269]

Mr. Willis testified that adopting Staff's proposal "may cause the Company to reevaluate the role of the IRM" because, as described by Mr. Lepczyk, it would be difficult to finance the investments at a reduced rate of return.[2270]

Mr. Willis disputed MNAG's recommendation to terminate the IRM at the end of 2026 based on Mr. Alvarez's perception that IRM investments are subject to a lesser level of review. He countered that the IRM in fact has "greater transparency and opportunity for stakeholder input" than does a general rate case, including an opportunity to debate

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[2267] 4 Tr 1762, citing Exhibit A-59, Schedule AAA1.
[2268] 4 Tr 1762.
[2269] 4 Tr 1762-1763, footnotes omitted.
[2270] 4 Tr 1763.

the prudence of investments in rate cases, to review and provide feedback on project line-item plans before the investments are made, and to participate in a contested reconciliation proceeding.[2271] Mr. Willis also noted DTE's proposal to expand opportunity for input through its enhanced stakeholder engagement process.[2272] He dismissed Mr. Alvarez's "philosophical opposition to rider cost recovery," noting that Mr. Alvarez provided similar testimony in Case No. U-21534 and stating that the Commission appropriately declined to adopt Mr. Alvarez's recommendations in both Case Nos. U-21534 and U-21297.[2273] Mr. Willis further recommended that the Commission reject Mr. Stephens' proposed disallowances to Distribution Automation, PTMM, and SRR (as addressed in detail by the Company's capital program witnesses and discussed above)[2274], and he testified that at a minimum the Commission should adopt Staff's proposed IRM investments levels for 2026 through 2029.[2275]

Next, addressing ABATE's concerns, Mr. Willis testified that the Commission has found the IRM appropriate in multiple cases and has not adopted the view that it constitutes single-issue ratemaking.[2276] He added, "Moreover, the IRM is proposed, litigated, and approved in a contested general rate case such as the instant case—there is no single issue ratemaking."[2277] Mr. Willis disagreed with the notion that the IRM results in expansion of distribution investments, stating that the IRM is one form of cost recovery

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[2271] 4 Tr 1766.
[2272] 4 Tr 1766.
[2273] 4 Tr 1767.
[2274] Mr. Rademacher provided rebuttal testimony addressing issues involving Distribution Automation, Mr. Robinson addressed PTMM, and Mr. Stowe addressed SRR. Mr. Stowe's rebuttal testimony is further discussed below, while the testimonies of Mr. Rademacher and Mr. Robinson were previously addressed in this PFD.
[2275] 4 Tr 1767.
[2276] 4 Tr 1769.
[2277] 4 Tr 1769.

and does not "drive the Company's need to invest."[2278] Regarding Mr. Dauphinais' assertion that the alternative option for 2026 is a re-litigation of the outcome of Case No. U-21534, Mr. Willis responded that the Liberty Audit—which addressed the importance of the PTMM program and provides new information to support inclusion of PTMM in the IRM—was not yet concluded during the last rate case.[2279]

Mr. Willis disagreed with CEO witness Volkmann's recommendation that the IRM reconciliation process be used to monitor investment performance, testifying that the IRM "is a recovery mechanism of otherwise prudent investments" and the "prudence of the programs, including their effectiveness, is an important topic for the Distribution System Plan and is discussed by the Company's distribution capital witnesses in this case."[2280] He further posited that Mr. Volkmann's proposal would constitute retroactive ratemaking:

> Consistent with the concept that the IRM is a recovery mechanism and not itself an investment plan, any needed investments would otherwise be proposed through another recovery mechanism (e.g. base rates). If the Commission approves capital for recovery in rate base, and assuming the investment is made at the approved amount and timing, there is no basis for the Commission to retroactively adjust rate base because the "effectiveness" of the investment was insufficient. Effectiveness tests guide investment decisions; it would be inappropriate and improper to use them to alter prior investment recovery.[2281]

Mr. Willis added that the Company's overall distribution investment strategy is aligned with the recommendations of the Liberty Audit.[2282] And he testified that the Company's pending proposal in Case No. U-21909, regarding financial incentives and disincentives for reliability performance, is a more effective approach to ensuring successful

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[2278] 4 Tr 1769.
[2279] 4 Tr 1769.
[2280] 4 Tr 1771.
[2281] 4 Tr 1771-1772.
[2282] 4 Tr 1772.

investments as it "requires performance across the totality of the Company's investments and reliability efforts"; he opined "it is neither reasonable nor necessary to bifurcate the efficacy of just the Company's IRM investments when considering reliability improvements."[2283]

Regarding Mr. Lyon's testimony, Mr. Willis opposed "any recommendation that the Commission require the Company to file a rate case on a specific cadence."[2284] He added, "While I am not an attorney and am not offering a legal opinion, such a recommendation would in any event appear at odds with MCL 460.6a."[2285] Mr. Willis clarified that with respect to the 2026 IRM, the Company's primary proposal is to include investments in base rates in this proceeding, although the Company is not opposed to including a portion or all of that investment in the IRM.[2286] He further testified that both IRM recovery and base-rate recovery have "a role to play in cost recovery" and that the benefits of the IRM provide "a strong basis to continue utilizing the IRM for distribution investments going forward."[2287]

Mr. Lepczyk also rejected Staff's recommendation for a lower rate of return for the IRM and testified that IRM investments are normal long-term utility assets that provide benefits to customers and require the opportunity to earn a commensurate rate of return.[2288] He disagreed with Mr. Evans' analogy to the Company's tree trim regulatory asset:

[2283] 4 Tr 1772.
[2284] 4 Tr 1773.
[2285] 4 Tr 1773.
[2286] 4 Tr 1774.
[2287] 4 Tr 1774.
[2288] 4 Tr 2935.

> This is not an appropriate comparison. Tree trim surge amounts would ordinarily be recognized as O&M and recovered in the year the expense was recognized. Its appearance on the balance sheet is expressly related to the decision to securitize those amounts to mitigate the rate impact and to spread the cost to customers more evenly over the time horizon of the anticipated benefits. In contrast, the Company finances the IRM assets with the same mix of permanent debt and equity capital that it uses to finance rate base investment. The IRM investments will be funded at the onset with long-term debt and equity, in line with the long-term nature of these assets. A rate of return below the actual cost of permanent capital that finances the investments would discourage debt and equity investment, ultimately raising the cost of capital paid by customers.[2289]

He also stated that return on capital declines after the first year as the asset is depreciated, which means "[d]enying the opportunity to earn a rate of return for this first year materially deteriorates the overall return profile of that asset."[2290]

Mr. Lepczyk testified that Staff's proposal could create "misaligned incentives" in pursuit of the goal of improving customer reliability.[2291] He asserted there is precedent for granting higher ROEs to help achieve policy objectives, specifically noting that Michigan has utilized higher ROEs to encourage deployment of renewable energy and that FERC has allowed a higher ROE to incentivize transmission investments.[2292] Mr. Lepczyk concluded: "Lastly, the fact that the Company is investing more now than before is entirely unrelated to the considerations of investors and the Company's actual cost to finance investments."[2293]

Mr. Stowe testified that the SRR program is critical to improving grid reliability and that it is important to continue to allow recovery of these investments through the IRM.[2294]

[2289] 4 Tr 2935-2936.
[2290] 4 Tr 2936.
[2291] 4 Tr 2936.
[2292] 4 Tr 2936.
[2293] 4 Tr 2936.
[2294] 2 Tr 234.

He disagreed with Mr. Evans' recommendation to keep the previously approved 2026 IRM investment levels and to approve investments for 2027-2029 at the alternative proposed levels, asserting that Mr. Evans' support for continuing SRR in the 2027-2029 IRM supports the fact that SRR is appropriate for IRM treatment, and stating that the Company plans to file a plan addressing its SRR program in its next DSP filing in 2026.[2295] Regarding Mr. Volkmann's recommendation to remove SRR from the 2027-2029 IRM for the lack of a BCA, Mr. Stowe responded that the Company has a substantial pipeline of projects to select from to meet the full proposed 2027-2029 investment levels and will conduct benefit-cost analyses following the development of the BCA framework before its next rate case, as directed by the Commission in Case No. U-21297.[2296] Mr. Stowe further testified that the Company provided Mr. Stephens with reasonable information to support its proposed SRR investment levels and that Mr. Stephens' recommendation to exclude those investments from the IRM should therefore be rejected.[2297]

In Mr. Evans' rebuttal testimony, he summarized the IRM recommendations from the various intervenors and responded that the Commission should reject those proposals and instead adopt Staff's adjustments.[2298]

In its initial brief, DTE reiterates its opposition, as presented in rebuttal testimony, to the recommendations of MNAG witnesses Alvarez and Stephens, ABATE witness Dauphinais, CEO witness Volkmann, and Walmart witness Lyon.[2299] Regarding Staff, DTE agrees with the recommendation to add $200 million of PTMM investments to the

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[2295] 2 Tr 236-237.
[2296] 2 Tr 237-238.
[2297] 2 Tr 239-240.
[2298] 5 Tr 5293-5294.
[2299] DTE brief, 70-71, 202-206.

2026 IRM but advocates that increased amounts for SRR and Distribution Automation should also be added.[2300] The Company asks the Commission, on the one hand, to "approve the three-year extension of the IRM for 2027-2029, for recovery of amounts proposed by Staff, with which the Company agrees,"[2301] while also arguing that the Commission should reject Staff's recommendation for the Company's alternative SRR investment levels for 2027-2029 (50% of the Company's primary proposal)[2302].

The Company references Mr. Willis' and Mr. Lepczyk's rebuttal testimony in opposition to Staff's proposed lower rate of return.[2303] DTE further argues that it is entitled to a commensurate rate of return on its investments and asserts that "any proposal to under-recover new distribution investment through demonstrably inadequate returns that are inconsistent with the returns otherwise determined in this proceeding to be reasonable for other Company investments, as a means to penalize past (Commission-approved) investment levels is unlawful and unreasonable—even if for a brief period."[2304] The Company further notes the rule against retroactive ratemaking and states that the proper solution for past distribution investments that could have or should have been higher is to encourage distribution investment.[2305] It argues that "a lower rate of return for IRM investments could adversely impact financing for these projects, leading to the same 'underinvesting' outcome that Staff uses to support its recommendation."[2306]

[2300] DTE brief, 69-70, 201.
[2301] DTE brief, 200, 206.
[2302] DTE brief, 69-70.
[2303] DTE brief, 201-202.
[2304] DTE brief, 201-202.
[2305] DTE brief, 202.
[2306] DTE brief, 202.

Staff's brief lends support for the inclusion of PTMM investments in the IRM, arguing that it is consistent with the recommendations of the Liberty Audit and noting that the Company developed a BCA model in response to those recommendations.[2307] It echoes Mr. Evans' testimony regarding Staff's support for extending the IRM through 2029 and its proposal for a lower rate of return.[2308]

Consistent with Mr. Alvarez's and Mr. Stephens' testimony, MNSC argue against extending or expanding the IRM. They state that DTE ignores the recommendations of the Liberty Audit to reduce spending for some of its Distribution programs (like SRR and Undergrounding) and to reconsider its approach or slow down spending for other programs (like PTMM and Distribution Automation) and instead seeks increased spending approvals.[2309] MNSC discuss the Commission's conclusions regarding the IRM in DTE's last two rate cases and state that DTE has disregarded the Commission's "directives to exercise restraint."[2310] They further aver that DTE refuses to incorporate the conclusions of the audit process into the IRM, as the Commission instructed in Case No. U-21534.[2311]

MNSC argue that the IRM is "bad policy for customers," referencing Mr. Alvarez's discussion of regulatory lag as well as Mr. Dauphinais' arguments for limiting the IRM's duration and funding levels.[2312] They dispute any suggestion that the Commission already rejected Mr. Alvarez's and Mr. Dauphinais' concerns in Case Nos. U-21534 and U-21297,

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[2307] Staff brief, 22-25, 203.
[2308] Staff brief, 202-206.
[2309] MNSC brief, 172. MNSC's brief includes a detailed analysis of their objections to the Company's spending proposals for PTMM (pp. 37-53), SRR (pp. 53-63), and Distribution Automation (pp. 91-114).
[2310] MNSC brief, 170-172.
[2311] MNSC brief, 175.
[2312] MNSC brief, 173-174.

noting Mr. Willis' acknowledgment during cross-examination that the Commission never expressly rejected their positions, and suggesting that the Commission's previous approval of $104 million out of $1.25 billion in new IRM spending requested by DTE should not be considered an implicit rejection of those concerns.[2313]

MNSC further argue there is "no functional process for reviewing the reasonableness and prudence of projects run through the IRM."[2314] Responding to Mr. Willis' defense of the IRM process, MNSC state:

> Mr. Willis agreed on cross that no IRM projects are reviewed for prudence in a rate case. All that is reviewed in the rate case are the huge spending amounts for which DTEE seeks approval and the Company's general testimony boosting the IRM programs. Mr. Willis countered that the IRM programs are reviewed for reasonableness and prudence, but that does not withstand scrutiny, either. When asked if the Commission's rejection of DTEE's requests to include 4.8kV conversions and PTMM in the IRM in U-21534 meant that the Commission found those programs to be unreasonable and imprudent, Mr. Willis pivoted and said the Commission only determined that they were not prudent to include in the IRM mechanism.[2315]

They also describe the IRM plan review process as "meaningless" and argue:

> Mr. Willis said DTEE filed the 2024 IRM plan in Case No. U-21297 but cross established that it was not filed there. Nor does DTEE publish the IRM plan anywhere on its extensive website. Nor is the plan on the MPSC's website. Apparently, DTEE prepared an amended IRM plan for 2024 that changed the original plan, but that was long after the stakeholder meeting and the amended plan was not published anywhere, either.
>
> The plan itself contains summary information – certainly nothing that can be evaluated for prudence, need, or benefit-cost. Nothing requires DTEE to propose its highest-ranking or highest-scoring projects in the IRM plan. At the meeting, DTEE reads a slide presentation about the summary plan to the attendees and invites questions. With one exception ever, no one provides feedback. Query why anyone would bother providing feedback, since DTEE believes it is under no obligation to accept any feedback or

[2313] MNSC brief, 174-175.
[2314] MNSC brief, 170.
[2315] MNSC brief, 175-176, footnotes omitted.

> agree to any requests for changes, and has in fact never made any changes in response to feedback.[2316]

MNSC conclude it is "inconceivable" that the IRM process will be an effective way of evaluating billions of dollars of spending for which DTE seeks over the next four years.[2317]

Finally, MNSC recommend that if the Commission decides to extend or expand the IRM, the Commission should adopt a lower rate of return on IRM expenditures, consistent with Staff's proposal.[2318] According to MNSC, it is "not apparent" that DTE followed the Commission's direction in Case No. U-21534 to "present in its next rate case justification for the rate of return applied to amounts approved for IRM treatment."[2319]

In her initial brief, the Attorney General adopts Mr. Alvarez's and Mr. Stephens' recommendations against expanding or extending the IRM, and she agrees with MNSC's related arguments presented in briefing.[2320]

ABATE's brief follows Mr. Dauphinais analysis in recommending against expansion of the 2026 IRM or extension of the IRM beyond 2027, and further proposing that 2027 IRM investments be limited to DTE's alternative amounts but with the elimination of PTMM.[2321] It argues that projecting potential costs too far into the future results in speculative forecasted investment amounts, eliminates the ability to consider expense reductions or revenue increases that could impact reasonable or prudent recovery amounts, and "therefore cedes the Commission's obligation to ensure rates are

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[2316] MNSC brief, 176-177, footnotes omitted.
[2317] MNSC brief, 177.
[2318] MNSC brief, 178.
[2319] MNSC brief, 178, quoting January 23, 2025 order in Case No. U-21534, pp. 302-303.
[2320] Attorney General Revised brief, 143-155.
[2321] ABATE brief, 58-63.

just and reasonable, and that utility costs are adequately demonstrated."[2322] ABATE repeats Mr. Dauphinais' concern that DTE's proposal would result in astronomical growth of the Company's distribution investments regardless of need or cost effectiveness.[2323] It also evaluates DTE's proposed Distribution Automation and PTMM investments and recommends that, if the Commission declines to adopt ABATE's primary recommendation, the Commission should at least reduce IRM funding for those two programs consistent with Mr. Dauphinais' and Mr. Fitzhenry's testimony.[2324]

The CEO argue that the Commission should reject IRM spending for PTMM, Distribution Automation, and SRR until the Company conducts further analyses on the propriety of its proposed spending levels.[2325] They recognize the benefits of the IRM as articulated by the Company, but as proposed by Mr. Volkmann, recommend that DTE be required "to include an 'effectiveness' review in future IRM reconciliation cases that benchmarks the actual reliability performance of the Company's investments against the projected reliability performance."[2326] The CEO respond to Mr. Willis' claims in rebuttal that an effectiveness review is unnecessary and would constitute retroactive ratemaking:

> The Company misconstrues the nature of Witness Volkmann's suggestion. DTE is asking for *prospective* authority to spend on projects to be completed four years from now. Such a proposal carries inherent risk for ratepayers. While the Commission could reasonably determine those investments are prudent today, facts on the ground may change necessitating an adjustment in future years. Creating a reconciliation process which reviews the effectiveness of DTE's investments and adjusts future spending preserves the Commission's authority and ensures that customers receive the benefits that exceed the costs of these investments.[2327]

[2322] ABATE brief, 60-61.
[2323] ABATE brief, 61.
[2324] ABATE brief, 20-24, 63.
[2325] CEO brief, 11-25, 48-49.
[2326] CEO brief, 27, 49.
[2327] CEO brief, 29.

Walmart's brief echoes Mr. Lyon's concerns about the potential for continuous expansion of the IRM; recommends against expanding or extending the IRM; and proposes that if the Commission approves DTE's request, it should require the Company to initiate a rate case at the earliest possible date when assets can be included in the test year.[2328]

DTE's reply brief repeats the arguments presented in the Company's initial brief, with two exceptions.[2329] First, the Company disagrees with any suggestion by MNSC that it has a heightened requirement to justify the rate of return for IRM assets, stating that in Case No U-21534 the Commission addressed a potential circumstance where the Company sought a higher rate of return for IRM assets, unlike the present situation where the Company seeks the same rate of return as for non-IRM rate base.[2330] Second, the Company rebuts MNSC's criticism of the IRM process, noting that neither the AG nor MNSC has provided feedback or proposed changes to the Company's IRM plans in the context of the IRM plan review and forum processes, and stating that with respect to the reconciliation process, the Company does not contest the use of a benefit cost analysis per se.[2331]

In her reply brief, the Attorney General objects to the use of IRMs as "thwart[ing] the regulatory balance," stresses the importance of regulatory lag as an effective cost-

[2328] Walmart brief, 7-11.
[2329] See DTE reply, 187-196.
[2330] DTE reply, 191.
[2331] DTE reply, 192-194.

control measure, and agrees with MNSC that the IRM plan and reconciliation processes are insufficient.[2332]

The CEO disagree with the Company's contention that IRM effectiveness is best addressed in the financial incentives docket, arguing that the financial incentives docket "takes a more holistic approach to the Company's reliability performance that lacks the granularity of the IRM reconciliation process" and that the "IRM reconciliation process already exists and is at issue in *this* proceeding."[2333]

ABATE's reply brief relies on arguments already presented,[2334] while none of the other parties address this issue in reply briefing.

This PFD finds, consistent with the Commission's prior determinations, that the IRM serves the purpose of ensuring that critical investments in the Company's distribution system are made but that a cautious, gradual approach is necessary to avoid inefficient spending and excessive costs for ratepayers. Balancing those considerations, this PFD recommends that the Commission approve a one-year extension of the IRM to 2027, with funding levels limited to DTE's alternative proposed programs and amounts, modified as discussed below. Such a measured approach is supported by the fact that the Company has made progress in incorporating the recommendations of the Liberty Audit but still needs to perform further analyses of its SRR and Distribution Automation programs, as noted by Staff witness Evans, MNAG witness Stephens, and CEO witness Volkmann, and acknowledged by the Company.[2335] In addition, the IRM was only first approved in

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[2332] Attorney General reply, 63-65.
[2333] CEO reply, 10, emphasis in original.
[2334] See ABATE reply, 22-24.
[2335] 2 Tr 236-238; 4 Tr 1760-1761, 3666; 5 Tr 4504-4505, 5286, 5288.

late 2023 and the first reconciliation case remains pending. A slower pace forward will allow time to ensure that the reconciliation process is working efficiently as intended and to further scrutinize whether customers are receiving adequate benefit from IRM investments.

As discussed in detail above, both the SRR and DA programs raised significant concerns about both the level and effectiveness of proposed spending, such that these programs require more oversight and scrutiny by the Commission. As such, this PFD recommends that these programs remain in base rates in the test year, with the potential that they may be moved to the IRM in the future. In addition,

To summarize, consistent with capital expenditure recommendations made earlier, this PFD recommends the following IRM investment levels:

Program	**2026**	**2027**
Breaker Replacement	$12.6 million	$15 million
SRR	$53.8 million	0
URD Replacement	$13.5 million	$15 million
Small Wires	$10 million	$10 million
Distribution Automation	$24.4 million	0
PTMM	$197.4 million	$200 million
Total	$311.7 million	$240 million

This PFD agrees with concerns voiced by several intervenors that expansion and extension of the IRM could lead to inefficient spending if investment levels are locked in years before those investments are made. Indeed, while it is clear that substantial overall future investments will be necessary to improve the reliability and safety of DTE's

distribution system, the exact focus of that spending and apportionment among the various programs within the IRM becomes uncertain when multi-year forecasts are involved and with evolving investment needs as the Company further implements its plan. This PFD finds that modification of the reconciliation process could effectively address these concerns and therefore recommends adoption of the CEO's proposal for inclusion of an "effectiveness review" in future IRM reconciliation cases.[2336] This PFD disagrees with any suggestion that adjusting or shifting funding in *future* IRM years, *prospectively*, would implicate retroactive ratemaking.[2337] DTE continually seeks pre-approval of hundreds of millions of dollars (and now a billion dollars) in IRM investments extending multiple years into the future. This PFD cautions against granting DTE's requests without adequate flexibility to protect ratepayers by ensuring that investment levels align with changing needs.

While this PFD appreciates Staff's commentary on the Company's history of underinvestment in its distribution system, this PFD does not find that Staff has adequately justified applying a lower rate of return to the IRM surcharge. The IRM serves as a tool to ensure that necessary capital improvements are made and, as the Company argues, a lower rate of return for IRM investments could discourage continued use of the mechanism. This PFD finds that DTE's proposal to apply its standard rate of return to IRM investments is reasonable and is also responsive to the Commission's concerns that

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[2336] See 4 Tr 3669-3670; CEO brief, 29.

[2337] See *In re Mich Consol Gas Co Application*, 293 Mich App 360, 366; 810 NW2d 123 (2011) ("retroactive ratemaking does not occur if only future rates are affected, with no adjustment to previously set rates"); see also *In re Detroit Edison Co. Application*, 296 Mich App 101, 113-114; 817 NW2d 630 (2012) (tracking mechanisms through which future rates are adjusted to take account of actual past expenses do not violate the rule against retroactive ratemaking).

the Company should not be allowed a windfall through a higher rate of return on IRM assets than the rate of return applicable to non-IRM investments.[2338]

This PFD rejects as unnecessary Walmart's recommended directive that the Company file a rate case at the earliest possible date when IRM assets can be included in the Company's test year.

Finally, this PFD recommends approval of the Company's unopposed proposal to enhance the IRM stakeholder engagement process.

B. Pilot Programs

The Commission has formally defined a pilot program as "a limited duration experiment or program to determine the impact of a measure, integrated solution, or new business relationship on one or more outcomes of interest."[2339] The Commission's February 8, 2021 Order in Case No. U-20645 directed that utility projects that meet this definition are to be evaluated using the following criteria: (1) the need for the pilot and its intended goals; (2) the comprehensiveness of the pilot design and evaluation plan; (3) the pilot's costs; (4) the presence of a detailed timeline for implementation; (5) the presence of a detailed stakeholder engagement plan; and (6) the pilot's benefits and public interest justification.[2340] Each of the six criteria has detailed requirements, and the Commission has specified that provision of all the required data does not guarantee funding approval, nor does the failure to provide some data necessarily require rejection of a proposed pilot.[2341]

[2338] See January 23, 2025 order in Case No. U-21534, p. 303.
[2339] Case No. U-20645, February 8, 2021 Order, Exhibit A.
[2340] Case No. U-20645, February 8, 2021 Order, Exhibit A.
[2341] Case No. U-20645, February 8, 2021 Order, Exhibit A.

This PFD notes that DTE's C&I battery pilot is addressed above as part of demand response.

1. Non-Wires Alternative Pilots

Mr. Rademacher explained that NWAs are projects that use distribution solutions like distributed energy resources (DER), energy waste reduction (EWR), demand response (DR) and grid controls to defer or replace the need for distribution system upgrades.[2342] He provided details and updates regarding the Company's various NWA pilot projects.[2343]

Mr. Kenworthy testified that DTE framed NWA pilots as exploratory, and he supported the projects but was concerned that the Company's approach was limited and fragmented rather than systematic.[2344] He opined that the pilots would merely be "isolated demonstrations" without a methodology for identifying where grid needs exist, quantifying avoided distribution system investments, and incorporating avoided costs into future procurement decisions. Mr. Kenworthy testified that without a systematic approach DTE could not move beyond one-off projects that could not scale to create enduring value for ratepayers. To address this issue, he recommended that the Commission direct the Company to develop a methodology to identify grid needs and assign a value to avoided or deferred distribution investments.[2345] He asserted that this methodology should then be applied in evaluating DER solutions, including NWAs, virtual power plants, and other

[2342] 3 Tr 788.
[2343] See 3 Tr 789-799; see also Exhibit A-12 Schedules B5.4.1-B5.4.7 (NWA pilot information).
[2344] 4 Tr 3614.
[2345] 4 Tr 3615.

load flexibility initiatives, so that DER can compete on a level playing field with traditional infrastructure.[2346]

In rebuttal, Mr. Rademacher stated that Mr. Kenworthy's testimony on NWAs ignores "the value of DTE's approach" because the pilots are designed to facilitate broader planning and future customer-facing programs and do not restrict future implementation.[2347] He explained that investments in visibility, control, and system intelligence are not the end goal but rather "are the essential enablers for all future customer-facing, load flexibility, and NWA programs."[2348]

The Company's briefing does not specifically address this issue. In its briefing, the CEO states that it has advocated for a more comprehensive approach to NWA programs in several rate cases without significant movement from the Company.[2349] The CEO states that the Commission can ensure that DTE further develops NWA projects beyond the pilot phase by adopting Mr. Kenworthy's recommendation.[2350]

This PFD finds that the CEO recommendation has merit; however, issues concerning implementation and evaluation of programs like NWA are more appropriately addressed as part of DTE's grid planning.

2. Strategic Undergrounding Pilots

Mr. Stowe testified that the Company is developing two new undergrounding pilot projects: the Attica project to test undergrounding in a rural area and the Spruce project

[2346] 4 Tr 3615.
[2347] 3 Tr 944-945.
[2348] 3 Tr 945.
[2349] CEO brief, 37.
[2350] CEO brief, 38.

to test undergrounding in a suburban neighborhood.[2351] He testified that DTE worked with 1898 & Co to conduct a BCA for these projects and that the BCA of the Attica project scored 1.51, demonstrating that the benefits of the project exceed the costs, while the score for Spruce was 0.69, indicating the converse.[2352]

For the suburban Spruce project, Mr. Stowe explained that the city of Ann Arbor planned to replace the roads within the affected subdivision, which provided DTE with a "unique synergy opportunity" because the Company could avoid costs associated with road reconstruction.[2353] For the Attica project, he explained that it would enhance the Company's understanding of the strategic challenges that face undergrounding projects in rural areas.[2354] Mr. Stowe testified that undergrounding distribution assets brings unique benefits and resilience to weather-related outages, and the lessons learned from these projects would be used to refine the BCA model to help identify segments of overhead infrastructure that are good candidates for future undergrounding.[2355]

On behalf of ABATE, Mr. Fitzhenry did not object to the Attica undergrounding pilot, but he opposed the Spruce project, which had a benefit/cost ratio of 0.69 and was therefore not a cost-effective investment for ratepayers.[2356] He opined that DTE should wait to identify a suburban location to test undergrounding that will produce benefits that

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[2351] 2 Tr 160.
[2352] 2 Tr 160. He specified that the BCA analysis was performed by witness De Stigter, and that witness's relevant testimony can be found at 4 Tr 1858. See also Confidential Exhibits A-28 Schedules R4 and R5 for additional information about these projects.
[2353] 2 Tr 160-161.
[2354] 2 Tr 161.
[2355] 2 Tr 164.
[2356] 4 Tr 3369.

exceed the costs. Mr. Fitzhenry thus recommended that $11.6 million in test year capital expenditures associated with this pilot should be disallowed.[2357]

MNAG witness Stephens opined that the company's previous Appoline and Bufalo-Charles undergrounding projects—with per-customer costs of $14,672 and $37,908 respectively—already demonstrated that undergrounding overhead lines is not cost effective.[2358] Mr. Stephens also cited a Lawrence Berkeley National Laboratory (LBNL) report that examined the Texas grid to further support his claim that undergrounding is not cost effective and should not be pursued.[2359] Mr. Stephens provided a hypothetical scenario to illustrate that undergrounding any significant portion of DTE's customer base would be cost prohibitive based upon the Company's Appoline and Buffalo-Charles projects such that no additional pilots are warranted.[2360] He therefore recommended that the Commission disallow the $14 million associated with undergrounding pilots.[2361]

In rebuttal, Mr. Stowe asserted that Mr. Stephens did not draw the proper conclusion from the LBNL report that he cited because the report evaluated the cost effectiveness (or lack thereof) of undergrounding the distribution and transmission systems in the entire state of Texas.[2362] Mr. Stowe stated that the report found that targeting specific areas of the grid for undergrounding could be cost effective, and that such a targeted approached aligned with the Commission's previous direction to review

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[2357] 4 Tr 3370.
[2358] 5 Tr 4541.
[2359] 5 Tr 4541 (citing Larsen P., *A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines*. Lawrence Berkeley National Laboratory report LBNL-1006394).
[2360] 5 Tr 4542.
[2361] 5 Tr 4542.
[2362] 4 Tr 231.

targeted undergrounding projects.[2363] Mr. Stowe agreed that undergrounding infrastructure was costly, but he explained that these pilots have helped the Company improve processes, explore cost-saving partnerships, and prepare for broader implementation in a more efficient and strategic way.[2364] Overall, Mr. Stowe rejected the call to disallow all funds for undergrounding pilots because of the benefits undergrounding provides and because the projects would provide the Company with the opportunity to refine its process and implementation of undergrounding projects.

Mr. Stowe specifically disagreed with Mr. Fitzhenry's recommendation to disallow funding for the Spruce project based upon its benefit/cost ratio.[2365] He cited the city of Ann Arbor's plan to replace roads in the area as a "synergy" for the project and opined that, despite the BCA, the project was a "unique opportunity to learn from municipal infrastructure coordination with strategic undergrounding in an area that the company was already going to rebuild as part of the ISO Conversion Program."[2366]

In briefing, DTE rejects the proposed disallowances stating that the Commission has directed the Company to investigate strategic undergrounding for targeted areas and to develop a business case for undergrounding.[2367] DTE states that the undergrounding pilot projects in this case offer an opportunity to understand potential cost efficiencies that could be achieved by working synergistically with municipalities.[2368] Accordingly, the Company contends that the disallowances should be rejected.

[2363] 2 Tr 231.
[2364] 2 Tr 231.
[2365] 2 Tr 233.
[2366] 2 Tr 233.
[2367] Consumers brief, 68-69.
[2368] Consumers brief, 69.

ABATE's brief argues that costs for the Spruce project should be disallowed because the company's own BCA shows far greater costs than benefits.[2369] ABATE opines that regardless of DTE's claims regarding synergy with preplanned municipal road construction, it is nevertheless unreasonable to ask ratepayers to bear the costs when those costs greatly eclipse the potential benefits.[2370] ABATE argues that if the Company wishes to testing undergrounding in a suburban environment, then it "should do so at its own cost or wait to identify a project in which benefits exceed costs."[2371]

The Attorney General's brief requests a full $14 million disallowance and repeats points derived from the testimony of Mr. Stephens to conclude that the Company failed to meet its burden of proof to justify the undergrounding pilots given their high costs.[2372]

MNSC's initial brief adopts the same position as the Attorney General and relies on the testimony of Mr. Stephens to recommend rejecting the undergrounding pilots.[2373]

The Company's reply acknowledges opposition to its undergrounding pilots but states that Mr. Stowe adequately rebutted concerns about the projects raised by the Attorney General and MNSC.[2374] In its reply, ABATE repeats the arguments stated in its initial brief.[2375] MNSC's reply provides no further argument, while the Attorney General's reply brief repeats the request to "adopt AG-MN witness Stephens's recommendation to disallow $14 million in the test year for strategic undergrounding pilots."[2376]

[2369] ABATE brief, 24.
[2370] ABATE brief, 24.
[2371] ABATE brief, 25.
[2372] Attorney General brief, 175-177.
[2373] MNSC brief, 87-90.
[2374] DTE reply, 36.
[2375] ABATE reply, 8-9.
[2376] Attorney General reply, 26.

This PFD agrees with ABATE that capital expenditures associated with Spruce project ($11.6 million) should be disallowed because that project's BCA indicates that its costs meaningfully exceed the benefits it will produce. This PFD declines to adopt the Attorney General's recommendation to disallow all funds associated with undergrounding pilots because the Commission has directed the Company to investigate targeted, strategic undergrounding projects where there is a business case to do so. The Company's Attica project, with a favorable benefit/cost ratio, appears to be such a project such that a disallowance is not warranted.

3. Residential Home Generator Pilot

Mr. Leuker described DTE's previously-approved residential home generator pilot which uses telemetry to remotely activate select customer's home generators during DR events.[2377] He stated that there are 176 customers enrolled in the pilot, which called a total of four DR events.[2378] Mr. Leuker related the results of the program and stated that, based upon the positive results, the Company planned to continue the pilot before expanding it into a full program.[2379]

Ann Arbor witness Lange criticized the pilot home generator program because of its use of home generators that burn natural gas, which produces carbon dioxide and harmful emissions.[2380] He stated that he did not support a program that shifted electric load to fossil fuel generators, but he could support a DR program based upon battery storage charged by renewables.[2381] Mr. Lange recommended disallowing the $532,000

[2377] 3 Tr 1359.
[2378] 3 Tr 1361, 1362.
[2379] 3 Tr 1362.
[2380] 4 Tr 3709.
[2381] 4 Tr 3711.

requested for the pilot asserting that it was not reasonable to fund a pilot that promotes harmful emissions in populated areas while excluding non-emitting alternatives like batteries.[2382]

In rebuttal, Mr. Leuker stated that the Company's partner in the program, Generac, unexpectedly terminated support for the program in the first quarter of 2025 such that DTE had to unenroll all pilot participants.[2383] Mr. Leuker suggested that Mr. Lange's recommendation to disallow $532,000 in O&M for the pilot was unnecessary as the Company was no longer seeking O&M expenses related to the now defunct pilot program.[2384] However, Mr. Leuker asked that the Commission "recognize the opportunity that exists within this space and to allow the Company to revisit the pilot, or make the pilot a program, in the future and receive the appropriate funding when requested."[2385]

The Company's brief provided no further meaningful information on this pilot program. However, in its brief, Ann Arbor acknowledged that company witness Leuker stated that $532,000 O&M expense for this pilot is no longer needed and recommended disallowing the cost.[2386] Ann Arbor also further elaborated on its objections to this pilot stating that it is unreasonable and imprudent to explore DR programs that do not align with climate change or clean energy goals.[2387]

DTE's reply reiterates that the home generator pilot is closed such that O&M funding is no longer requested; however, the Company repeats its request to recognize

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[2382] 4 Tr 3712.
[2383] 3 Tr 1384.
[2384] 3 Tr 1385.
[2385] 3 Tr 1386.
[2386] Ann Arbor brief, 15.
[2387] Ann Arbor brief, 15-17.

that opportunity exists to revisit a similar pilot program concept in the future.[2388] Ann Arbor's reply provides no further argument on this topic.

This PFD recommends adopting the O&M disallowance of $532,000 recommended by Ann Arbor because, as the Company has explained, this pilot program was involuntarily terminated such that funding is no longer required. This PFD further agrees with Ann Arbor that if DTE wishes to pursue a similar pilot in the future, it should consider the Company's own clean energy goals, and consider a battery or solar plus battery approach, as Ann Arbor suggests.

C. Affordability

Mr. Bruzzano and Mr. Sparks provided testimony concerning the impact of DTE's rate increase on residential customers and the Company's efforts to help low-income customers maintain access to electric service and afford their energy bills. Intervenors CUB-NRDC (Mr. Bunch), CEO (Mr. Boratha) and the DAAO (Ms. Nichols, Ms. Watts, Mr. Kinkhabwala, Ms. Jacob, and Mr. Schott) provided extensive testimony on (1) affordability and energy burdens; (2) low-income energy assistance programs; (3) unregulated programs; and (4) shutoffs. These issues and related disputes are discussed below.

1. Energy Burden and Affordability

Mr. Bruzzano testified that DTE's requested rate increase would increase the average residential customer's electric bill by 44 cents per day, which in turn would result in an average yearly bill increase, since 2021, of 2.6%. He maintained that this increase is below the rate of inflation and below the average increases experienced by other

[2388] DTE reply, 77.

utilities in the Great Lakes region and at the national level.[2389] He added that according to Energy Information Administration (EIA) data, DTE's average residential customer bill was 14.5% below the national average in 2024.[2390]

Mr. Bunch testified that the reason electricity bills are lower in Michigan than in many other states is because Michigan households are more likely to use fuels, not electricity, for space and water heating. He asserted that the most useful comparison is total energy burden, which looks at all energy expenditures, allowing for a better apples-to-apples comparison across geographies with differing mixes of electricity, gas and other household energy sources. According to Mr. Bunch, in 2022, Michigan ranked 14th worst nationally for total residential energy burden.[2391] He stated that "the Company's historical and geographic comparisons of total electric bills fail to make the case for its proposed rate increase" and the reality is "that overall residential energy burden in Michigan remains high."[2392]

Ms. Nichols testified that the Commission's definition of affordability from Case No. U-20757 recognizes that affordability is not just about the monthly cost of energy, but also about the ability of households to pay for utility services while still meeting other essential needs like food, housing, healthcare, and transportation; and it emphasizes the importance of energy efficiency and sustainability in promoting long-term affordability and energy equity.[2393]

[2389] 3 Tr 975-976, Figure 1.
[2390] 3 Tr 976-977, Figure 2.
[2391] 5 Tr 4828.
[2392] 5 Tr 4829.
[2393] 5 Tr 4111.

She noted that the percentage of gross income a household spends on energy is considered its "energy burden" and an energy burden of less than 6% is considered affordable. However, she stated, in 2022, Michigan households at or below 50% of the Federal Poverty Level (FPL) faced an average energy burden of 38%, while those between 50% and 100% FPL had an average energy burden of 20%.[2394]

She testified that DTE's rate request increases customer bills by at least $13 per month, or $156 per year, which would be a significant financial burden for already struggling families. And she asserted, low-income customers will likely see even bigger rate impacts because of poor insulation, less energy efficient appliances, and decreased access to smart technology.[2395] She testified that DAAO analyzed the extent to which DTE's proposed rate increase would increase energy burdens in 2025 and 2026 for Wayne County households at or below 80% Area Median Income (AMI). She asserted that the analysis found that the rate hike would: (1) push at least three census tracts with average energy burdens currently below 6% to the brink of unaffordability; (2) drive currently affordable energy burdens in eight additional census tracks into unaffordability (above the 6% threshold); and (3) propel the number of census tracts with severely unaffordable energy burdens of 10% or more from 24 to 42.[2396]

Ms. Watts asserted that the Company's last rate increase has caused "everyone," not just people on fixed incomes, to struggle and "it does not make sense" to raise rates again so soon.[2397] Ms. Watts testified that her home, like many homes in DTE's service

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[2394] 5 Tr 4111-4112.
[2395] 5 Tr 4112-4113.
[2396] 5 Tr 4113.kj5yu67478
[2397] 5 Tr 4167.

area, is very poorly insulated, so she wastes a lot of energy heating and cooling her home.[2398] She stated that because rates are so high, she limits her use of air conditioning as much as possible but, because she has asthma, her ability to avoid air conditioning is limited. She testified that she is "scared" she "will have to choose between paying the bills and her physical health and she testified that many in her community share her concerns.[2399]

Mr. Kinkhabwala testified that DTE's requested rate increase disproportionately affects residential customers. He noted that DTE is requesting to raise residential rates by 11.1%, commercial rates by 10.8%, and industrial rates by only 5.4%.[2400] According to him, DTE's assertion that its residential electric bills are about 15% less than the national average is flawed since DTE customers generally do not use electricity for heating and they have less cooling needs than the rest of the nation.[2401] He maintained that comparisons of average electric rates, rather than electric bills, removes these flaws and shows that DTE consistently has residential rates higher than the 75th percentile of peer investor-owned utilities across the nation.[2402]

Mr. Kinkhabwala used a regression model developed by PSE Healthy Energy, which includes data from the EIA and the U.S. Census Bureau, to generate what he called "the most fine-grained estimates of household energy bills and affordability metrics to date."[2403] He classified households that rely on electricity for heating as cost burdened if

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[2398] 5 tr 4168.
[2399] 5 Tr 4169.
[2400] 5 Tr 4204.
[2401] 5 Tr 4205, Figure 1.
[2402] 5 Tr 4206-4207, Figure 2.
[2403] 5 Tr 4208-4209.

they spend more than 6% of their income on electricity, and those that use natural gas or other fossil fuels for heat as cost burdened if they spend more than 4% of their income on electricity.[2404] According to Mr. Kinkhabwala "nearly every household less than 150% of the federal poverty level is energy cost burdened," while even above this threshold and up to 3 times the FPL "many households are still energy cost burdened."[2405]

Mr. Kinkhabwala asserted that there are geographical and racial disparities in the energy affordability gap.[2406] He noted that affordability challenges are prevalent throughout the entire DTE territory but in the Detroit area there are many predominantly Black neighborhoods where the affordability gap is very high, which is driven by combinations of income inequality and racial segregation.[2407] He continued that a disproportionate amount of energy affordability issues are found in Environmental Justice (EJ) communities as identified by the MIEJ Screening Tool, which shows roughly 42% of all cost-burdened customers in DTE's service area live in EJ communities, which is home to only 24% of the population.[2408]

Mr. Kinkhabwala testified that the public comments in this case highlight the concerns DTE customers have about the affordability of their electric bills.[2409] He recommended that DTE's residential rate increases be limited to substantially less than 11.1% to avoid "outsized negative impacts" and If the Company increases its residential rates, it should explain how it will avoid an ensuing increase in power shutoffs.[2410] He also

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[2404] 5 Tr 4209.
[2405] 5 Tr 4216, Figure 3.
[2406] 5 Tr 4210.
[2407] 5 Tr 4219.
[2408] 5 Tr 4220-4221, Table 2.
[2409] 5 Tr 4221-4222.
[2410] 5 Tr 4248-4249.

stated that increased data regarding arrearage, shutoffs, and bill assistance should be made available and presented with sufficient granularity, such as different FPL tiers, zip code, or census tract.[2411]

Ms. Jacob opined that electricity must be treated as a "human right," but to an increasing number of low- and middle-income customers in DTE's service territory it is becoming an inaccessible and unreliable "privilege."[2412] She opined that DTE customers are facing an "unprecedented affordability crisis" that must be met with swift and immediate action that prioritizes the needs of customers, especially low-income customers, rather than increasing profits for shareholders.[2413]

She testified that 43% of Black households (183,997 households) and 38% of Hispanic households (20,976) in metro Detroit experience a high energy burden of more than 6% and the median energy burden of low-income households in Detroit is 3.7 times greater than non-low-income households. She claimed that some of her lowest-income clients have an energy burden of 30%, which is "a grossly inequitable energy burden that threatens residents' ability to stay in their homes, pay for basic necessities like food and healthcare, maintain a household budget, and invest in their families and communities."[2414]

Mr. Schott testified that the 2024 median electric burden for DTE customers with income less than 200% FPL is estimated to be 6.92%, which is 5.7 times higher than the median electric burden of 1.22% for non-low-income customers. He estimated that

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[2411] 5 Tr 4249.
[2412] 5 Tr 4261-4262.
[2413] 5 Tr 4262.
[2414] 5 Tr 4266.

485,743 DTE customers had an unaffordable electric burden (above 3.6%). He maintained that this translates to an estimated 86.05% of DTE's low-income customers having unaffordable electric burdens compared to only 3.47% of non-low-income customers.[2415] He indicated that there is a strong positive correlation between the median electric burden within a census tract and the percent of its customers classified as low income, as well as a correlation between Black, Indigenous, and people of color (BIPOC) census tracts.[2416]

Mr. Schott referred to DTE's comparison of its residential bills relative to the national average as its key indicator of affordability and contended that it "misses the mark" in several ways, including that whether a bill is affordable or not is experienced by individual households, not an average of the entire service area. He asserted that comparing average customer bills does not account for more expensive heating costs in Michigan's colder climate and fails to incorporate the relative cost to customers of meeting their other essential needs.[2417]

According to Mr. Schott, DTE did not offer a specific estimate of the impact of rate increases on low-income bills, but he noted that Mr. Bruzzano indicated that the Company's proposed 11.1% residential rate increase is "a mere 44 cents per day."[2418] Mr. Schott used DTE's data, but with only a 40 cent per day increase, to estimate the average low-income customer bill in 2026. Then he added reasonable charges for late fees, reconnection fees, taxes, or unregulated programs, to estimate the "real cost" for

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[2415] 5 Tr 4352-4353, Figure 1.
[2416] 5 Tr 4353-4356, Figures 2-4.
[2417] 5 Tr 4371-4372,
[2418] 5 Tr 4368.

low-income households in 2026 as between $1,728 and $1,880, with the midpoint being $1,804.[2419] He maintained that if low-income customers' consumption mirrors 2024 at 7,365 kWh per year, they will pay a total "all-in" cost per kWh of 24 cents, which he opined is starkly different than what DTE has presented. He added that for a $1,804 annual electric bill to be affordable (at a 3.6% burden), a customer must have a gross income that exceeds $50,166, which he stated, means that "DTE is proposing to make electricity unaffordable for 693,340 (33.9%) customers who are below that income level."[2420]

Mr. Schott was also critical of the Commission's Energy Affordability and Assistance Collaborative (EAAC) and requested "a remedy from the Commission based on the evidence of the EAAC's performance."[2421] He asserted that the Commission has positioned the EAAC as the primary channel for managing affordability and energy security matters through its orders in previous cases, however the EAAC has functioned primarily as a gatekeeper and "stymied measurable progress."[2422] He testified that the EAAC has focused extensively on definitions and wordsmithing, has failed to establish metrics for tracking energy affordability and security, and continues to resist straightforward recommendations and Commission directives. He opined that DTE's low-income customers, especially in Black and Brown communities, are suffering because of the EAAC's inaction (and DTE's ambivalence).[2423] He proposed that the Commission

[2419] 5 Tr 4368-4369.
[2420] 5 Tr 4369.
[2421] 5 Tr 4390.
[2422] 5 Tr 4389-4390.
[2423] 5 Tr 4394.

make determinations on the evidentiary proposals it receives in the instant case and not defer them to the EAAC.[2424]

In briefing, DTE reiterates its witnesses' testimony that its requested rate increase would leave average residential rates below the average increases experienced at other utilities in the Great Lakes region and at the national level.[2425]

Staff's brief did not address affordability concerns generally but addressed Energy Assistance Program reform and residential shutoff protections.

In its brief, the DAAO argues that under the "just and reasonable standard," the Commission must consider affordability and if, despite the extensive evidence of "the affordability crisis," it does not, then the Commission is violating the Michigan Administrative Procedure Act (APA) and the Michigan Constitution.[2426] According to the DAAO, in determining whether a rate is "just and reasonable," Michigan courts require the Commission to examine both "cost" and "value of service to the consumer."[2427] The DAAO asserts that when examining the cost of a rate, the Commission must consider its impact on affordability and affordability significantly impacts the "value of service to the consumer."[2428] The DAAO contend that its witnesses have submitted substantial evidence that there is an affordability crisis, which would be exacerbated by DTE's proposed rate increase, and failing to consider this would render the Commission's decision arbitrary and capricious.[2429] Further argues the DAAO, the Commission could

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[2424] 5 Tr 4399.
[2425] DTE brief, 5.
[2426] DAAO brief, 43.
[2427] DAAO brief, 44.
[2428] DAAO brief, 45-47.
[2429] DAAO brief, 50.

not possibly make a "reasoned opinion" that it would be "just and reasonable" to allow DTE's electric rates to increase based on the record in this case.[2430] DAAO states that it is neither just nor reasonable to require households to take on additional debt, sacrifice other necessary household expenses, or incur additional healthcare costs to afford their energy bills, which are what an 11.1% residential rate increase would result in.[2431] Lastly, the DAAO argues, it is unacceptable for the Commission to raise rates "while punting" affordability issues to the EAAC.[2432] According to the DAAO, it is the Commission's duty and obligation to consider affordability when setting rates and it cannot pass affordability concerns to a body that has demonstrated an inability to adequately address those concerns.[2433]

In its brief, the MNSC also refers to the "just and reasonable" standard and points out that the Commission must balance investor and consumer interests, and consumer interests should include affordability considerations.[2434]

In its reply brief, DTE argues that DAAO's framing of the law is "inapposite" and "overstates" the legal requirements in this case. DTE contends that there is ample evidence on the record that it has adequately considered and made efforts in the area of affordability.[2435] DTE posits that DAAO's affordability analysis is overly reductive and the fact that customers are facing cost increases across a variety of cost categories is an insufficient basis for the Commission to conclude that DTE's proposed rates are

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[2430] DAAO brief, 51.
[2431] DAAO brief, 53.
[2432] DAAO brief, 43.
[2433]DAAO brief, 56-58.
[2434] MNSC brief, 2.
[2435] DTE reply, 224.

unaffordable.[2436] The Company also expresses support for the EAAC and current efforts by it, the Company, the Commission, and the State to support customers facing hardship.[2437]

Staff's reply notes that "there is no state or federal, constitutional statutory guarantee for free or fixed rate utility services for those that cannot afford to pay" and a rate case is not the correct docket to discuss these matters.[2438] Staff refers to the Energy Affordability Report drafted by the EAAC and observes that the DAAO has not commented on the Report's recommendations.[2439] Staff points to the Report's recommendation that "rates cannot be held at a zero increase without balancing the interests of customers on the whole against the interest of the utility" and submits that this is the legal standard to which the Company is held.[2440]

In its reply, the DAAO argues that Staff barely considers affordability when it "wrongly recommends" that the Commission approve a rate increase for DTE.[2441] The DAAO contend that Staff consistently defers affordability issues to the EAAC and other workgroups and the Energy Affordability Report referred to by Staff is insufficient on its own to address the worsening affordability crisis in DTE's service territory.[2442] The DAAO argue that if the Commission does not address affordability, it cannot approve DTE's rate increase.[2443]

[2436] DTE reply, 224-225.
[2437] DTE reply, 225.
[2438] Staff reply, 18.
[2439] Staff reply, 20.
[2440] Staff reply, 20-21.
[2441] DAAO reply, 6-8.
[2442] DAAO reply, 6.
[2443] DAAO reply, 8.

This PFD finds that the intervenors have provided extensive and compelling evidence that DTE's low-income customers, particularly those in BIPOC communities, face unaffordable electric burdens, that is that their electric bills constitute more than 4% or 6% of their household income, depending on whether they use electricity for heating. This PFD also agrees with the intervenors that DTE's proposed 11.1% rate increase would cause a greater number of customers to face unaffordable electric bills and push those already facing unaffordable electric bills into a more dire situation. However, this PFD agrees with Staff that the Commission must follow statutory and other legal directives when setting rates and while this PFD agrees with DAAO's contention that the Commission must consider affordability, it declines to adopt DAAO's recommendation that DTE's residential rate increase be denied.

This PFD also finds that DTE's comparison of its average residential bills to the average of electric bills across the nation or in the Great Lakes region does not consider that Michigan households are more likely to use fuels for heating or how DTE's electric bills impact the ability of its customers to afford other basic needs. This PFD agrees with CUB-NRDC and the DAAO that energy burden is a better and more useful comparison. Accordingly, this PFD recommends that in all rate cases going forward DTE present data about its residential rates and the impact of its requested rate increases on residential customers by providing data on the electricity burdens of its residential customers.

Turning to DAAO's request that the Commission not defer decisions on affordability to the EAAC, this PFD notes that generally, the Commission has expressed its preference that discussions on affordability, low-income assistance programs, and shutoffs occur in collaborative workgroups, such as the EAAC. However it is also noted

that in DTE's last rate case, Case No. U-21534, the Commission stated that, "[C]ustomers who are currently experiencing difficulty in affording utility bills and other necessities need more immediate relief than can be provided by waiting for the final decisions from the EAAC."[2444] This PFD finds that Staff's Energy Affordability Report, submitted to the Commission on September 10, 2025, addresses the concerns about affordability and the need for immediate relief, as it includes a recommended timeline for clear Commission guidance by February 2026 with implementation of specific recommendations by October 1, 2026. This PFD recommends that the Commission adopt this timeline.

Finally, this PFD acknowledges the DAAO's comments that the impact of rate increases on low-income customers are generally intensified by poor insulation, less energy efficient appliances and decreased access to smart technology. Therefore, this PFD recommends that DTE be directed to implement an initiative to educate all low-income customers about, and assist them with, accessing programs or funding for weatherization, EWR, and energy efficiency.

2. Low-Income Assistance Programs

Mr. Sparks testified that DTE's energy assistance programs are designed around the Commissions definition of "affordability," in Case No. U-20757 which states that affordability is:

> . . . the extent to which a household has the resources to meet their home energy needs for heating, cooling, and other uses in a healthy, sustainable, and energy-efficient manner without compromising their ability to meet other basic needs.[2445]

[2444] January 23, 2025 order in Case No. U-21534, p. 405.
[2445] 4 Tr 2714-2715; December 21, 2023 order in Case No. U-20757, p. 36.

He testified that the Company's energy assistance programs were designed to achieve several key objectives, including sustained energy access, arrears reduction, payment habit encouragement, consumption reduction, short-term assistance, empowerment and self-sufficiency, and community collaboration.[2446]

Mr. Sparks detailed DTE's efforts to ensure its customers are aware of and can access its energy assistance programs and apply for State funding. The efforts noted by Mr. Sparks include Customer Resource Fairs, Community Pop-ups, Community Outreach, Senior Community Outreach, Internal Training Outreach, as well as web resources, automated calls, email blasts, letter campaigns, and brochures in multiple languages.[2447]

According to Mr. Sparks, DTE's low-income offerings include the Low-Income Self Sufficiency Program (LSP), Residential Income Assistance (RIA) credits, and Low-Income Assistance (LIA) credits.[2448] He described the LSP as a 2-year payment plan for families at or below 150% FPL that provides affordable monthly payments based on income and energy usage. According to Mr. Sparks, DTE made several changes to the LSP to align it with other utilities' affordable payment plans as directed by the Commission.[2449] Mr. Sparks further explained that the Company's RIA and LIA credits are based on statute and eligibility is defined in MCL 460.10t6(b) as customers with income at or below 150% of the FPL or who receive assistance from a state emergency relief program, food stamps, or Medicaid.[2450] He stated that the RIA credit is a per month

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[2446] 4 Tr 2716.
[2447] 4 Tr 2719-2722.
[2448] 4 Tr 2717.
[2449] 4 Tr 2723.
[2450] 4 Tr 2726.

credit that is equivalent to the electric service charge, while the LIA credit is $50 per month.[2451]

Mr. Sparks testified that DTE also offered a Payment Stability Plan (PSP) as a pilot in 2022 to 2024.[2452] He explained that the pilot was a percentage of income-based program (PIPP) directed at low-income customers at or below 200% of FPL that focused on affordable energy burdens. Customers who received either gas or electric service from DTE had a flat bill payment equivalent to 6% of their household gross income, while customers who received both gas and electric had a payment equivalent to 10% of their household gross income.[2453]

Ms. Nichols maintained that DTE's LSP, LIA, and RIA programs are insufficient to mitigate the impact of rate increases for low-income customers. She explained that there are several issues with LSP's payment structure that prevent the program from reliably delivering affordable energy burdens. For instance, she asserted that LSP's 150% FPL cap fails to recognize that Michigan households between 150% and 200% FPL still face average energy burdens that exceed the income affordability threshold of 6%.[2454] She remarked that the RIA and LIA fail to make up for LSP's deficiencies. She asserted that the $8.50 monthly RIA bill credit does not even cover the Company's proposed rate increase, let alone significantly reduce energy burdens. And while the LIA provides a more sizable $50 bill credit, enrollment is much more limited; eligible customers who are not also enrolled in LSP can only receive the LIA credit "when there is availability" and "at

[2451] 4 Tr 2727, 2730.
[2452] 4 Tr 2717.
[2453] 4 Tr 2725.
[2454] 5 Tr 4114-4115.

the Company's discretion."[2455] Ms. Nichols testified that data showing increased customer arrears and shutoff notices demonstrates that DTE's assistance efforts have not been sufficient and, "unless the Commission directs DTE to take a new course of action to address affordability, shutoffs and arrears balances will only further increase as the Company seeks its fifth rate increase in the past six years."[2456]

To improve affordability, Ms. Nichols testified that the Commission should require that DTE immediately implement a PIPP program for low-income customers. According to Ms. Nichols, DTE's final report on the PSP pilot noted that PIPP programs more directly address the challenges faced by low-income households and the report recommended reallocating both the RIA and the LSP funds into a relaunched PSP program.[2457] She agreed with this but offered several modifications to the relaunched PSP.

First, she asserted that DTE's 6% of income payment cap for single-utility service is too high and unaffordable. She noted that several of the existing PIPP programs in the other states that DTE studied before implementing the PSP pilot have payment caps below 6%, including California, Pennsylvania, and Ohio. She determined that "ideally, payments for single-utility electric service should be capped at no greater than 4%."[2458]

Second, she asserted that DTE's $1,500 arrears cap for PSP eligibility is too restrictive and risks excluding customers from the program who are in the direst need of both payment assistance and arrears forgiveness. She opposed any cap on arrears for

[2455] 5 Tr 4115.
[2456] 4 Tr 4116.
[2457] 5 Tr 4116-4118.
[2458] 5 Tr 4119.

eligibility, however, if there must be an arrears cap, she stated that it should at the very least be no less than LSP's former cap of $3,000.[2459]

Lastly, she testified that it is both unnecessary and overly burdensome to require annual income recertification to maintain enrollment in PSP. She noted that California only requires customers to recertify assistance eligibility every two years, or four years if they are on a fixed income. She recommended that the Commission consider requiring a similar term for a relaunched PSP program.[2460]

Ms. Watts remarked that LSP participants should be able to afford their bills and avoid shutoffs; however, even when enrolled, some customers get their energy shutoff because their bills are still too high. She testified that approximately 18% and 19% of LSP participants in 2021 and 2022, respectively, experienced a shutoff within 12 months of enrolling.[2461] Ms. Watts also testified that contrary to DTE's claims that it actively seeks to inform customers about its low-income programs, her experience has been that DTE does a poor job of communicating with customers directly about its various assistance programs. She recommended that the Commission require DTE to enroll people in PIPP automatically and share information about its assistance programs clearly, openly, and frequently.[2462]

Mr. Kinkhabwala testified that at DTE's current residential electric rates, $310 million in bill assistance is needed per year to keep electric bills affordable. He asserted that this would increase to $395 million if DTE's requested 11.1% residential rate increase

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[2459] 5 Tr 4219-4240.
[2460] 5 Tr 4120.
[2461] 5 Tr 4173.
[2462] 5 Tr 4175

is implemented. He opined that this is a staggering increase of 27%. He estimated the full energy affordability gap at $510 million currently, which rises to $605 million after the proposed 11.1% increase.[2463] He noted that DTE's reported 2024 energy assistance expenditures for all its programs were only $144 million, which he asserted is at most roughly 28% percent of the estimated $510 million needed in 2025.[2464]

He examined the impact pf DTE's requested rate increase using the PSP pilot's affordability thresholds and 150% FPL limit. He testified that under the 11.1% increase, 40,000 additional customers would be eligible for the program and necessitate a 31% increase in funding.[2465] However, under DTE's PIPP proposals, a little more than one out of eight eligible customers could receive benefits.[2466] He noted for example that there are 240,000 households that spend greater than 6% of their income on energy but would not qualify for the proposed PIPP program after the 11.1% increase. He opined that this shift onto other burdened households could be minimized if commercial and industrial customers also contributed meaningfully to the PIPP program.[2467]

Ms. Jacob opined that DTE fundamentally misunderstands the challenges faced by low- to moderate-income customers. She cited DTE witness Sparks' testimony, including his statements that "DTE Electric's initiatives are designed to promote responsible payment behaviors among participants," and "these [payment] programs assist customers in establishing a habit of regular bill payments." She emphasized that her clients and so many other low- to moderate-income customers across Michigan do

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[2463] 5 Tr 4212-4213, Table 1.
[2464] 5 Tr 4215.
[2465] 5 Tr 4212.
[2466] 5 Tr 4213.
[2467] 5 Tr 4213-4214.

everything that they can to stay on top of their bills and make consistent payments for their electricity usage and they neither misunderstand their responsibility nor lack responsible payment behavior.[2468]

She described the assistance programs available to DTE electric customers experiencing payment difficulties and stated that in her perspective, they fall far short of meeting the needs of low-income customers.[2469] There is not enough funding available in existing programs to address the full depth of need for those enrolled in the programs and the programs are so restricted that they do not capture the full breadth of need throughout DTE's service territory.[2470] Additionally, she stated that she receives dozens of calls from DTE customers who are confused and unable to access DTE's assistance programs. She noted that many of her clients have not completed high school, lack access to the internet, and are not digitally literate, and several have limited English proficiency.[2471]

Ms. Jacob was concerned about the proposed modifications to the LSP program.[2472] She explained that DTE performed little proactive outreach to inform current LSP enrollees about the modifications, which increase monthly payments by as much as $100, eliminate the freezing of arrears, and provide delayed forgiveness.[2473] She acknowledged that it is a positive step that the modified LSP does not contain an arrears cap, but she maintained that the structure of arrears forgiveness payments still creates challenges for program participants.[2474]

[2468] 5 Tr 4268-4269.
[2469] 5 Tr 4270-4290.
[2470] 5 Tr 4290.
[2471] 5 Tr 4292.
[2472] 5 Tr 4308.
[2473] 5 Tr 4303-4307.
[2474] 5 Tr 4303-4304.

Ms. Jacob recommended that all low- to moderate-income customers be transitioned immediately to a PIPP that provides meaningful levels of support or in the alternative, the Commission require the Company to immediately improve its modified LSP and gather and use additional information using focus groups, surveys, and interviews, that capture the impact of the transition to the modified LSP on the customers currently enrolled in the program.[2475]

Mr. Schott testified that DTE is not using the Commission-adopted definition of affordability in its analysis of its low-income programs, contrary to the Commission's order in U-21534, which stated:

> [T]he Commission expects DTE Electric to use the Commission-adopted definition of 'affordability' for any analyses it presents to the Commission when referencing affordability impacts of energy-assistance programs in contested cases.[2476]

Referring to Mr. Sparks' testimony that DTE's foremost objective is to ensure that customers, particularly those with low incomes, have continued access to essential energy services, Mr. Schott asserted there is little evidence of progress toward this stated goal.[2477] Mr. Schott posited that DTE does not invest sufficient efforts to enroll eligible customers in its assistance programs. He noted that according to Mr. Sparks, DTE cut $1.1 million in outreach, including for low-income customer programs, in order to "mitigate the financial challenges experienced by the Company in 2023." According to Mr. Schott, DTE's net income increased 29.0% to $1.40 billion in 2023, which demonstrates a lack of good faith.[2478]

[2475] 5 Tr 4321-4322.
[2476] 5 Tr 4371; January 23, 2025 order in Case No. U-21534, p. 461.
[2477] 5 Tr 4373-4374.
[2478] 5 Tr 4375.

Mr. Schott testified that the LSP program should be replaced with a PIPP, like the PSP pilot. He stated that low-income customers enrolled in DTE's PSP pilot reduced their electric consumption by 9.1% and gas consumption by 11.3%, compared to LSP enrollees who's electric and gas consumption increased 3.4% and 3.1%, respectively.[2479] He asserted that this should dispel any concerns about the rebound effect of low-income customers taking advantage of an affordability program.[2480] Mr. Schott noted that in Case No. U-20929, DTE is proposing to reallocate LIA, RIA, and LSP funds to a PSP program costing approximately $60 to $74 million.[2481] He "wholeheartedly supported" a well-designed, well-run PIPP and made several recommended changes to DTE's PSP: (1) the benefit should cap electric-only burdens at 3.6% of income and combination electric and gas burdens at 6% of income; (2) DTE should maximize the allocation of arrearage forgiveness, EWR, and favorable rate and DER program benefits; (3) the program budget would ideally be sufficient to serve all eligible and interested customers; and (4) a third-party administrator may be needed to overcome issues with outreach, mistrust, and resulting low enrollment rates.[2482]

He asserted that the costs to run a PIPP as he recommends are significantly higher than DTE is proposing for the future of its PSP, but he asserted that DTE's proposed costs are low because DTE's PSP is still pegged to an unaffordable 10% overall energy burden and DTE's count of the number of low-income customers is still only based on the number who enroll in low-income programs, rather than the census tract data of its service

[2479] 5 Tr 4414-4415, Figure 22.
[2480] 5 Tr 4415.
[2481] 5 Tr 4416.
[2482] 5 Tr 4416-4417.

territory. He estimated that 432,224 customers are low-income and have an average electric affordability gap–the amount they spend above 3.6% of income–of $736 per household and the cost to eliminate these affordability gaps for all customers would be $318,137,245 (not counting any administrative costs).[2483]

Mr. Schott stressed that a PIPP is an appropriate means to benefit households across DTE's entire service territory, but an additional program is needed to "get at the deep structural roots of energy poverty among communities that have been heavily impacted by multiple pressures on energy insecurity."[2484] Accordingly, Mr. Schott proposed a new Community-Wide Affordability Program (CWAP) that would not be based on specific customer incomes but would grant all residents in a census tract a standard credit that would reduce the median electric burden of the census tract to an affordable electric burden of 3.6% and an affordable gas burden of 2.4%.[2485] He asserted that this model could easily be adapted to accommodate additional, census tract resolution datasets, such as shutoffs, arrears, and participants in assistance and EWR programs.[2486] He noted that the Minnesota Public Utilities Commission approved a similar approach by Xcel Energy in 2024 called the automatic bill credit pilot, calling it a "novel and potentially effective method" for lowering the energy burden for Xcel's low-income customers, which "recognizes that poverty is often concentrated in certain areas."[2487]

He acknowledged that the average benefit under a CWAP would be about 21% higher than the combination of the LIA credit ($50/month) and the RIA credit

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[2483] 5 Tr 4417.
[2484] 5 Tr 4433.
[2485] 5 Tr 4418; Exhibit DAO-404.
[2486] 5 Tr 4418-4419.
[2487] 5 Tr 4419-4420.

($8.50/month), but asserted there would be multiple benefits, such as reduced administrative burdens for the Company and for participating households.[2488] Mr. Schott described the proposed CWAP in detail.[2489] He noted that it could be designed to work with different budgets and that it would offset the cost of a PIPP.[2490]

Mr. Schott testified that when considering the costs of any affordability program, the Commission should consider the net value of the program, or the revenue requirement minus direct financial benefits, as well as the offsets, such as reduced operating expenses, more equitable distribution of program costs among all rate classes, and ratepayer savings from reduced corporate expenses, including ROE reductions.[2491] He suggested that as a cost control measure to other ratepayers, the Commission should assess the net cost of his proposed affordability and shutoff protection measures. He identified $215.1 million in potential cost offsets that could be used to fund affordability programs, such as a PIPP expansion or the CWAP.[2492]

Mr. Sparks testified in rebuttal that DTE recognizes that income-based models, like PIPPs and like the PSP, can offer meaningful support to low-income customers. However, he did not address any of the specific recommendations made by the DAAO witnesses, stating that it is important to wait for the conclusion of the EAAC's collaborative work and the Commission's review on a statewide PIPP. He emphasized that DTE "remains

[2488] 5 Tr 4422.
[2489] 5 Tr 4427-4430.
[2490] 5 Tr 4431-4433.
[2491] 5 Tr 4433-4434.
[2492] 5 Tr 4435-4436, Figure 26.

committed to supporting customers through existing affordability programs and continues to engage actively in the EAAC process."[2493]

In rebuttal, Staff witness Braunschweig cited the following authorities: MCL 460.11(2), which provides that in its rate case filings, "a utility shall include proposed eligible low-income customer and eligible senior citizen customer rates and a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes"; MCL 460.10t(6)(b), which defines eligible low-income customer to include households with income at or less than 150% of the FPL; and the Commission's order addressing the LIA credit in Case No. U-21534.[2494]

According to Ms. Braunschweig, in Consumers' most recent electric rate case, Case No. U-21585, the Commission reaffirmed that utility rate cases are not the appropriate forum for large-scale energy assistance reform, deferring the issue to other forums, such as the EAAC and EWR plan proceedings.[2495] She noted that Staff's Energy Affordability Report, filed on September 10, 2025, addressed many of the topics discussed by the DAAO witnesses. She testified that Staff recommends that the Commission take a consistent approach and align its decisions with the Energy Affordability Report as it addresses the intervenor recommendations in this case.[2496]

In briefing, DTE reiterates that it is focused on assisting its low-income customers and advocates for continuation of the LIA credits.[2497]

[2493] 4 Tr 2746-2747.
[2494] 5 Tr 5227-5228.
[2495] 5 Tr 5228.
[2496] 5 Tr 5228-5229.
[2497] DTE brief, 5-6.

Staff's brief highlights Ms. Braunschweig's reference to MCL 460.11(2) and states that it is important to keep this statute in mind when considering proposals like Mr. Schott's CWAP.[2498]

In its brief, the DAAO asserts that the Commission cannot fully consider affordability by only examining DTE's current low-income assistance programs since these programs are not available to many struggling customers due to various eligibility requirements. And posits the DAAO, only considering DTE's current programs does not satisfy the just-and-reasonable requirement as it does not represent a "balancing" of "consumer interests."[2499]

DTE's reply brief concurs with Staff that considerations regarding energy assistance funding and related programs should be addressed as part of the Commission's response to the Energy Affordability Report and that the Commission should align its decisions in this case with that report.[2500]

Staff's reply argues that assistance programs should be considered within the context of the Commission's definition of affordability, which acknowledges both the needs of the Company and its customers.[2501]

In its reply, DAAO argues that DTE's current assistance programs are already failing to meet the needs of its struggling customers and that neither the Company or Staff

[2498] Staff brief, 219.
[2499] DAAO brief, 49.
[2500] DTE reply, 219-220.
[2501] Staff reply, 14-15.

offer any recommendations to address these failings.[2502] The DAAO restate that the Commission should order DTE to adopt a full PIPP and a CWAP.[2503]

This PFD shares DAAO's concerns that DTE's current low-income assistance programs do not provide aid to all the customers that are struggling with unaffordable electric bills, and those that are being helped are not receiving sufficient assistance to make their electric bills affordable. However, this PFD appreciates Staff's recognition that low-income assistance programs must be designed in accordance with MCL 460.11(2) and the definition of an eligible low-income customer (households with income at or less than 150% of the FPL) in MCL 460.10t(6)(b). This PFD also finds that the EAAC and the resulting Energy Affordability Report provide an appropriate consideration of the complexity of the low-income assistance landscape, including cost of service formulas and other statutory mandates, program eligibility, funding sources and availability, PIPPs versus Affordable Payment Plans (APPs), customer outreach, and rate impacts for all customers. Further, the Energy Affordability Report makes specific recommendations for a redesigned energy assistance system with energy assistance subsidies based on an overall energy burden of 6% and an electric burden of 4%.[2504]

Based on the foregoing, in response to the intervenors' many specific recommendations, and in agreement with Staff, this PFD recommends that the Commission review the Energy Affordability Report and adopt its specific recommendations to redesign the energy assistance system and provide guidance by

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[2502] DAAO reply, 7-8.
[2503] DAAO reply, 2, 9-10.
[2504] Staff's Energy Affordability Report, September 10, 2025, p. 162, 171.

February 2026 such that a redesigned energy assistance landscape would be implemented by October 1, 2026. This PFD acknowledges that it appears that DAAO did not participate in the EAAC and therefore the collaboration did not consider the need or feasibility of a CWAP or the net costs of energy assistance and affordability programs and therefore recommends that the EAAC review these matters and provide a report with recommendations by October 1, 2026. This PFD also recommends that the DAAO participate in the EAAC despite its reservations. This PFD also recommends that the Commission direct DTE to use electric burden as its key indicator of affordability in its analysis of its low-income programs.

3. Unregulated Programs

Ms. Jacob asserted that many DTE customers are confused by the difference between affordability programs and optional non-energy programs, or unregulated programs, such as the Surge Protection and TreeGuard programs.[2505] She maintained that many customers believe these programs provide affordability assistance and/or they misunderstand the programs and felt compelled to enroll in them after speaking with a DTE customer service representative.[2506] She noted that some clients had been enrolled in these programs for years without understanding what they were being charged for, and, consequently, as their service bills rose and forced them to fall behind on payments, they also accumulated unpaid non-energy fees, deepening their existing DTE arrears.[2507] She asserted that additional efforts by DTE are needed to inform customers of what these

[2505] 5 Tr 4292.
[2506] 5 Tr 4293.
[2507] 5 Tr 4294.

non-energy programs provide and what enrolling in them means for their monthly bills and DTE must make it easier for customers to disenroll.[2508]

Mr. Schott also expressed concerns about TreeGuard Assurance and Surge Protection, as well as DTE's Home Protection Plus (HPP) and GreenBacks Cash programs, stating that they dramatically increase customer bills and that DTE is being granted a competitive advantage over other businesses.[2509] Acknowledging that Commission rules prohibit unregulated programs from directly resulting in a shutoff, he questioned how DTE can separate out the costs of these programs from past due balances when the Company states that it does not track how much a customer owes for unregulated programs or services.[2510]

He testified that there is a disproportionately high participation in unregulated programs among residents of Wayne County: while Oakland, Macomb and Washtenaw Counties have a combined population of about 2.5 million vs. Wayne County's 1.75 million, their participation in the Surge Protection Program is 62% lower than Wayne County's (5,659 vs. 14,838). He stated that participation rates and disparities are similar in the TreeGuard program.[2511]

Mr. Schott presented data on the profitability of DTE's TreeGuard Assurance and Surge Protection programs and opined that DTE's residential unregulated programs are generally very profitable.[2512] But he noted that DTE offers other less profitable programs, which he said appear to benefit higher income residential customers or commercial and

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[2508] 5 Tr 4294-4295.
[2509] 5 Tr 4384.
[2510] 5 Tr 4385-4386.
[2511] 5 Tr 4386.
[2512] 5 Tr 4386-4387, Figure 17.

industrial customers. He opined that the Company "subsidizes these programs while setting the costs of programs that disproportionately enroll lower-income and majority BIPOC communities to rake in substantial profits."[2513] He made several recommendations to the Commission regarding unregulated programs. First, he testified that the Commission should thoroughly investigate these programs to include revenues, profits, impacts on affordability and shutoffs, and disparities in marketing and enrollment. Second, the Commission should require DTE to separate these program services and bills from standard DTE bills for gas and electricity. Third, he recommended that the Commission evaluate the terms of these programs and consider requiring (or recommending) changes that enable customers to cancel without penalty and clarify what coverage does and does not provide.[2514] Fourth, he suggested that DTE should be required to inform customers in arrears and facing shutoffs that they are participating in a voluntary program(s) and can terminate their participation at no cost at any time.[2515] Fifth, he stated that DTE should reduce marketing of the HPP programs. And finally, DTE should report annually on the number of participants in each unregulated program, by census tract, revenue collected, and benefits paid out.[2516]

In briefing, the DAAO notes that the Commission cannot regulate these programs but has authority to "look into how these additional charges intersect with affordability and affordability programs."[2517]

[2513] 5 Tr 4387.
[2514] 5 Tr 4388.
[2515] 5 Tr 4388-4389.
[2516] 5 Tr 4389.
[2517] DAAO brief, 28.

This PFD notes that other than the DAAO, no other party presented evidence or commented on DTE's unregulated programs. This PFD finds that based on the evidence presented by the DAAO that there are likely many low-income customers that are enrolled in DTE's unregulated programs that do not need them and cannot afford them. This PFD recommends that the EAAC be tasked with investigating the impact of DTE's unregulated programs on affordability and shutoffs, to include disparities in marketing and enrollment, and make recommendations to the Commission on ways to mitigate these impacts.

4. Shutoffs

Mr. Bunch testified that "the most vivid consequence" of DTE's rising electricity rates is the growing number of customers remaining disconnected from service, owing to non-payment, at the end of each month.[2518] He asserted that this number is growing even while the number of shutoffs each month remains stable because disconnected customers cannot satisfy the Company's requirements for having their power restored.[2519] Mr. Bunch testified that in 2022-2023, the number of electric customers remaining disconnected consistently averaged 1,783, but by the last quarter of 2024, the average was 4,332. He stated that it "is an ominous sign to see pronounced and sustained growth in these numbers."[2520]

Mr. Bunch testified that the reason fewer customers can satisfy the financial requirements to have their electricity restored might be a high arrears balance. He stated that the average arrears balance has risen alarmingly since late 2023, roughly doubling

[2518] 5 Tr 4829.
[2519] 5 Tr 4829-4831, Figure 1.
[2520] 5 Tr 4830.

over the subsequent 18 months.[2521] Mr. Bunch opined that if DTE's proposed rate increase in this case is approved, the number of customers who remain disconnected each month and the amount of average arrears balance will accelerate even more.[2522] He recommended that the Commission require the Company to investigate and explain this recent trend, and how it proposes to address any underlying problems, as part of its next rate filing.[2523]

Mr. Tan presented the results of a regression analysis using DTE's residential disconnection (shutoff) information aggregated to zip codes and using area median income (AMI) and race or BIPOC as independent variables.[2524] His results indicated that: for a $10,000 increase in AMI, a zip code experiences 134 fewer residential disconnections; a 100% BIPOC zip code experiences, on average, 2499 more residential disconnections than a 0% BIPOC zip code; a 1% increase in BIPOC concentration is associated with an increase of 25 disconnections; holding income constant, a 100% BIPOC zip code experiences, on average, 2348 more residential disconnections than a 0% BIPOC zip code; and holding income constant, a 1% increase in BIPOC concentration is associated with an increase of 23.48 disconnections in a particular zip code.[2525]

Mr. Tan observed that while the regression results show that there is a significant number of disconnections occurring in BIPOC zip codes, the geographic size of zip codes limits how confidently conclusions can be made since a single zip code can contain a number of communities with distinct demographics, including income and race, and there

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[2521] 5 Tr 4831-4832, Figure 2.
[2522] 5 Tr 4832.
[2523] 5 Tr 4833.
[2524] 4 Tr 3696-3697.
[2525] 4 Tr 3697-3698.

is not an equal spread of race in all the zip codes.[2526] He noted that census tract data would do a much better job describing the demographics of a community. Because of this, he recommended that DTE record and maintain its residential disconnection data aggregated to census tracts.[2527] Despite the limitations of zip code data, Mr. Tan stated that the regression results demonstrate a need for analyzing disconnections more closely such that DTE should review its disconnection policies and analyze if customers are disconnected differently based on where they live (such as Wayne County versus Washtenaw County), or the racial makeup or income levels of their neighborhoods.[2528]

Mr. Kinkhabwala testified that DTE's reliability models aim to decrease outage minutes, but they ignore shutoff minutes, which he asserted are another type of outage. Using data for the most recent 12-month period obtained from DTE in discovery, Mr. Kinkhabwala calculated a total of 52 million annual shutoff minutes and he pointed out in comparison that the Company is proposing a $265 million 4.8kV hardening project to avoid 25 million of outage minutes.[2529] He estimated that the potential impact of DTE's proposed rate increase on shutoff minutes is at least an incremental 25 million minutes annually. However, he opined, nowhere in DTE's planning is this increase in shutoffs discussed or considered despite it being on the same scale as the Company's reliability initiatives.[2530]

[2526] 4 Tr 3699-3701, Figure 11-12.
[2527] 4 Tr 3701.
[2528] 4 Tr 3701-3702.
[2529] 5 Tr 4227-4228.
[2530] 5 Tr 4228.

Ms. Jacob testified that there is a lack of awareness of DTE's winter shutoff protection plans, the Senior Winter Protection Plan (WPP) and the Low-Income WPP.[2531]

She also maintained that the Low-Income WPP is generally unaffordable and the cost savings of the program are minimal as compared to the non-income restricted BudgetWise program. She further asserted that it is problematic that customers enrolled in the Low-Income WPP are ineligible for the SER. She opined that the Company must increase its efforts to inform seniors of the Senior WPP, automatically enroll seniors in the plan, and automatically reconnect their service during the heating season.[2532]

As for DTE's Critical Care Protection program and Medical Customer Protection Program, Ms. Jacob testified that they are difficult to access and inadequate. She criticized the requirement that medical certification forms be submitted only after a shutoff notice is received and that even with a medical certification form, DTE can still deny entrance into the programs.[2533] She stated that DTE should defer to its customers and their medical professionals when making determinations for these programs and should also provide more information about the programs to customers and medical professionals.[2534]

Mr. Schott presented data showing that since 2019 DTE has executed 1,032,765 shutoffs and between 2022 and 2024, DTE shut off 8.6%, or one in every twelve of its customers and 80.53% or four in every five of its low-income customers.[2535] According to Mr. Schott, the data also shows that about 20% of households who are shut off are shut

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[2531] 5 Tr 4309-4310.
[2532] 5 Tr 4311.
[2533] 5 Tr 4313, 4316.
[2534] 5 Tr 4314-4317.
[2535] 5 Tr 4357-4359, Figures 5, 6, 7, 8, and 9.

off multiple times, 19% of shutoffs last longer than one day, and nearly 40,000 shutoffs are extended three days or more.[2536] He asserted that extended shutoffs should be as much a cause for concern as when a customer experiences an extended outage from a downed wire.[2537]

Mr. Schott attempted to quantify the financial and health costs of shutoffs, by among other things, estimating losses for food, medicine, and adaptation methods (visits to hotels or warming/cooling centers, or the home repairs due to mold remediation or burst pipes).[2538] He testified that the average cost of a shutoff is $297 and that for 2023, DTE's electric shutoffs caused $56.7 million in non-utility financial losses among impacted customers. He noted that these estimates do not include additional late fees, reconnection fees, or the costs of additional often predatory loans that households take on to pay an additional deposit.[2539]

According to Mr. Schott, wildfire smoke exacerbates the impact of shutoffs. He stated that, "nationally, the public health hazards of wildfire smoke may equal or surpass the hazards of extreme heat by mid-century" and "many of the causes of death caused by wildfires already disproportionately impact communities of color that face elevated risks of diseases like asthma–like Detroit."[2540] He recommended extended seasonal shutoff protection for wildfire smoke that mirrors seasonal protections during the heating season and to protect vulnerable DTE customers, he proposed a blanket seasonal shutoff protection from Memorial Day to Labor Day for all customers, with thresholds (e.g. heat

[2536] 5 Tr 4359-4361, Figure 10.
[2537] 5 Tr 4361.
[2538] 5 Tr 4361-4363, Figure 12.
[2539] 5 Tr 4363.
[2540] 5 Tr 4405-4406.

advisories or air quality alerts) to call additional daily protections based on conditions outside of the prime season.[2541]

Mr. Schott estimated three types of societal costs that result from shutoffs: (1) the value of lost wages and unpaid labor (e.g. caretaking); (2) the value of shortened lifespans over the long term from impacts related to lack of access to energy; and (3) the value of premature deaths that may result directly from a shutoff in the short-term.[2542] He asserted that in addition to the costs to the customer experiencing the shutoff, there are also costs to ratepayers in the form of excessive costs of collections, customer service, and surcharges for affordability programs that do not prevent shutoffs.[2543]

Mr. Schott testified that DTE is not required to shutoff customers who cannot pay their bill and there is no evidence that shutoffs save ratepayers money or lower uncollectibles.[2544] He posited that unfortunately, DTE has a financial incentive to execute shutoffs in the form of late fees and reconnection fees, which are a direct source of shareholder profits. He noted that DTE collected $5.6 million in reconnection fees from 2021-2023 and collects about $15 million annually from late fees.[2545] He asserted that these fees only benefit shareholders, while the Company passes the substantial costs to operate its collections and shutoffs architecture on to ratepayers.[2546] He maintained that DTE compels customers who can pay their bills to subsidize a system in which the Company profits while executing one of the highest, most punitive shutoff rates in the

[2541] 5 Tr 4409.
[2542] 5 Tr 4402-4404, Figure 19.
[2543] 5 Tr 4400-4402.
[2544] 5 Tr 4409-4410.
[2545] 5 Tr 4376-4377.
[2546] 5 Tr 4377.

country.[2547] He stated that, “For a company that budgets $100 million annually for customer service operations, which does not include the budget for assistance programs, I find DTE’s failure to develop and implement a meaningful strategy to mitigate shutoffs egregious.”[2548]

To prevent shutoffs, Mr. Schott recommended that DTE set targets, such as an annual, system-wide target and a low-income target, to reduce shutoffs and measure progress on affordability and energy insecurity; identify customers with incomes below 200% of FPL who are not currently classified as low-income but are eligible for assistance programs; evaluate why the annual shutoff rate of low-income customers exceeds 25%; and quantify the value of reduced shutoffs, in both customer benefits and reduced operating costs.[2549] He also recommended that DTE prioritize EWR programs for the most vulnerable and impacted households, propose additional shutoff protections that expand coverage to customers whose health is endangered by losing power, and align its proposed PIPP to an overall energy burden of 6% of income.[2550]

Mr. Schott opined that shutoffs “are a relic of a time when we didn’t know better, when we thought that cutting people off from a basic human necessity was somehow both necessary and reasonable.”[2551] He asserted that it is incumbent on the Commission to direct DTE and other regulated utilities to replace the practice of shutoffs with alternatives

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[2547] 5 Tr 4377-4378.
[2548] 5 Tr 4383.
[2549] 5 Tr 4381.
[2550] 5 Tr 4381-4382.
[2551] 5 Tr 4413.

that are both humane, deliver major societal benefits, and minimize costs to other ratepayers.[2552] He supported a complete moratorium on shutoffs for non-payment.

If the above recommendation is not adopted Mr. Schott offered the following recommendations: (1) seasonal summer shutoff protections that account for both extreme heat and wildfire smoke; (2) expanded condition-based summer shutoff protections that set a conservative heat index threshold for all utilities accounting for humidity and the duration of a heat wave; (3) blanket shutoff protections for pregnant people and households with children; (4) permanent medical/critical care protections for households with a documented condition that requires uninterrupted access to energy; and (5) shutoff protection for households that have requested participation in an EWR or assistance programs but have been waitlisted or denied because of insufficient availability.[2553]

In rebuttal, Mr. Sparks testified that DTE's disconnection policies are applied uniformly across its service territory and shutoff decisions are based on account status and payment history, not geographic location, race, or income level. He stated that the Company also does not believe that reporting shutoff data at the census tract level is practical or necessary to understand shutoff trends.[2554] He testified further that there are a number of concerns with collecting this level of data, such as the possibility that specific customers could be matched to disconnection information and that it would require new programming and processes since the Company's billing system is not configured to accommodate data at the census tract level.[2555]

[2552] 5 Tr 4419-4411.
[2553] 5 Tr 4411-4412.
[2554] 4 Tr 2743.
[2555] 4 Tr 2743-2744.

In response to Mr. Bunch's suggestion that DTE investigate and explain the increase in the number of customers who remain disconnected each month, Mr. Sparks countered that the disconnect data analyzed by Mr. Bunch refers to premises, not customers, and can reflect a range of circumstances, such as vacancy, seasonal inactivity, or a customer who has relocated, such that drawing conclusions about customer behavior or hardship from the data risks oversimplifying a complex picture.[2556] He added that undertaking such an investigation would require extensive resources to identify and engage with relevant customers.[2557] He maintained that DTE will continue to provide detailed reporting as required under Case No. U-20757, but "any additional directives should be grounded in a clear understanding of the data's scope and limitations and balanced against the practical feasibility and potential impact of the proposed analysis."[2558]

Staff witness Armstrong responded to Mr. Schott's extreme weather shutoff recommendations. She stated that the Commission is addressing extreme weather condition policies in Case No. U-20140, which will include input from interested parties, a technical conference, and a report with recommendations due in February 2026. She suggested that Mr. Schott's recommendations for expanded extreme weather protections could be addressed in this docket.[2559]

As for Mr. Schott's recommendation for a blanket shutoff protection for pregnant people and households with children, Ms. Armstrong indicated that she is not aware of

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[2556] 4 Tr 2744.
[2557] 4 Tr 2744-2745.
[2558] 4 Tr 2745.
[2559] 5 Tr 5313-5314.

any proceeding addressing this issue, but as of 2024, MEAP is mandated to prioritize energy assistance, defined as a program to reduce energy insecurity, to vulnerable populations, which include a low-income household with at least one member that is a child under five years of age.[2560] She also testified that the Commission is addressing shutoff protections for medical and critical care customers in Case No. U-20757 through the work of the Critical Care Collaborative (CCC).[2561]

The Company's initial brief does not comment on shutoffs, while in its brief, the CEO reiterate Mr. Tan's testimony. The CEO emphasize that they are not alleging that DTE is intentionally applying its disconnection policies in a disparate fashion, but that there is a concerning relationship between race and disconnections that merits further investigation.[2562]

In briefing, Staff recommends that all extreme weather conditions and critical care customer policies be addressed in their respective dockets, such as Case No. U-20140 and Case No. U-20757.[2563]

In briefing, MNSC contends that despite DTE's assertions to the contrary, it should not be too difficult for DTE to analyze historical customer account data to determine how many customers whose electricity is shut off for nonpayment have their service restored, the average time it takes for such customers to have their service restored, whether the duration of the average shut-off is increasing, whether and to what extent shut-off duration

[2560] 5 Tr 5314.
[2561] 5 Tr 5315.
[2562] CEO brief, 48.
[2563] Staff brief, 222.

correlates with arrearage balances, and other factors that would shed light on the increasing number of customers remaining shutoff at the end of each month.[2564]

In its brief, the DAAO recommend that the Commission require DTE to improve both its Critical Care Protection Program and its Medical Customer Program to ensure that they align with the goals outlined in Michigan law.[2565] The DAAO assert that DTE's entire service area contains 2.25 million customers, but in 2024, only 298 customers received critical care protections, which is likely significantly less than those who are eligible for the program.[2566] The DAAO argues that recent efforts to revamp the program, such as the CCC, have done little to improve it and the Commission actually made the program more restrictive by imposing additional eligibility requirements for customers who are in arrears.[2567] The DAAO urge the Commission to reevaluate its decisions or at the very least require that DTE publish its internal guidance for eligible conditions, affirmatively reach out to medical providers, and provide fulsome and timely explanations and an appeal process to customers denied entrance into both programs.[2568]

In its reply brief, DTE expresses support for Staff's position that residential shutoff protections, extreme weather conditions and critical care customer policies be developed in their respective dockets and the Company notes that it is actively engaged in these workgroups and subcommittees.[2569]

[2564] MNSC brief, 197.
[2565] DAAO brief, 106.
[2566] DAAO brief, 109-110.
[2567] DAAO brief, 111.
[2568] DAAO brief, 112.
[2569] DTE reply, 220.

In its reply Staff states that "shutoffs are certainly not desired by anyone and are of concern," but a rate case is not the appropriate docket for discussions of shutoff moratoriums, disconnections, or critical care issues.[2570] Staff notes that critical care protection policies should be addressed via the CCC in Case No. U-20757 and that DAAO was invited to the CCC but generally did not bring its concerns or solutions to the table.[2571] Staff argues that the Commission directed utilities to work with medical professionals to address their customers' medical needs and qualifying medical equipment, and Staff expects DTE will follow this directive.[2572]

In its reply, the DAAO argues that Staff's "punting" of shutoff and critical care protections to the extreme weather docket and the CCC does not relieve the Commission of its legal responsibility to consider affordability in this rate case.[2573]

This PFD generally agrees with the intervenors that the data indicates that shutoffs are increasing and that shutoffs impose manifold costs upon impacted customers, ratepayers, and society and that it would be prudent to analyze shutoffs more thoroughly. Accordingly, this PFD recommends that the Commission direct DTE to gather, review, and analyze its customer account data to determine the following: how many customers whose electricity is shut off for nonpayment have their service restored and the average time it takes for restoration; whether the duration of the average shut-off is increasing; whether and to what extent shut-off duration correlates with arrearage balances; and any other factor that may reveal why disconnections are increasing and how to reduce them.

[2570] Staff reply, 16.
[2571] Staff reply, 17.
[2572] Staff reply, 19-20.
[2573] DAAO reply, 7.

Further, DTE should review its disconnection policies and use regression analysis to determine if customers are disconnected disparately based on race, income, or geography and report shutoff data at the census tract level.

As for DAAO's recommendations to improve DTE's medical and critical care protection programs, this PFD agrees with Staff that these issues should be addressed in Case No. U-20757 through the work of the CCC. This PFD recommends that in its work, the CCC review the timing requirement of the appropriate certification form and issue a report with recommendations to increase the effectiveness of DTE's medical and critical care programs and to ensure that all eligible customers can avail themselves of the protections by March 2026. Further, this PFD recommends that the Commission direct DTE to publish its internal guidance for eligible conditions, affirmatively reach out to medical providers, and provide fulsome and timely explanations and an appeal process to customers denied entrance into the programs.

The DAAO made several recommendations for shutoff moratoria. However, in Case No. U-21534, the Commission stated that rate cases are not the appropriate forum to consider shutoff moratoria and suggested that they are more properly addressed through other venues, such as the EAAC.[2574] Therefore, this PFD recommends that to the extent it is not already an assigned task, that the Commission direct the EAAC to consider the following: (1) seasonal summer shutoff protections that account for both extreme heat and wildfire smoke; (2) expanded condition-based summer shutoff protections that set a conservative heat index threshold for all utilities accounting for

[2574] January 23, 2025 order in Case No. U-21534, p. 463.

humidity and the duration of a heat wave; (3) blanket shutoff protections for pregnant people and households with children; (4) permanent medical/critical care protections for households with a documented condition that requires uninterrupted access to energy; and (5) shutoff protection for households that have requested participation in an EWR or assistance programs but have been waitlisted or denied because of insufficient availability. Further, the EAAC should analyze the costs of a complete moratorium on shutoffs for non-payment and the specific costs of shutoffs, as well as the value of reduced shutoffs in customer benefits and reduced operating costs.

D. Environmental Justice

Mr. Kryscynski testified that DTE considers environmental justice (EJ) in its grid planning in three ways: (1) incorporating EJ considerations in the GPM, which prioritizes investments; (2) investing in programs to improve system performance in EJ communities experiencing poor reliability; and (3) providing support through community outreach to vulnerable customers experiencing outages during storms.[2575]

According to Mr. Kryscynski, DTE defines a vulnerable or EJ community as a census tract with a MiEJ Screen composite score at or above the 80th percentile.[2576] He stated that DTE has 483 EJ communities representing 29% of the total census tracts in its service area and accounting for approximately 550,000 residential customers. He also noted that the EJ census tracts include 1,032 circuits or 32% of total circuits and 8,080 circuit miles or 19% of total distribution miles.[2577]

[2575] 3 Tr 1222.
[2576] 3 Tr 1223.
[2577] 3 Tr 1230.

He presented a reliability analysis of DTE's census tracts where the data was grouped into reliability quartiles, with first quartile customers experiencing the best reliability and fourth quartile customers experiencing the worst reliability.[2578] He explained that the data demonstrates that EJ communities generally see better reliability than the system average in SAIFI and SAIDI in both All-Weather and Non-MED.[2579]

Mr. Kryscynski testified that DTE's program investments show that the Company is following through on its commitment to improve service reliability in EJ communities.[2580] He stated that from 2020 to 2024, 85%, 60%, and 23% of DTE's investment in 4.8kV Hardening, 4.8kV Conversion, and Tree Trim programs, respectively, was made in EJ communities.[2581] And he asserted similar investments are planned for 2025-2026.[2582]

Mr. Kryscynski testified that DTE uses an "EJ Multiplier" to adjust the benefit cost ratios that are used to prioritize investments within the PTMM programs and the automation programs. He stated that DTE has recently performed reliability work, or is planning it in 2025-2026, for about 50% of the 185 distribution circuits with the worst reliability performance (in the 4th quartile) that are also identified as EJ communities.[2583]

Mr. Kenworthy commended DTE for incorporating EJ into its investment prioritization tools and business processes. Building on that progress, he recommended that reliability reporting include distributions, not just averages, across EJ gradations, and

[2578] 3 Tr 1224-1229, Figures 4-7.
[2579] 3 Tr 1230-1236, Tables 5-8.
[2580] 3 Tr 1236-1243, Tables 10-17.
[2581] 3 Tr 1242, Table 10.
[2582] 3 Tr 1242, Table 11.
[2583] 3 Tr 1243.

that investment decisions pair the MiEJScreen tool with reliability and energy-burden indicators so that investments increase reliability without worsening affordability.[2584]

Mr. Tan testified about the benefits of regression analysis to analyze reliability metrics to better understand how different communities are experiencing outages. He noted that he presented regression analyses in Case Nos. U-21297 and U-21534 and even though he did not run a regression analysis on DTE's reliability metrics in this case, he is still recommending that the Commission order the Company to run regression analysis for every rate case, as well as DTE's Distribution Grid Plans. He noted that this would be consistent with the Commission's directive in Consumers' 2024 Rate Case, Case No. U-21585.[2585]

Ms. Nichols asserted that there are two main problems with DTE's EJ analysis. First, the MiEJ Screen tool fails to provide a sufficiently comprehensive picture of individual neighborhoods, households, or customer sub-groups within a given census tract as many tracts, including those with MiEJ Screen scores at or above the 80th percentile, vary widely in terms of income levels, housing conditions, and energy needs.[2586] Second, she asserted that DTE's practice of measuring the success of its investments in EJ communities by comparing service reliability in EJ census tracts to the systemwide average is both flawed and misleading. She noted that Consumers recognized in Case No. U-21585 that comparisons to systemwide averages to determine how EJ census tracts perform do not reveal service disparities because most vulnerable

[2584] 4 Tr 3630.
[2585] 4 Tr 3695-3696.
[2586] 5 Tr 4122.

census tracts are urban, and urban areas generally experience more reliable service than the many non-urban census tracts included in systemwide metrics.[2587]

Ms. Nichols asserted that in Case No. U-21534, the Commission adopted DAAO's recommendation that DTE evaluate changing demographics over time in the census tracts it prioritizes for EJ investments and the Commission expected that DTE would "work with interested persons to incorporate additional EJ-related considerations" into its system planning and infrastructure investment processes.[2588] However, she asserted, DTE has conceded it has not yet performed any evaluation, does not have a timeline for doing so, and has offered no plans to work with DAAO or other interested parties.[2589]

Ms. Nichols also asserted that DTE has not provided any evidence or analysis to show that its EJ multiplier has or will produce greater investment in projects benefiting vulnerable communities.[2590] Additionally, she testified, the multiplier is calculated based on the percentage of customers who would benefit from a given project who "live in a vulnerable census tract," which is problematic because of the flawed methodology that DTE uses to identify vulnerable communities.[2591]

Based on the foregoing issues, Ms. Nichols made four recommendations. First, she recommended that the Commission direct DTE to immediately conduct and incorporate an analysis of changing demographics over time within the census tracts it has identified for EJ prioritization. Second, she proposed that the Commission require DTE to immediately conduct an analysis comparing service reliability in vulnerable census

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[2587] 5 Tr 4123.
[2588] 5 Tr 4125-4126.
[2589] 5 Tr 4126-4127.
[2590] 5 Tr 4128.
[2591] 5 Tr 4129.

tracts to non-vulnerable census tracts with similar population densities and other characteristics, such as urban EJ to urban non-EJ, and develop a comprehensive investment plan to eliminate any service disparities.[2592] Third, she testified that the Commission should require DTE to immediately conduct and incorporate into its equity considerations an analysis of the extent to which projects in vulnerable census tracts are benefitting residential versus commercial customers. Lastly, she recommended that the Commission require DTE to perform an analysis before its next general rate case to determine if, and whether, its EJ multiplier is actually resulting in increased selection of projects benefiting vulnerable communities.[2593]

Detroit resident, Ms. Watts, detailed the significant difficulties she and others in her Charlevoix Village community, especially seniors and low-income households, face due to frequent DTE outages. She testified that when she is experiencing an outage, she notices that the lights are still on across Kercheval Avenue, which has underground powerlines, while she does not. She opined that the disparity in infrastructure between her community and the community on the other side of the street may be based on different socioeconomic and racial profiles.[2594] Ms. Watts testified that she is concerned that DTE practices "utility redlining" because it invests less in lower-income neighborhoods, even though lower-income neighborhoods have less reliable power lines and more outages. She maintained that DTE's rate hikes, which are used to pay for the

[2592] 5 Tr 4129-4130.
[2593] 5 Tr 4130.
[2594] 5 Tr 4185.

grid, impact lower-income neighborhoods the most, but lower-income communities do not feel meaningful changes or benefits.[2595]

Mr. Kinkhabwala asserted that the models and benefit cost analysis DTE uses to prioritize its distribution investments rely on tools, such as the ICE calculator, that undervalue outages generally and weigh commercial and industrial outages more heavily than residential ones.[2596] Instead of the ICE calculator, he supported the use of an alternative method developed by PSE Healthy Energy that assesses the impacts of outages relative to net household income after essential expenditures and allows them to be considered as part of a customer's energy burden. He testified that considering outage expenses as an energy expense expands the energy burden concept to "resilient energy burden."[2597] Using this method, he presented data showing that households in Huron County, Sanilac County, and much of Wayne County face resilient energy burdens of more than $1,000 per household per year.[2598]

Mr. Kinkhabwala asserted that DTE may also overinvest in communities with few residential customers since the EJ multiplier used in its GPM model only measures the fraction of residential households within a given census tract and not the actual number of residential households.[2599] He testified that DTE should better account for the number of residential customers on given circuit rather than just the proportion of customers living in an EJ community when prioritizing EJ in its GPM model.[2600] He asserted that there are

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[2595] 5 Tr 4191.
[2596] 5 Tr 4231-4235.
[2597] 5 Tr 4235.
[2598] 5 Tr 4235-4236, Figure 7.
[2599] 5 Tr 4237-4238.
[2600] 5 Tr 4249.

other flaws in the way DTE considers EJ in its investment planning, including that the GPM model is limited to considering only those projects that DTE has already chosen for implementation and the Company's complimentary Reliability Model does not consider EJ communities.[2601] He further asserted that DTE's Frequent Outage Programs, including the Customer Excellence (CE) program and the Strategic Reliability Improvement Program (SRIP), do not appear to consider the community served when selecting circuits for investments.[2602] He suggested that EJ considerations should be built into the CE and SRIP programs to further target disadvantaged communities.[2603]

Mr. Kinkhabwala supported the use of non-wires alternatives (NWAs) such as DR and solar paired with energy storage (solar+storage), either behind or in front of the meter, to provide resilience during extreme weather events.[2604] He asserted that solar+storage, and energy efficiency can reduce customer bills as opposed to increased distribution side investments that put upward pressure on rates.[2605] He opined that, ideally, resilient backup energy would be available in every household, but until it is available to all, it should at least be available to the most vulnerable, and if not in the home, then at least in community-serving resilience hubs, such as schools, libraries, places of worship, and community centers, that can provide critical services during power outages.[2606] Mr. Kinkhabwala discussed the costs and benefits of resilience hubs and the results of a study by NREL on behind-the-meter DR deployment in Highland Park, Michigan. He noted that

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[2601] 5 Tr 4238-4239.
[2602] 5 Tr 4239.
[2603] 5 Tr 4249.
[36] 5 Tr 4239-4240.
[2605] 5 Tr 4240.
[2606] 5 Tr 4244.

while the costs of resilient DR options are significant, they are trending downward, such that the NPV of these investments is improving, especially if additional benefits are considered.[2607] He asserted that DR such as solar+storage on a resilience hub or within a microgrid can reduce the impacts of MED outages on local communities in contrast to DTE's reliability investments, which have been ineffective.[2608] According to Mr. Kinkhabwala, DTE needs to include DR and NWAs that can improve affordability and other targeted resilience in its benefit cost analysis models and planning and DTE should include analysis of these alternatives in its next rate case, IRP, and distribution plan.[2609]

In rebuttal Mr. Chiu testified that DTE may consider NWAs in its benefit cost analysis models in the future, while Mr. Rademacher testified that Mr. Kinkhabwala's proposal is impractical and significantly underestimates the costs of NWA and DR.[2610] Mr. Rademacher questioned the customer buy-in of residential solar+storage and implied that grid investments that resolve the root cause of service unreliability are more practical.[2611] He maintained that DTE investigates and appropriately pursues solar+storage in certain specific cases where it makes sense, but applying the approach everywhere is impractical, prohibitively expensive, and does not address the root causes of outages[2612].

Mr. Kryscynski countered Mr. Kinkhabwala's suggestion that the EJ multiplier causes the GPM model to skew towards communities with few residential customers. He presented data that he stated shows that there is no apparent trend between the number

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[2607] 5 Tr 4244-4248.
[2608] 5 Tr 4247.
[2609] 5 Tr 4250.
[2610] 3 Tr 1156, 950.
[2611] 3 Tr 950.
[2612] 3 Tr 951.

of customers impacted by a project and a declining EJ score.[2613] He stated that an analysis of projects that impact more than 10,000 customers shows there are more projects serving communities with more than 50% EJ customers than there are projects that serve communities with less than 50% EJ customers.[2614]

According to Mr. Krysynski, DTE plans to continue to rely on the MiEJ Screen tool to prioritize investments and it does not believe additional EJ analysis is appropriate.[2615] He testified that DTE's approach to prioritize EJ investments, including the use of the MiEJ Screen tool, appropriately aligns the geographic scale of distribution and subtransmission projects with EJ populations as defined by census tracts.[2616] And he countered that more granular breakdowns, such as individual streets or neighborhoods, are not particularly useful, as grid solutions are typically planned and implemented at the circuit or substation level.[2617]

As for Ms. Nichols' testimony regarding the Commission ordered analysis on changing demographics over time, Mr. Kryscynski testified that conducting this analysis within the three-month timeframe before this case was filed posed challenges, but DTE plans to include the analysis in the 2026 Distribution System Plan (DSP), after collaborating with Staff and interested parties. He added in response to Mr. Tan, that DTE will also include a regression analysis in the 2026 DSP.[2618]

[2613] 3 Tr 1276-1278, Figure 1.
[2614] 3 Tr 1277-1278, Figure 1.
[2615] 3 Tr 1291-1292.
[2616] 3 Tr 1292.
[2617] 3 Tr 1292-1293.
[2618] 3 Tr 1293.

Mr. Kryscynski responded to Ms. Watts, stating she did not provide any evidence substantiating her opinion that DTE does not appropriately invest in low-income communities, and he referred to his direct testimony as providing evidence to the contrary.[2619] He pointed to the Company's reliability data as confirming that EJ communities, which are those in the top 80th percentile and above of MiEJScreen scores, consistently experience equal or better reliability than the system average for both SAIFI and SAIDI in both All-Weather and Non-MED.[2620]

In briefing, DTE reasserts its disagreement with the suggestion that the EJ multiplier skews its modeling towards communities with few residential customers.[2621]

In its brief, the DAAO argues that just because a significant portion of DTE's reliability improvement work is being conducted in EJ communities, does not mean that there are not disproportionate reliability problems in these communities and that more does not need to be done to address existing inequities.[2622] The DAAO assert that Consumers does a better job of analyzing its distribution system data and that the Commission should require DTE to conduct an analysis, as Consumers has done, that compares the reliability of EJ urban communities to comparable non-EJ urban communities.[2623] The DAAO further argues that DTE's current investments and proposals, as well as its inaccurate analysis of reliability in EJ communities, fail to meet Commission directives in Case No. U-21534 and that since DTE has not provided

[2619] 3 Tr 1294.
[2620] 3 Tr 1294-1295, Table 5.
[2621] DTE brief, 45.
[2622] DAAO brief, 66-67.
[2623] DAAO brief, 67-68.

required EJ analyses in this proceeding, the Commission lacks the necessary information to determine whether DTE is making investments equitably.[2624]

In briefing, the CEO elaborates upon its witnesses' testimony and recommends that the Commission direct DTE to strengthen its EJ reliability reporting as recommended.[2625]

DTE's reply reiterates its witnesses' testimony, while the CEO's reply brief does not address EJ. The DAAO's reply brief argues that DTE fails to meaningfully rebut any of the evidence provided by its witnesses and contends that several other parties have expressed concerns about deficiencies in DTE's models.[2626] DAAO's EJ-related recommendations include requiring DTE to improve reliability and build energy resilience through NWAs, such as solar+storage and to pay a meaningful and prompt outage credit.[2627]

This PFD finds that DTE did not provide the analysis on changing demographics over time, as directed in Case No. U-21534 and recommends that the Commission reaffirm that DTE must include this analysis in its next rate case and in its 2026 DSP. DTE's explanation for failing to provide the analysis—that it did not have time to complete it before filing the instant rate case—is troubling, since it was the Company's decision to request another rate increase so soon after the order in Case No. U-21534 was issued.

This PFD agrees with the intervenors that DTE's EJ analyses can and should be improved and recommends that the Commission require DTE to do the following: (1) run

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[2624] DAAO brief, 69-70.
[2625] CEO brief, 42-43.
[2626] DAAO reply, 13-14.
[2627] DAAO reply, 16.

a regression analysis in all its rate cases and DSPs; (2) conduct an analysis comparing service reliability in EJ census tracts to non-EJ census tracts with similar population densities and other characteristics, such as urban EJ to urban non-EJ; (3) include distributions, not just averages, across EJ gradations in its reliability reporting; and (4) pair the MiEJ Screen tool with reliability and energy-burden indicators so that investments increase reliability without worsening affordability.

In addition, the Commission should require DTE to better account for the number of residential customers on a given circuit rather than just the proportion of customers living in an EJ community, if possible, when prioritizing EJ in its GPM model, incorporate EJ into its Reliability Model, and build EJ considerations into the CE and SRIP programs to further target disadvantaged communities.

E. Accounting Requests

As Staff points out, DTE used its rate of return on permanent capital (9.45%) as the return on the tree-trimming surge regulatory asset revenue requirement. Staff argues that in Case No. U-21297, the Commission approved a return at the Company's short-term debt cost rate, which should continue.[2628] Therefore Staff reduced DTE's revenue requirement for the tree-trimming regulatory asset by $7.062 million. This PFD agrees and recommends adoption of Staff's amount.

Further, this PFD finds that the Monroe regulatory asset revenue requirement be calculated based on the decisions in the Commission's final order.

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COST OF SERVICE

[2628] Staff brief, 175-176.

DTE's COSS was presented through the testimony and exhibits of Mr. Burgdorf and Mr. Cejas Goyanes. DTE utilized an Unbundled Cost of Service (UCOS) study, which was developed utilizing the systemic functionalization, classification, and allocation of its fixed and variable costs to provide service to each customer class.[2629] Functionalization assigns all costs to the major functions, Production (i.e., Generation and Transmission) and Distribution. Classification divides these costs into customer-related costs, demand-related costs, and energy-related costs. The last step, allocation apportions the costs to the respective customer class based upon each class's responsibility for the incurrence of these costs.[2630]

Mr. Cejas Goyanes explained how he functionalized DTE Electric's costs, how the UCOS allocates costs to DTE Electric's various customer classes, and that he used the 4CP 75-0-25 method for the allocation of purchased power capacity costs in the forecasted UCOS and 12CP 0-0-100 for fuel costs, consistent with the methods approved by the Commission in the January 23, 2025 Order in Case No. U-21534.[2631]

Proposed adjustments to the Company's COSS were made by the parties and are discussed below.

A. COSS Allocation Adjustments

1. PSP, RIA, LIA, and RSC Credit Allocation

[2629] For purposes of this PFD, the discussion of the Company's UCOS and the use of the acronym COSS are interchangeable.
[2630] DTE brief, 218.
[2631] 4 Tr 2548-2561; Exhibit A-16, Schedule F1.3; DTE's Initial Brief, p. 217-219.

Staff challenged the Company's COSS allocator for the Company's PSP pilot, Residential Income Assistance Credit (RIA), Low Income Assistance Credit (LIA), and the Residential Service Senior Citizens Provision (RSC).[2632]

Staff witnesses Braunschweig and Pung asserted that the Company's cost allocation on a customer count basis rather than a total cost-of-service-basis is inappropriate because costs (or lack of revenue) cannot always be tied directly to a class.[2633] Staff asserted that the revenue shortfall resulting from residential credits or energy assistance should not be attributed solely to the residential customer class, even though only residential customers receive those credits.[2634] Staff characterized this shortfall as a general business cost, not directly caused by the nature of any customer's service but, rather, by factors such as customers' ability to pay, which, Staff reasoned, is unrelated to energy service itself.[2635] Staff, also cited to Consumers' allocation of revenue shortall on a total cost of service in rate design models, and thus recommended a change in the method for the allocation of RIA, LIA, and RSC credits, along with PSP, from one where the shortfall is allocated based on the number of customers (which is allocator 800 in the COSS), to one based on each class's share of revenues (based upon allocator 402).[2636]

In its initial brief, Staff cites MCL 460.11, arguing that "[t]he language in the statute is clear when it states in general that rates must be 'equal to the cost of providing service

[2632] 5 T Tr 5217-5220; 5 Tr 5248; Staff's Initial Brief, p 197-198.
[2633] 5 Tr 5217.-5219; 5 Tr 4966.
[2634] Staff brief, 220.
[2635] Staff brief, 220.
[2636] 5 Tr 4996-4967; 5 Tr 5218-5219; 5 Tr 5224-5225; Staff brief, 197-198.

to each customer class.'"[2637] Further, Staff argues that the statute requires low-income and eligible senior customer rates be established and that a shortfall for those costs must be recovered according to a method "upon all customer classes."[2638] Thus, Staff concludes: (1) costs associated with energy assistance programs authorized under MCL 460.11(2) have to be recovered from all customer classes, and subsection 2 is exempt from the clause requiring cost-based rates; and (2) the statute does not state by which allocator the costs must be recovered except that they must be recovered from all customer classes.[2639] Staff argues that its proposal is consistent with the statute and should be adopted by the Commission.

While ABATE concedes that these costs "may be *general* costs of business," it disagrees with Staff's recommendation, arguing that they are costs incurred only by the residential class.[2640] ABATE argues that Staff's proposal would not reflect cost causation and would shift costs to customers which do not cause them.[2641] Specifically, ABATE notes that the only group of customers causing or driving the costs are residential customers in need of assistance paying their utility bills.[2642]

Additionally, while ABATE witness Andrews agreed that the statute requires that these costs be allocated to all customer classes, he reasoned that the statute does not require these costs to be allocated to all customers on the basis of the total billed revenues of each customer class, and noted that the statute, as a whole, requires cost-

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[2637] Staff brief, 199.
[2638] Id.
[2639] Id.
[2640] 4 Tr 3227.
[2641] ABATE brief, 77-78.
[2642] 4 Tr 3227.

based rates.[2643] He explained that changing the allocations, as suggested by Staff, from number of customers to total billed revenue, would: (1) reduce the residential portion of these costs by $14.0 million; (2) result in a reduction in the residential class's allocation of the total costs from 90% to 52.3%; and (3) inappropriately allocate an additional $6.2 million to Commercial customers and $7.3 million to the Primary, Sub-transmission, and Transmission customers, even though these costs were entirely incurred to serve the Residential class.[2644] Citing the increase of $7.1 million for Primary customers, Mr. Andrews urged the Commission to reject Staff proposal as inequitable and out of step with the entire cost-based rate statute.[2645]

Finally, ABATE argues that DTE has complied with MCL 460.11(2) requiring a utility to include proposed eligible low-income customer and eligible senior customer rates and a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes and has complied with MCL 460.11(1) requiring cost-based rates.[2646] ABATE concludes that Staff's proposal moves the rate design away from equitable allocation and cost causation, which it argued is "incongruous with the cost-based requirement of MCL 460.11."[2647] Thus, ABATE recommends rejection of Staff's proposal to allocate these costs to all customer classes on the basis of the total billed revenues of each customer class and further recommends continuation of DTE's "long-

[2643] 4 Tr 3227.
[2644] 4 Tr 3227-3228; ABATE brief, 78.
[2645] 4 Tr 3228; ABATE brief, 78.
[2646] ABATE brief, 78
[2647] ABATE brief, 78-79.

standing practice of allocating these costs to all customer classes on the basis of the number of customers in each customer class."[2648]

Although the Company acknowledges the arguments of Staff and ABATE, it did not specifically take a position on this issue in testimony or in briefs.

The record reflects that DTE's allocation methodology for RIA, LIA, and RSC credits is consistent with prior practice and has been approved by the Commission in prior cases. Further, the record reflects that Staff did not utilize its proposed allocation methodology in its case.[2649] Notably, Staff highlighted that this issue is a topic being considered in Case No. U-20757.

Although the Company did not object to Staff's recommendation in its initial brief, this PFD is not convinced that Staff's proposed methodology is warranted at this time, in light of the fact that the same proposal is being addressed in Case No. U-20757. Accordingly, this PFD recommends the Commission approve DTE's allocation methodology for PSP, RIA, LIA, and RSC credits and deny Staff's proposed modification of methodology until such time as there is a more robust evidentiary presentation supporting such a change.

2. TEP Costs Allocation

In testimony and in in its initial brief, ABATE challenged DTE's functionalization of TEP costs.[2650] Citing DTE's economic analysis of its TEP, Mr. Andrews explained that the Company's TEP will not provide a net cumulative present value (NPV) benefit to DTE's customers as a whole until approximately 2047 – nearly 20 years after the first costs were

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[2648] ABATE brief, 79.
[2649] 5 Tr 5218.
[2650] 4 Tr 3206; ABATE brief, 73.

incurred.[2651] Thus, ABATE proposes that the past claim that these costs should be allocated to customer classes based on class revenues because they are being pursued to provide lower rates for all is "highly tenuous" and should be rejected.[2652] Mr. Andrews asserted that the current proposed allocation is based on information not present when the methodology was proposed (by Staff) and approved by the Commission in Case No. U-21297.[2653]

In its initial brief, ABATE characterizes the difference between this rate case and the date on which this program may result in downward pressure on rates as a "chasm."[2654] ABATE argues that TEP costs should be allocated on the basis DTE initially proposed in Case No. U-21297, which would be based on net distribution plant, given that these investments principally involve distribution system investments.[2655] ABATE contends that there are multiple problems with allocating costs in accordance with revenue based on the extent to which this cost category lowers rates overall, including: (1) it is based on claimed benefits, not cost causation; (2) TEP costs are not expected to provide a benefit by lowering costs for almost a decade; (3) the Company's TEP reflects total costs through 2028 of $145 million which will create an upward pressure on rates through at least 2032; and (4) maximum rate benefits from the TEP will not be reached until 2064.[2656]

[2651] 4 Tr 3206; ABATE brief, 74.
[2652] 4 Tr 3206-3207; ABATE brief, 73.
[2653] 4 Tr 3207-3209.
[2654] ABATE brief, 74.
[2655] 4 Tr 3207.
[2656] ABATE brief, 74 (citations omitted).

Noting that "these costs should not be recovered from customer classes which have nothing to do with causing them," ABATE recommends allocation of TEP costs only to the customer classes that are choosing and pursing installation of EV chargers and are, thus, directly benefitting from the program.[2657] Therefore, ABATE promotes defaulting to the methodology utilized by DTE initially, as proposed in Case No. U-21297 which allocated TEP regulatory asset costs on the basis of distribution net plant- as reflected Exhibit AB-3.[2658] ABATE also proposes that DTE be required, in its next rate case, to identify total paid rebates by customer class and voltage level in each customer class so that this information can be used for the allocation of TEP costs in the next DTE rate proceeding.[2659]

In rebuttal, Staff witness Krause objected to ABATE's recommendation for a change in the functionalization and allocation of TEP costs. Staff disagreed with ABATE's characterization of the TEP allocator as costs that "in no way related to power supply," and asserted that TEP program expenditures help install EV charging infrastructure which, in turn, leads to EV loads that require generation in order to be served.[2660] Mr. Krause pointed to the Company's IRP and asserted that it demonstrates load forecasting for EV growth is an essential part of power supply planning.[2661] He noted that because power supply planning necessarily involves power supply costs, Staff's position in Case No. U-21297 supported a revenue allocator that included power supply.[2662] While Mr.

[2657] 4 Tr 3207, 3211; ABATE brief, 75.
[2658] 4 Tr 3208-3211.
[2659] 4 Tr 3211; ABATE brief, 75.
[2660] 5 Tr 5251.
[2661] 5 Tr 5251-5252.
[2662] 5 Tr 5251-5252.

Krause did not support ABATE's recommendation for the direct assignment of TEP rebates by voltage level in the Company's next rate case, he recognized this method as better than the net distribution plant method recommended by ABATE, asserting that assignment of rebates to voltage levels, if approved, should be extended to previous make-ready costs as well, and reiterated Staff's preference for an allocator that includes power supply.[2663]

MEIU witness Schuster characterized the TEP cost allocation as a policy decision and testified that having an accurate accounting of the total amount of revenue expected from EV charging, and an appropriate amortization schedule that reflects the true useful life of most EV chargers is important.[2664] To that end, she proposed that Company account (as accurately as possible) for 100% (not 10%) of additional revenue generated by EV charging in its service territory and extend the amortization schedule of TEP costs.[2665] She asserted that the "current policy debate" is based on an assumed total revenue that represents only 10% of the total additional expected revenue and inflates costs due to the 5-year amortization schedule, and "serves to unreasonably limit the NPV benefit of the TEP programs to all DTE customers."[2666] Thus, she recommended the Commission reject ABATE's proposal to allocate the TEP regulatory costs on the basis

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[2663] 5 Tr 5252.
[2664] 5 Tr 4016.
[2665] 5 Tr 4016.
[2666] 5 Tr 4016. As discussed above, MNSC witness Woolley appears to support the basis of MEIU's recommendation as he also notes that the BCA for the Company's TEP evaluates load only from rebated chargers, accounting for roughly 10% of overall EV load through, saying the BCA is "too narrow and conservative, which "inflates near-term rate pressure and delays ratepayer benefits until 2033." He further asserts that the BCA "front-loads rebate costs with a 5-year amortization, counts only 10% of projected EV load (ignoring network effects), omits societal benefits, and consequently risks associating the TEP with Michigan's growing affordability concerns . . ." He promotes extending the amortization period of 5 years, which he says creates short-term rate pressure, to smooth costs and bring forward the point at which customers see rate benefits. 5 Tr 4797.

of net plant, and she supported a more comprehensive evaluation of all benefits in the Company's service territory attributable to all charging, using a reasonable amortization schedule, and continue the revenue-based allocation across all customer classes, as approved in Case No. U-21297, until that time.[2667]

Ms. Schuster agreed with ABATE's recommendation to require the Company to identify total paid rebates and voltage levels by customer class in its next rate case proceeding, so long as the Company is also required to present an accounting scheme that more accurately captures the full NPV benefits, including all revenue attributable to charging and associated network effects, provided by its TEP program across customer classes, and present an amortization schedule that more appropriately reflects the true useful life of EV charging equipment.[2668]

Neither Staff, ABATE, nor MEIU address this issue in briefing. While DTE objects to ABATE's proposal, it did not address the position of Staff or MEIU in its initial brief.

As noted above, this PFD finds MEIU's arguments to be persuasive. Since the Commission issued its order in Case No. U- 21297, the issues surrounding EV adopting and costs have continued to evolve. To properly evaluate how the costs associated with the Company's TEP are functionalized and allocated to support cost of service principles, more granular information to support that allocation may be required. Thus, this PFD recommends the Commission adopt the recommendations of MEIU.

3. Production Cost Allocator

[2667] 5 Tr 4016.
[2668] 5 Tr 4016-4017.

Although the production allocator was not an issue in this case, Mr. Krause made recommendations regarding information to be provided on production cost allocation in future rate cases.[2669] Specifically, Staff recommends that the Company: (1) run and present the standard coincident peak (CP) tests in its next rate case; (2) provide some insight into how it views seasonal or monthly load growth in the future; and comment on the potential for changing the production allocator based on seasonal load shift.[2670] Citing potential growth in electrification of space heating, that would challenge the traditional understanding of production allocation on 4CP summer, Mr. Krause reasoned that new loads, such as data centers and transportation electrification could create a leveling of load throughout the year. The Company did not address this issue in its Initial Brief.

As electrification continues to grow in Michigan there may be some merit in having utilities, such as DTE, provide information on how it sees growth impacting the production cost allocator based on seasonal load shift. Thus, this PFD recommends the Commission consider approving Staff's recommendation or otherwise creating a separate proceeding to address these types of concerns on a utility industry-wide basis.

B. State Reliability Mechanism Capacity Charge

Mr. Goyanes testified regarding the Company's calculation of the SRM capacity charge, and he sponsored Exhibit A-16 which calculated the charge at $486.75/MW-day.[2671] Mr. Burgdorf also provided calculations related to the SRM capacity charge and

[2669] 5 Tr 5248' Staff brief, 193.
[2670] 5 Tr 5248.
[2671] See 4 Tr 2562-2566; see also Exhibit A-16, Sched F1.5, p 1, line 17.

its related true-up mechanism, including calculations related to the Company's wholesale energy sales net of fuel-related costs.[2672]

Staff witness Pung testified that he calculated the SRM capacity charge at $460.52 per MW-day, or $26.24 per MW-day less than DTE, and he recommended that the Commission adopt that figure.[2673] He observed that the Company's proposed SRM charge was more than double the current charge, explaining that the primary cause of this sharp increase was the Company's "Reconciliation of Net Sales Benefit Difference in which it reconciled the 2024 projected Energy Sales Revenues net of fuel costs from Case No. U-21297 with the actual amounts that occurred in that year."[2674] He explained that DTE's reconciliation showed a difference between actual and forecasted amounts of $1.12 billion, and that the largest factor was the difference between projected energy market revenues and actual revenues.[2675] Mr. Pung stated that, in discovery, the Company attributed the large difference to lower MISO wholesale energy market prices compared to forecasted prices in Case No. U-21297.[2676] Mr. Pung raised concerns about DTE's current energy market sales forecast noting that the data for the most recent five years does not appear to adequately support the Company's forecast.[2677] He recommended requiring the Company to provide all the data it uses to make its energy market sales forecast as part of its initial filing in its next rate case, and to include a calculation of its forecast in excel format with all formulas intact.[2678]

[2672] See 4 Tr 2067-2071; see also Exhibit A-26, schedules P2, P3, and P4.
[2673] 5 Tr 4962, 4967, see also Exhibit S-6, Schedule F1.5, lines 11 and 17.
[2674] 5 Tr 4963.
[2675] 5 Tr 4963.
[2676] 5 Tr 4964.
[2677] 5 Tr 4964.
[2678] 5 Tr 4964.

Mr. Zakem testified regarding the SRM capacity charge, and he comprehensively described the operation of the SRM charge and the statutory true-up mechanism associated with the charge in MCL 460.6w(4).[2679] He stated that in his review of the 39 cases addressing the SRM charge since its enactment in 2016, only four (all involving DTE Electric) have addressed the true up mechanism.[2680] Mr. Zakem specified that none of the four true up cases addressed the immediately preceding case that set an SRM charge despite statutory language in MCL 460.6w(4) requiring that "[t]he true-up shall be reflected in the capacity charge in the subsequent year."[2681] Mr. Zakem explained that this fact "point[s] to an obvious flaw in the SRM statute specifying true ups: the cases that set an SRM Charge based on projected energy market sales net of fuel and the cases that true up the projected values to actual energy market sales net of actual fuel take time, significant amounts of time."[2682]

He further explained that an SRM charge is set at the date of the final order in a rate case, and that the next setting of an SRM charge occurs at the time of the final order in the next rate case, which could be over a year or more away.[2683] Mr. Zakem stated that a utility and a customer can only be trued up if the customer pays an SRM charge in one year and also pays an SRM charge in a later year, but the result of the timing flaw in the SRM statute means that "SRM charges and true-ups end up infinitely pancaked."[2684] Mr.

[2679] In doing so, Mr. Zakem provided a general overview of the function of the true up within the statute, and he defined the specific terminology he preferred to use when discussing the SRM charge and the true-up process. This testimony was extensive and is important to understanding Mr. Zakem position; however, for the sake of brevity, it will not be summarized in this PFD which instead refers the reader to 5 Tr 3885-3893 for more information.
[2680] 5 Tr 3894-3895. See Also Exhibit EM-3.
[2681] 5 Tr 3896 (quoting MCL 460.6w(4)).
[2682] 5 Tr 3896.
[2683] 5 Tr 3896.
[2684] 5 Tr 3897.

Zakem opined: "No matter what the rate case test period is for setting the capacity portion of the SRM charge, the time period for actuals for the offsets value of energy market sales net of fuel must match the test period. This has not been the process in true-ups for DTE."[2685]

Mr. Zakem also testified that there were inconsistencies in the way that the true-up method was calculated related to the variable cost of purchased power in the "net of fuel" part of projected energy market sales.[2686] He explained that DTE included a portion of purchased power costs in its determination of projected energy market sales revenue net of fuel costs.[2687] By contrast, he observed that Consumers does not include a portion of purchased power costs in its projected energy market sales revenue net of fuel costs, and that the Commission rejected Consumers' request to do so in Case U-20963.[2688] He also asserted that UPPCO does not used purchased power costs in its projections.[2689]

Mr. Zakem expounded upon the flaws in the current true-up methodology. He explained:

> The timing flaw in the SRM statute, coupled with the current formulaic method for true-ups that has been implemented in all four of the SRM Charge cases that have included a true-up so far, results in each of the true-ups being in error. This will continue into the future as long as the present true-up method is applied -- that is, all future true-ups using the present method will be in error. Consequently, neither the utility nor the customer will be treated fairly under the present true-up method.
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> As stated previously, under the present true-up method, the customer and the utility can be trued up only if the customer that pays an SRM Charge in

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[2685] 5 Tr 3899.
[2686] 5 Tr 3899-3900. See also MCL 460.6w(3)(b) (which provides for the calculation of the capacity charge and directs the subtraction of certain energy market sales, net of projected fuel costs). Notably, Mr. Zakem provided further explanation of his use of certain terms related to the statute in 5 Tr 3892-3893.
[2687] 5 Tr 3901.
[2688] 5 Tr 3901-3902.
[2689] 5 Tr 3902.

> one year also pays an SRM charge determined in a later year. The result of the timing flaw in the SRM statute is that SRM Charges and true-ups end up infinitely pancaked.
>
> In an apparent attempt to "unpancake" overlapping cases for SRM Charges and true-ups, each true-up case attempts to back out the true-up amount from the previous case by reversing the true-up amount that was included in the previous case, which true-up amount was for the SRM Charge two cases ago. This merely creates an additional error if the customer owing an SRM Charge from the previous case was not billed an SRM Charge from two cases ago.[2690]

Citing the difficulty of describing the SRM true-up process in writing, Mr. Zakem referred to Exhibit EM-6 which shows a sequence of calculations relating to the four SRM charge cases ending with the current case.[2691] He explained that the current methodology used to implement the true up has the effect of ensuring that a customer does not benefit from a true up if it pays the SRM charge in one period but not in a subsequent period. Similarly, he explained that if a customer pays an SRM charge, but did not pay such a charge previously, then the customer erroneously absorbs the effect of a true up from a previous case.[2692] Mr. Zakem concluded that the current true-up method is affected by all previous true-up values, and that no payment of the SRM charge in any combination of time periods is correct or ever can be correct under the current method.[2693]

Mr. Zakem testified that no entity has ever been assessed an SRM charge because all load-serving entities have demonstrated sufficient capacity for the next four years. Accordingly, he stated that the soonest a SRM charge could be assessed is five years from now, and that a true up for such a charge could not occur for another year, i.e.

[2690] 5 Tr 3902-3903.
[2691] 5 Tr 3903; See also Exhibit EM-6.
[2692] 5 Tr 3905-3906.
[2693] 5 Tr 3908. See also Exhibit EM-6.

six years from the present.[2694] Mr. Zakem opined that there is "no urgency to continue the current faulty formulaic true-up method for the next six years" and that both DTE and Consumers believe that there is no need to calculate a true up until an entity pays an SRM charge.[2695] Accordingly, he explained that the Commission has time to deliberate and enact reforms of the methodology before applying it.[2696]

Mr. Zakem largely deferred to EM's brief to address the legal question of whether and how the Commission could modify the true-up process; however, he opined that the language of MCL 460.6w(4) "allow[s] a lot of room for workable methods" and that the statute did not dictate a single prescription for the true-up mechanism.[2697] He made two recommendations. First, he recommended suspending the current true-up methodology.[2698] Second, he recommended implementing a customer-specific SRM true-up that would apply to any customer that is assessed an SRM charge and that is triggered only if a customer is subject to an SRM charge. He explained that if a customer must pay an SRM charge, then the customer could be trued up on an ad hoc basis for that customer without revising present or future SRM charges.[2699] Mr. Zakem described his proposed process:

> A simple method for truing up a customer is to determine the difference between what the customer initially paid -- with projected energy market sales net of fuel -- compared to what the customer should pay with actual energy market sales net of fuel. Actuals, once they are available, would be substituted for projections in recalculating the SRM Charge, and the

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[2694] 5 Tr 3909.
[2695] 5 Tr 3909-3910.
[2696] 5 Tr 3910.
[2697] 5 Tr 3911.
[2698] 5 Tr 3913.
[2699] 5 Tr 3914.

customer would be billed for, or refunded, the difference between the two calculated charges.[2700]

Mr. Zakem testified that there were seven advantages to his proposed method: (1) both customers and the utility are treated fairly; (2) the customer does not have to pay an SRM charge in multiple periods just to be trued up for one period; (3) rates for full-service customers would no longer be affected by cumulative errors in projected energy market sales net of fuel; (4) there is no need for "pancaking," reversals, or re-reversals of previous true ups; (5) the customer's MW capacity obligation becomes irrelevant; (6) the recalculation of the SRM charge is easy; (7) it eliminates the opportunity for gaming the SRM charge with skewed projections.[2701]

Mr. Zakem opined that the Commission would not have to order his proposed method to begin immediately because the Commission and interested parties would have six years to come to an agreement on a new methodology so long as the current methodology was suspended.[2702] He provided his proposal for how his true-up method would change the SRM charge in this case on Exhibit EM-7.

In rebuttal, Mr. Burgdorf disputed that there are meaningful inconsistencies in how utilities treat PPA costs. He explained that, as DTE showed in Case No. U-21534, regardless of whether variable PPA costs are treated as offsets to energy sales or as capacity-related costs, the resulting SRM charge remains the same, making the categorization inconsequential.[2703]

[2700] 5 Tr 3914.
[2701] 5 Tr 3916-3917.
[2702] 5 Tr 3918.
[2703] 4 Tr 2077.

In briefing, Energy Michigan repeats the same points from Mr. Zakem's testimony already described above.[2704] Importantly, after quoting the full language of MCL 460.6w(4),[2705] Energy Michigan provides further legal argument regarding the Commission's ability to interpret the statute's language in such a way as to support Energy Michigan's proposal for the SRM true up mechanism:

> The Legislature could have said "shall implement" rather than "shall provide for," which would have clearly obligated the Commission to require a true-up process to be undertaken; instead, the "shall provide for" language gives the Commission discretion with respect to actually implementing a true-up once it has "provided" the mechanism. The next sentence, requiring that the "true-up shall be reflected in the capacity charge in the subsequent year" does not say that the "true-up mechanism" be "reflected" but rather that "the true-up" be. If, therefore, no true-up was undertaken, then there is no true-up to reflect in the subsequent year. Thus, the terminology provided by the Legislature allows a significant amount of room for the Commission to develop workable methods; and the "methodology" is already the same for how projected and actual offsets are worked into the calculation of the SRM Charge, as is shown on Exhibit EM-2 (AJZ-2) and described previously.[2706]

In turn, the Company's brief summarizes the testimony of the parties and repeats that the treatment of PPA costs has no meaningful impact on the SRM charge despite Mr. Zakem's suggestion otherwise. DTE asserts that this issue was settled and resolved in Case No. U-21534.[2707] The Company's brief appears to take no position on Energy Michigan's proposal relating to the true-up mechanism.

[2704] See generally Energy Michigan brief, 2-18.
[2705] "The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year." MCL 460.6w(4).
[2706] Energy Michigan brief, 15.
[2707] DTE brief, 224 (citing January 23, 2025 Order in Case No U-21534, p. 390.

Staff reiterates its request that the Commission direct DTE to include all the data it uses to make energy market sales forecasts, including intact formulas, in the Company's next rate case.[2708] Staff also acknowledges that the current formulaic true-up method "has significant flaws."[2709] Staff states that the current true-up method "is throwing the capacity and non-capacity revenue requirements far off the cost-to-serve[,]" and that the current true-up method produces a result "that does not adhere to cost-of service principles in Staff's opinion."[2710] Staff agrees with Energy Michigan that there is flexibility in how the Commission may provide for a true-up mechanism under MCL 450.6w(4) and agrees that the Commission should be guided by cost-of-service principles.[2711] Accordingly, Staff agrees that the current formulaic true-up method should be discontinued and the Company should be ordered to perform a true-up only if a customer is actually subject to the capacity charge and there is actual revenue to reconcile.[2712] Staff further explains the details of its proposal:

> Concerning Energy Michigan's proposal to implement a customer-specific SRM true-up, Staff recommends a calculation that is more consistent with how the initial SRM capacity charge is implemented even though the result will be the same. If a customer is assessed the capacity charge, it is charged for the amount of MW-Days the customer requires the Company to serve them capacity. Staff recommends that if a true-up became necessary, that it would also be calculated and applied in this manner. First, the capacity charge would be recalculated for the applicable period using actual energy market sales data net of actual fuel costs. Then you would take the difference between the original capacity charge using projected amounts and the capacity charge produced using actual amounts and apply it to the amount of MW-Days the customer was charged.[2713]

[2708] Staff brief, 193.
[2709] Staff brief, 191.
[2710] Staff brief, 191.
[2711] Staff brief, 191-192.
[2712] Staff brief, 192.
[2713] Staff brief, 192.

However, Staff specifies that if the Commission opts to retain the current true-up methodology, then approximately $329 million from prior years' true-ups in Cases U-18248 and U-20561 should be removed from the capacity revenue requirement because they have been trued up previously.[2714]

This PFD agrees with Staff's recommendation to require DTE to provide the data that it uses to make its energy market sales forecast as part of its initial rate case filing and to include a calculation of its forecast in excel format with the formulas intact.

This PFD appreciates Energy Michigan's thorough analysis of the problems characteristic of the current SRM true-up process and recognizes that the current process is cumbersome in its operation, and it suffers from many of the flaws aptly identified and explained by Energy Michigan. This PFD also agrees with Energy Michigan and Staff that the language of MCL 460.6w(4) allows for a certain degree of flexibility for the reasons stated by Energy Michigan in its briefing.[2715] Accordingly, this PFD agrees with Energy Michigan and Staff that the current formulaic true-up methodology should be discontinued in this case and that the Company should be directed to perform a true-up only if a customer is subject to the capacity charge and there is actual revenue to reconcile. This PFD recommends adopting Staff's recommended true-up methodology, which provides for a customer-specific true-up based upon the number of MW-days the customer requires the Company to provide them capacity.[2716]

Finally, this PFD declines to address Energy Michigan's statements related to ostensible inconsistencies related to purchased power costs in the SRM charge. As

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[2714] Staff brief, 192.
[2715] See Energy Michigan brief,15 (an excerpt from which was quoted earlier in this PFD).
[2716] See Staff brief, 192.

Energy Michigan's witness Mr. Zakem acknowledged, and as DTE argued, that issue was already addressed and resolved by the Commission in Case No. U-21534, and it need not be raised again here.[2717]

XI.

RATE DESIGN AND TARIFF ISSUES

Rate design refers to the framework to set prices and standards for the reliable provision of electricity services. This PFD breaks down rate-design issues into those affecting residential service and those affecting commercial and industrial service.

A. Residential Rate Design

1. Seasonal Distribution Rates

MNC witness Jester testified that he "continued to be dissatisfied with DTE's approach to rate design" saying that it provides improper price signals to customers and, in doing so, creates significant intra-class cross subsidies.[2718] Thus, Mr. Jester recommended the Commission direct DTE to present seasonal volumetric distribution rates in its next rate case.[2719] Mr. Jester highlighted four bases for this recommendation, including; (1) it would more accurately bill customers for their cost of service; (2) it would help to alleviate an "unfairness" in current rate design; (3) seasonal distribution rates that are higher in the summer will incent customers to adopt energy efficiency measures to reduce summer load, thereby avoiding utility costs; and (4) seasonal distribution rates

[2717] 5 Tr 3900; see also January 23, 2025, order in Case No. U-21534, p. 390.
[2718] 5 Tr 4783.
[2719] 5 Tr 4783.

that are lower in the summer may enable customers to adopt electric heat by making it less costly to operate.[2720]

Mr. Jester focused on DTE's application of a uniform volumetric distribution charge throughout the year; the use of demand to allocate costs of poles, wires, conduit, substations, transformers, and other distribution system equipment; and his assessment that it is incongruous with usage.[2721] He asserted an unfairness in uniform monthly assignment of distribution system costs to residential customers when some customers have electric heat with significantly greater kWh sales than customers that use fossil fueled heat, but have similar summer peak demand – meaning that customers with electric heat overpay their costs of service because they pay a kWh rate based on the average ratio of the annual kWh consumption to summer demand peak.[2722]* He advanced a higher summer rate and lower winter rate to partially mitigate this unfairness.[2723] Mr. Jester also opined that this would enable customers to better control usage and enable customers to adopt electric heat by making it less costly to operate.[2724]

In rebuttal, Mr. Cejas Goyanes and Mr. Willis disagreed with Mr. Jester's proposal. Witness Cejas Goyanes argued that Mr. Jester's proposal provided no technical justification for how energy consumption drives equipment sizing and associated costs for distribution plant and provided no causal explanation for how energy consumption drives equipment sizing and associated costs.[2725] Thus, Mr. Cejas Goyanes argued that

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[2720] 5 Tr 4783-4785.
[2721] 5 Tr 4783-4785.
[2722] 5 Tr 4784.
[2723] 5 Tr 4785.
[2724] 5 Tr 4784-4785.
[2725] 4 Tr 2572-2573; DTE brief, 226-227.

MNC's proposal fails to align with cost causation principles, and contradicts the classification and allocation methods prescribed by NARUC.[2726] Mr. Willis further asserted that Mr. Jester sponsored a nearly identical proposal in the Company's last rate case, Case No. U-21534, which the Commission declined to adopt, stating: "[t]he Commission finds that MNSC's recommendation was not sufficiently detailed in testimony to allow the Company to respond or for the Commission to determine whether such a study would be necessary and beneficial."[2727] Mr. Willis, claimed that there is similarly insufficient detail in MNC's proposal in this case, and requested the Commission again reject the proposal.[2728]

In rebuttal, Staff witness Krause acknowledged MNC's recommendation and expressed no preliminary opposition.[2729] He did, however, express concern over the litany of rate and tariff proposals that are suggested by various parties (MNS, MEIU, CEO) for advanced discussion and inclusion in the Company's next rate case.[2730] To that end, Mr. Krause recommended a time and schedule be considered as part of the current process being discussed to separate cost of service and rate design from rate cases and future cases that may be filed.[2731] Staff did not address this issue in its initial brief.

In rebuttal, ABATE witness Andrews asserted that MNC's proposal related to seasonal distribution rates should only apply to residential customers and should not be construed as a means to change the allocation of distribution costs among the customer

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[2726] 4 Tr 2572-2573.
[2727] 4 Tr 1787-1788; DTE brief, 226.
[2728] 4 Tr 1788.
[2729] 5 Tr 5252.
[2730] 5 Tr 5252-5253.
[2731] 5 Tr 5252-5253.

classes in the COSS.[2732] He argued that any change of distribution rates that affect Primary customers must be studied prior to its implementation and be shown to be reflective of cost-causation principles.[2733] This was reiterated in ABATE's initial brief.[2734]

This PFD appreciates MNC's proposal for seasonal distribution rates. However, this PFD agrees with DTE that more support is necessary for the proposal and recommends the Commission decline to adopt it. Further, should such a recommendation be raised in the future, this PFD suggests that consideration should be given to the complicated nature of benefits and customer behavioral changes that would be necessary to effectuate such a proposal. Even if MNC presents the necessary support identified by the Company to obtain approval of this proposal, this PFD recommends the Commission also require MNC to present its vision for how the Company would implement the customer educational element that will be necessary to prompt customers to make the necessary behavioral changes and see a benefit.

2. Rate Schedule D1.6 Transition and Closure

Company witnesses Willis, Sparks, and Gerdes presented DTE's proposed elimination of Rate Schedule D1.6 and transition of customers to Rate Schedule D1.11. Rate Schedule D1.6 is DTE's Special Low Income Pilot Residential Service Rate and DTE's Rate Schedule D1.11 is DTE's Standard time-of-use (TOU) Residential Service Rate. These witnesses explained that the Company was directed in the U-21534 order to conduct certain analyses relating to the transition from Rate D1.6 to Rate D1.11,

[2732] 4 Tr 3231-3232.
[2733] 4 Tr 3231-3232.
[2734] ABATE brief, 64-65.

including: (1) an analysis of shutoff information, (2) an analysis of factors impacting household ability to shift usage, and (3) a regression analysis.[2735]

For the required shutoff information analysis, Mr. Sparks testified that since the transition has not yet occurred, the Company provided an analysis of disconnect rates pre- and post-TOU implementation. He stated that it "shows very little impact to overall disconnect rates."[2736] He added that the Company will provide further shutoff analysis for D1.6 customers transitioning to D1.11 when a full year of data is available, or in the next rate case filing, whichever is sooner.[2737]

For the required analysis of factors impacting household ability to shift usage, Mr. Gerdes testified that DTE contracted with a vendor who conducted surveys regarding enrollment, dropout, post-cooling, and post-heating behaviors. He explained that the post-cooling and post-heating surveys asked questions about customers' willingness to change behaviors, knowledge and awareness, and technology use and motivations to understand how customers use their appliances and what factors affect their ability to shift appliance use.[2738] These surveys, conducted during the DTE's Advanced Customer Pricing Pilot (ACPP) and including 220,000 customers, tested TOU rates along with an opt-in and opt-out strategy for enrollment, and assessed low-income customers both through usage statistics and survey response.[2739] Mr. Gerdes discussed observations

[2735] 4 Tr 1751, 2528, 2732.
[2736] 4 Tr 2732, Figure 1.
[2737] 4 Tr 2732.
[2738] 4 Tr 2529-2530.
[2739] 4 Tr 2529

and outcomes related to the survey results and concluded that low-income customers both have a desire to shift usage and are capable of doing so.[2740]

As for the regression analysis, Mr. Gerdes testified that he used data from 2022 to test for a correlation between the difference in a customer's D1.6 and D1.11 bill and their electricity use, population density, or the MiEJ Screen Composite score.[2741] Mr. Gerdes concluded from his analysis that the average D1.6 customer represented in the 2022 data would be expected to have a 0.17% lower bill on the D1.11 rate.[2742] He added however, that the while there is a correlation between the difference between a customer's D1.6 and D1.11 bill and the independent variables (kWh usage, population density, and MiEJ Screen Scores), the effect is small.[2743] He also noted that among the variables tested, a customer's usage had the largest impact on the percentage change in bill when comparing D1.6 and D1.11, but that customers did not need to have above average usage in order to have a lower bill on D1.11.[2744]

CEO witness Kentworthy agreed that DTE's plan for communication with customers and its plan to provide materials explaining low-income energy efficiency offerings align with the Commission's expectations for expanded outreach to low-income customers. He also agreed that the Company has begun to implement a rollout that is "directionally consistent with the Commission's outreach expectations."[2745] He was, however, critical of what he considered to be DTE's failure to describe a targeted plan to

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[2740] 4 Tr 2529-2530
[2741] 4 Tr 2533.
[2742] 4 Tr 2536.
[2743] 4 Tr 2536.
[2744] 4 Tr 2537.
[2745] 4 Tr 3635.

promote weatherization and smart-thermostats.[2746] He was also critical of what he considered the Company's failure to present an AMI-analytics plan that flags at-risk households and triggers tailored interventions.[2747] Thus, he asked DTE, in rebuttal, to explain its plan in greater detail and also asked DTE clarify whether, and how, it will go beyond universal mailings to identify specific customers adversely affected by the transition period and how it will leverage advanced meter data and other tools to identify customers demonstrating energy limiting behaviors and intervene.[2748] He also recommended that the Commission direct DTE to identify and assist low-income customers during the D1.6 to D1.11 transition by requiring "AMI-based analytics to flag at-risk households; targeted, multilingual outreach; streamlined enrollment in assistance (e.g., LIA/arrears management); and practical mitigations (e.g., smart-thermostat support, weatherization referrals, safety checks, and near-term bill-protection where warranted)."[2749]

In its initial brief, the CEO recounts its witnesses' testimony and expresses an expectation that DTE discuss the transition and its mitigation measures in its next rate case.[2750] The CEO recommend that the Commission direct DTE to conduct shadow billing of vulnerable transitioning customers and then perform targeted outreach to those customers to mitigate bill impacts.[2751]

[2746] 4 Tr 3633-3634.
[2747] 4 Tr 3634.
[2748] Id.
[2749] 4 Tr 3636-3637.
[2750] CEO brief, 43-45.
[2751] CEO brief, 45.

DAAO witnesses Watts and Nichols also addressed the Company's transition of customers from Rate Schedule D1.6 to D1.11. Ms. Watts testified that she is particularly worried about DTE's TOU pricing because it fails to take into consideration that people have to heat and cool their homes during the most expensive peak period and TOU pricing punishes people who cannot be flexible in their energy usage.[2752] Ms. Nichols asserted that the Commission approved the transition to D.1.11 based on DTE's projection that "nearly two-thirds of low-income customers would experience reduced utility rates," and expressed concern that DTE does not have any plans to track the actual impact after the transition.[2753] She also asserted DTE's ACPP survey results demonstrate that many low-income customers may engage in harmful, "energy-limiting behavior," which she defined as the "inability or unwillingness to consume enough energy to reach a desired level of comfort."[2754] Ms. Nichols explained that the public comments in this case verify that energy-limiting behavior is already commonplace among DTE customers. She testified that in Case No. U-21534, the Commission directed DTE to develop a plan to use smart meter data to identify and address energy-limiting behavior and asserted that the Company, contrary to that directive, indicates that it only intends to provide meter-based information to customers following the transition.[2755]

Ms. Nichols further testified that DTE failed to comply with the U-21534 order regarding mitigating potential price increases for low-income customers transitioning to D1.11 saying that the Company's plan to use mailers and emails containing educational

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[2752] 5 Tr 4168.
[2753]5 Tr 4131.
[2754] 5 Tr 4132-4133; Exhibit DAO-23, p. 3
[2755] 5 Tr 4134-1435.

outreach with information on weatherization and smart thermostats is not sufficient.[2756] She opined that DTE's plan must directly assist low-income customers in weatherizing their homes and installing smart thermostats, and not just provide general information.[2757] Citing the recommendations made by the vendor of the ACPP survey, Ms. Nichols recommended that the Commission: (1) require that DTE track low-income customer bills after the transition to Rate Schedule D1.11 and report this data in its next general rate case in such a form that it will permit analysis of how many low-income customers experienced decreased and increased bills and by how much; (2) require that before its next rate case filing, DTE develop substantive programs beyond mere educational outreach to mitigate energy-limiting behavior and assist low-income customers in weatherizing their homes and installing smart thermostats; and (3) clarify that, before its next rate case filing, DTE must conduct a targeted analysis focusing specifically on factors impacting low-income customers' ability to shift their energy usage to non-peak hours.[2758]

In rebuttal, DAAO witness Jacob recommended that DTE be required to provide additional outreach, support, and financial resources to the one-third of low-income customers that are expected to experience higher bills after transitioning to D1.11.[2759] Further, in support of the DAAO's position that the impact of TOU rates on low-income customers' lives must be better understood and considered by the Commission, she concurred with CEO witness Kenworthy that the Commission require that DTE use AMI-based analytics to flag at-risk households and provide targeted multilingual outreach and

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[2756] 5 Tr 4136-4137.
[2757] 5 Tr 4137.
[2758] 5 Tr 4137-4140.
[2759] 5 Tr 4329.

streamlined enrollment in assistance programs, and offer practical mitigations, such as smart-thermostat support, weatherization referrals, safety checks, and near-term bill-protection where warranted.[2760]

While Ms. Jacob disagreed with Mr. Kenworthy's opinion that DTE's actions align with the Commission's directive for expanded outreach to low-income customers, she testified that far greater financial investments in whole-home weatherization for low-income households are needed, in addition to the following: (1) increased partnerships with trusted community messengers to share accessible information with residents and clarify confusion regarding the transition; (2) greater investments in energy efficient appliances for low-income household; and (3) other equity-centered actions by DTE to ensure the transition to D1.11 does not place unfair burdens on low-income customers.[2761]

In briefing, the DAAO repeat and elaborate upon the testimony of its witnesses, emphasizing that in Case No. U-21534, when the Commission approved the transition to Rate D1.6, it ordered DTE to do three things: (1) perform specified analyses of the new rates; (2) address potentially dangerous energy-limiting behavior; and (3) implement cost mitigation measures for low-income consumers who would suffer from higher rates under the new schedule.[2762] The DAAO argue that DTE has failed to properly perform its duties under these mandates.[2763] Therefore, the DAAO argue that the Commission should require the Company to allow those low-income customers who wish to remain on or

[2760] 5 Tr 4329-4331.
[2761] 5 Tr 4331.
[2762] DAAO brief, 79-80.
[2763] DAAO brief, 80-83.

transition back to a flat rate to do so.[2764] Further, the DAAO contend that because DTE is failing to address the second mandate, that is to address energy-limiting behavior, the Commission should reaffirm its order and halt the transition to time-of-use rates until the Company establishes a system to properly identify and address energy-limiting behavior that is detrimental to health and safety.[2765]

The DAAO also recommend that the Commission require DTE to take two other measures beyond those already ordered: (1) require DTE to track customer bills after the transition; and (2) require DTE to analyze the non-monetary consequences of the rate schedule transition for low-income customers and provide support to counteract these consequences.[2766]

In rebuttal, Mr. Willis addressed the criticisms of the CEO and the DAAO. In response to Mr. Kenworthy's recommendations, Mr. Willis highlighted specific educational and program outreach efforts being utilized by DTE for all transitioning customers and further highlighted the development of DTE's approach to leverage AMI data for transitioning customers to further assist them in understanding available efficiency programs and how they use energy.[2767] He asserted that there is no gap in the Company's actions regarding AMI relative to the Commission's directive.[2768] Mr. Willis reiterated that DTE does not interpret the Commission's order to encompass "near term bill protection" or the other things highlighted by Mr. Kenworthy and argued that the

[2764] DAAO brief, 80.
[2765] DAAO brief, 83-86.
[2766] DAAO brief, 87-89.
[2767] 4 Tr 1784.
[2768] Id.

Company does need not to provide additional LIA enrollment support for transitioning customers since they are already receiving the LIA credit on the D1.6 rate.[2769]

Mr. Willis further testified that DTE does not agree with the DAAO witness Nichols's recommendations, and they should be rejected. He asserted that it is not necessary or effective to track customer bills because: (1) a customer's electric use changes over time, particularly due to weather, such that the impact of the D1.11 rate is marginal and not a standalone factor determining the total amount of a customer's bill; (2) DTE transitioned nearly two million customers to D1.11 in 2023, including 95,000 low-income customers, and is not aware of any systemic bill impacts; and (3) of the approximately 27,000 customers that will transition to D1.11 in October, about 5,800 were previously on D1.11 prior to switching.[2770] He also noted that customers transitioning to D1.11 may choose any other residential base rate, including D1.2, D1.8, and D1.13, based on what is most effective for their needs.[2771]

Overall, Mr. Willis noted that in Case No. U-21534, the Commission's directives related to the approximately one-third of customers in DTE's prior analysis who may experience higher rates because of the transition.[2772] He asserted that the Company has "developed enhanced materials" that will be sent to all transitioning customers, that include explanations of the rate, the time of use prices themselves, and additional details about EWR programs, including links, for both income-qualified and broad-based

[2769] 4 Tr 1785.
[2770] 4 Tr 1779-1780.
[2771] 4 Tr 1780.
[2772] Id.

programs.[2773] He noted that the materials contain a broader set of tools and information than was provided to the low-income customers who transitioned from D1.11 in 2023.[2774]

Additionally, Mr. Willis testified that the 298-page final report on the ACPP, which was used to develop successful outreach during the transition in 2023, contained extensive analytics and included more than 2,000 randomly selected low-income customers as part of its "robust" statistical design.[2775] He asserted that the surveys asked questions that directly addressed customers' ability to shift usage.[2776] Mr. Willis also referred to Mr. Gerdes' regression analysis and Mr. Sparks' testimony on a shutoff analysis and posited that the Company has already completed extensive studies and analyses such that no "more targeted analysis" should be required.[2777]

In briefing, DTE generally reiterates its witnesses' testimony and argues that its existing measures and analyses are both sufficient and effective in ensuring a fair and informed transition for all customers.[2778]

As noted above, the order in Case No. U-21534 required DTE to conduct three analyses: (1) an analysis of shutoff information, (2) an analysis of the factors impacting household ability to shift usage, and (3) a regression analysis. This PFD agrees with the DAAO that DTE has not sufficiently analyzed the factors impacting household ability to shift usage. DTE's use of previous surveys that were not designed specifically to address this directive are insufficient. This PDF notes that DTE did not provide an analysis of

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[2773] 4 Tr 1781.
[2774] Id.
[2775] Id.
[2776] 4 Tr 1781-1782
[2777] 4 Tr 1782.
[2778] DTE brief, 229-230.

shutoff information, but the Company asserts that it will provide the analysis either when a full year of data is available or in the next rate case. This PFD also notes that none of the parties objected to the sufficiency DTE's regression analysis. Therefore, this PFD recommends that the Commission direct DTE to conduct an updated analysis specifically designed to analyze the factors impacting low-income customers' ability to shift usage and provide the analysis in its next rate case. Further, this PFD recommends that the Commission emphasize to the Company that it expects to receive a shutoff analysis as soon as feasible, but not later than the Company's next rate case.

Turning to the one third of customers who may experience higher utility rates because of the D1.6 to D1.11 transition, the Commission required DTE to implement the CEOs' recommended mitigation measures including expanded educational outreach to low-income customers regarding low-income energy efficiency programs, weatherization, and smart thermostats. This PFD agrees with the CEO that DTE failed to describe a targeted plan to promote weatherization and smart thermostats. However, this PFD disagrees with the DAAO that the Commission's order required DTE to develop substantive programs beyond mere educational outreach. Therefore, this PFD recommends that the Commission order DTE to update and modify its educational outreach to transitioning low-income customers to ensure it includes substantive information about weatherization and smart meters.

As for the directive that DTE use AMI data to identify customers and address energy-limiting behavior, this PFD finds DTE did not present a plan to accomplish this directive and the Company's explanation that it is developing an approach is insufficient. This PFD adopts the CEO's recommendation that the Commission require DTE to

identify and assist low-income customers during the D1.6 to D1.11 transition by requiring AMI-based analytics to flag at-risk households; targeted, multilingual outreach; streamlined enrollment in assistance (e.g., LIA/arrears management); and practical mitigations (e.g., smart thermostat support, weatherization referrals, safety checks, and near term bill protection where warranted).

Further, this PFD finds it reasonable that the Commission require DTE to discuss the transition and its mitigation measures in its next rate case, including conducting shadow billing of vulnerable transitioning customers and targeted outreach to those customers to address bill impacts. The Commission should also require that DTE track low-income customer bills after the transition and report this data in its next rate case in such a form that it will permit analysis of how many low-income customers experienced decreased and increased bills and by how much.

3. Rate D1.1 - Demand Response AC Direct Load Control

Mr. Leuker presented testimony regarding the Company's CoolCurrents Program – the Company's Interruptible Space Conditioning tariff (Rate D1.1) that is available to residential and commercial customers. Customers who are enrolled in this program are provided with a direct load control device (LCD) on their air conditioning units or central heat pump that allows the Company to cycle the associated appliance in exchange for a discounted rate.[2779]

Staff witness Isakson, after discussing Consumers' device cycling program, proposed that DTE develop a discount that can be applied to Rate D1.1 power supply

[2779] 3 Tr 1350-1352.

charges that reflects the value of the interruptible resource.[2780] He indicated that Staff would like to see a rate design in the future that designs charges for Rate D1.1 that match power supply rates for other residential customers, and update the discount applied to those rates independently from base rates.[2781] Mr. Isakson reasoned that this method would make the benefits and costs of the DR resource easier to determine and make the discount identifiable. Staff therefore recommended that the Commission direct the Company to provide the data necessary to develop an explicitly calculated discount for Rate D1.1 power supply rates that reflects the value provided by interruptible load in its next rate case.[2782]

In briefing, Staff explained that Residential Rate D1.1, the Company's interruptible space-conditioning rate that applies to separately metered air conditioning load, differs from the standard residential service rate because Rate D1.1 has a reduced monthly service charge and a discounted power supply charge that does not vary by season or time of day.[2783] The discounts afforded to Rate D1.1 are meant to reflect the interruptible nature of the service.[2784] Further, this requires an extra meter but not an additional service drop or other customer-related costs.[2785] Staff noted that all residential power supply rates are calculated by allocating the class's revenue requirement to each rate based on present revenue.[2786]

[2780] 5 Tr 4910-4912.
[2781] 5 Tr 4912.
[2782] 5 Tr 4912.
[2783] Staff brief, 177; 5 Tr 4909.
[2784] Staff brief, 177; 5 Tr 4909.
[2785] Staff brief,177-178; 5 Tr 4909.
[2786] Staff brief, 178; 5 Tr 4910

Staff also argued that this method is inappropriate for rate D1.1 because it is a DR rate that provides a benefit to all power supply customers.[2787] Staff asserted that the benefit of interrupting D1.1 customers' load during peak times can and should be quantified and used to determine an appropriate discount.[2788] Citing to its support for Consumers' similar interruptible air conditioning program, which provides customers with a $5 bill credit per summer month, Staff argued that Consumers' method quantifies the value of offsetting power supply costs by multiplying locational marginal price estimates times expected load reductions; thus, tying the customer's bill credit directly to the value of actual load reductions.[2789] Because basing the discount on actual performance data reflects the actual purpose of Rate D1.1, which is to reduce costs for all power supply customers, Staff recommended that the Company develop a new discount for Rate D1.1 that reflects the actual cost savings produced by interruptible customers.[2790] Finally, Staff noted that decoupling charges from present revenue by rate would make the cost-benefit analysis for this DR resource easier to determine by making the discount explicitly tied to a measure of cost savings, rather than an implied measure based on years of self-perpetuating rate designs.[2791]

Neither DTE nor any other party responded to this recommendation in rebuttal or in briefing and, therefore, this PFD recommends the Commission adopt Staff's recommendation.

4. Rate D8 -- Non-interruption fee adder

[2787] Staff brief, 178.
[2788] Staff brief, 178; 5 Tr 4910-4911.
[2789] Staff brief, 178; 5 Tr 4911.
[2790] Staff brief, 178.
[2791] Staff brief, 178; 5 Tr 4912.

Like the Company's Rate D1.1 rate design, no party objected to the rate design of Rate D8, another interruptible customer rate. Mr. Isakson, however, made recommendations for revisions to the interruptible adder fee associated with the Company's Rate D8. Like Rate D1.1, Rate D8 is also an interruptible supply DR rate but operates in a different way. Rather than allowing the Company to directly interrupt the customer's load, the Company, instead, requests the customer reduce their load under certain conditions.[2792] Customers on Rate D8 may avoid interruption by paying for the cost of replacement energy plus $0.00576 per kWh, plus the appropriate voltage level charge.[2793] Mr. Isakson explained that while the voltage level charges are updated through the normal course of rate design process, the non-interruptible fee adder is not regularly updated and has been the same since 2003.[2794] Thus, Staff recommends that the non-interruption fee for Rate D8, not including voltage charges, be updated for inflation using the Bureau of Labor Statistics inflation calculator for the period between January 2009 and June 2025, which would result in a new fee of $0.00880 (to be presented in the Company's next rate case).[2795] To avoid rate shock, however, Staff recommends increasing the charge by only 50% of full 2025 level by setting the non-interruption fee to $0.00728 in this case and increasing the Rate D8 non-interruption fee to $0.00880 in DTE's next rate case.[2796] Staff's reiterated its recommendation in its initial brief.[2797]

[2792] 5 Tr 4912.
[2793] 5 Tr 4912.
[2794] 5 Tr 4913.
[2795] 5 Tr. 4913.
[2796] 5 Tr 4913.
[2797] Staff brief, 179-180.

Neither DTE nor any other party responded to this recommendation in rebuttal or in briefing and, therefore, this PFD recommends the Commission adopt the recommendation to reset the non-interruption fee discussed above.

B. Commercial Secondary and Primary Rate Design

Company witness Turner addressed proposed changes to rate design for certain commercial secondary and primary rate schedules, and sponsored Exhibit A-16, Schedule F3 setting forth the current and proposed rate design, along with the corresponding revenue by rate schedule based on the billing determinants for the test year.[2798] Mr. Turner testified that the only exceptions to the rate design structure are for the Company's commercial and primary TOU rates, as recently approved in Case No. U-21534.

In briefing, the Company generally explained the bases for its rate design.[2799] The Company explained that the rate design for commercial TOU Rate Schedule D3.11 and primary TOU Rate Schedule D14 are designed to be revenue neutral to the proposed D3 and D11 Rate Schedules, respectively.[2800] The Company explained that the Commission, in its December 1, 2023, order in Case No. U-21297, directed the Company to maintain the current ratio between power supply demand and energy rates for Rate Schedules D4, D6.2 and D11, and further explained that this approach was intended to mitigate the impacts of volatility in the capacity and non-capacity allocations and the resulting volatility in the overall ratio of demand and energy-based rates.[2801] The

[2798] 4 Tr 2583; DTE brief, 230.
[2799] DTE brief, 230-231.
[2800] DTE brief, 231; 4 Tr 2584.
[2801] DTE brief, 231.

Company noted that power supply capacity revenue has historically been collected entirely through demand charges on these rate schedules; however, it argued that, in this case, the capacity revenue requirements for these rate schedules exceeded the current demand share of the present demand to energy ratios.[2802] Thus, as discussed below, the Company proposed in this case that a portion of the capacity costs be recovered on a volumetric basis on the relevant rate schedules in order to " maintain alignment with the allocations of capacity and non-capacity costs and also maintain designing power supply rates such that the present ratio recovered via demand versus energy rates is held constant, which aligns with the rate design methodology established in Case Nos. U-21297 and U-21534."[2803]

1. Commercial Secondary Rate Design

Mr. Turner provided a description of each of the Company's commercial secondary rate schedules.[2804] He explained that the proposed commercial secondary power supply and distribution charges were designed to meet their respective deficiencies shown in Mr. Cejas Goyanes' Exhibit A-16, Schedule F1.1, page 2 (for power supply) and Exhibit A-16, Schedule F1.2, page 1 (for distribution).[2805] According to Mr. Turner, the proposed power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Mr. Cejas Goyanes' Exhibit A-16, Schedule F1.5, which shows how much of the power supply revenue requirement for each rate class is related to capacity and non-capacity costs.[2806]

[2802] DTE brief, 231.
[2803] DTE brief, 231; 4 Tr 2585-2586.
[2804] 4 Tr 2586-2587; Exhibit A-16, Schedule F3.
[2805] 4 Tr 2587.
[2806] 4 Tr 2587.

Mr. Turner explained that power supply revenue targets were allocated using the same methodology utilized in Case No. U-21534 to allocate both the capacity and non-capacity power supply revenue requirements to the individual rate schedules within the secondary class.[2807] He also explained how commercial secondary energy rates were determined. He noted that, with the exception of Rate Schedules D3.5 and D4, all commercial secondary power supply rates are energy based.[2808] Thus, after allocating revenue requirements to each individual rate schedule, the capacity and non-capacity targets for each rate schedule were used to determine the capacity and non-capacity energy rates.[2809] Mr. Turner then explained that the rate structure for Rate Schedule D3.5 Company Owned EV Charging Service Pilot has a non-capacity energy charge based on time of use and a session fee which includes power supply capacity and is based on the demand rating of the charging station consistent with the approved rate design in Case No. U21534.[2810] Finally, Consistent with rates approved in Case Nos. U-21297 and U-21534, Mr. Turner explained that the rate structure for Rate Schedule D4 Large General Service Rate was designed to maintain the existing ratio between demand and energy charges, which is 53% demand and 47% energy.[2811] DTE reiterated this testimony in support of its commercial secondary rate design.[2812]

Mr. Isakson testified that Staff does not object to the Company's commercial secondary rate design, and Staff did not address this issue in briefing.[2813] No other party

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[2807] 4 Tr 2588.
[2808] 4 Tr 2588.
[2809] 4 Tr 2588.
[2810] 4 Tr 2588.
[2811] 4 Tr 2588-2589.
[2812] DTE brief, pp. 231-232.
[2813] 5 Tr 4904.

addressed this rate design in testimony or briefs. Thus, this PFD recommends approval of DTE's commercial secondary rate design.

2. Rate D3 - EV Fast Charger Rate

Rate Schedule D3 is the Company's general service rate for non-residential customers.[2814] Mr. Krause provided a history of the Demand Charge Holiday addressed in Commission orders in Case Nos. U-20162, U-21297, and U-21534, which is currently scheduled to sunset on June 1, 2028.[2815] Although Staff did not recommend a change in the demand charge holiday, Staff did recommend removal of the two-year rolling provision from the currently approved holiday and further recommended that the June 1, 2028 sunset date established in Case No U-21534 be firm for the demand charge holiday.[2816] Mr. Krause explained that Staff made this recommendation "because charging stations on rate D3 with a demand above 1000 kW are receiving subsidy and that subsidy should be discontinued."[2817] Additionally, Mr. Krause recommended that the Company propose a new tariff for fast charging (DCFC) in its next rate case based on available fast charging data.[2818] Staff recommended that the proposal for a new tariff: (1) be based on cost of service; and (2) be an energy only rate, with no demand charges.[2819] Staff also recommended that DTE provide rate design options that consider charging station uptime and charging reliability.[2820]

[2814] 4 Tr 2586.
[2815] 5 Tr 5246.
[2816] 5 Tr 5246.
[2817] 5 Tr 5246.
[2818] 5 Tr 5247.
[2819] 5 Tr 5247.
[2820] 5 Tr 5247.

In rebuttal, MEIU witness Schuster also gave a detailed history of the demand charge holiday currently in effect and directives of the Commission related to the sunset of the demand charge holiday.[2821] Ms. Schuster did not fully agree with Staff's assessment that EV charging station operators that exceed 1000kW in demand on Rate Schedule D3 (and, thus, their paying customers) are receiving a subsidy, particularly in the context of EV-derived revenues in the aggregate.[2822] She testified that there is "mounting evidence that load from EV charging customers as a whole contributes much less to system peaks when compared to other commercial and industrial customers, and that the revenue attributable to EV charging exceeds the cost of service over time."[2823] Thus, she opined that EV charging customers may actually be subsidizing rates of utility customers who do not own EVs or use EV charging, testifying that "[n]arrowly focusing on DCFC without considering the overall contribution of EV load to DTE's system and system revenues is short-sighted and risks undermining broader EV adoption (and revenue contribution) goals."[2824] Ms. Schuster disagreed with Staff's recommendation to remove the two-year rolling demand charge waiver and recommendation that the Company propose a DCFC-specific tariff in its next rate case.[2825]

Citing failure of EV adoption to reach a steady state to inform the Company of an appropriate DCFC tariff, and the lack of stakeholder engagement regarding the development of a successor rate, Ms. Schuster recommended rejection of Staff's recommendation to remove the two-year rolling waiver provision for DCFC stations

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[2821] 5 Tr 3997-4000.
[2822] 5 Tr 4000-4001.
[2823] 5 Tr 4001.
[2824] 5 Tr 4001.
[2825] 5 Tr 4002-4007.

energized after June 2026 and Staff's recommendation that the Company create a DCFC tariff in its next rate case. She further recommended the Commission require the Company to: (1) conduct a comprehensive evaluation of best practices as it relates to DCFC tariffs being implemented in other states and countries; (2) conduct a stakeholder meeting to gather key stakeholder and industry feedback; and (3) require the Company to present its findings and propose a long-term plan for the eventual implementation of an appropriate DCFC tariff.[2826]

Similar to MEIU, Walmart witness Lyon recommends that the Commission "direct the Company to plan, develop, and announce a stakeholder convening agenda and schedule as soon as is prudent to allow for sufficient opportunity and time to develop a consensus-based EV fast charging rate proposal to present to the Commission no later than December 1, 2026."[2827]

MEIU and Walmart reiterate the recommendations of their witnesses in their respective briefs.[2828]

In its initial brief, Staff rejects MEIU's and Walmart's recommendations. In response to the suggestion that a track record for market stability or steady state usage should be established before a fast charging tariff is adopted, Staff notes that this recommendation is without merit because Staff is currently working on implementing tariffs for large users based on potential data centers, which does not currently have stability in the data center market – thus, this is not a standard that should be adopted.[2829]

[2826] 5 Tr 2005-2007.
[2827] 5 Tr 4099.
[2828] MEIU brief, 18-22; Walmart brief, 9-10.
[2829] Staff brief, 195-196.

Further, Staff observes that the end of the demand charge holiday does not necessarily have to coincide with the implementation of a new fast charging tariff, that fast charging customers with demand over 1,000 kW could be moved from Rate D3 to Rate D4 when the demand charge holiday ends, and that there would not necessarily be a new fast charging rate at that time.[2830] Finally, Staff expressed a lack of confidence that discussions with interested parties will lead to a consensus tariff.[2831] Thus, Staff reiterates its recommendations that demand charge holiday firmly conclude on June 1, 2026, and that any proposed future rate be based on cost to serve; however, Staff said that "other elements of the rate can be open to further discussion."[2832]

In its initial brief, DTE asserts that the order in Case No. U-21534 already establishes a clear path to a successor EV fast charger rate, directing the Company to file a new rate design by December 1, 2026—after robust stakeholder engagement—so that approval and implementation occur well ahead of the June 2028 conclusion of the demand charge holiday.[2833] The Company states that is committed to meeting this timeline and collaborating with Staff and other interested parties.[2834] Thus, DTE agrees that the resulting rate should be grounded in cost-of-service principles, with considerations such as uptime and reliability appropriately vetted through the stakeholder process and addressed in the subsequent filing, rather than set as predetermined criteria.[2835] The Company also asserts that Walmart witness Lyon's proposal aligns with

[2830] Staff brief, 196.
[2831] Staff brief, 196.
[2832] Staff brief, 196.
[2833] DTE brief, 233.
[2834] DTE's Initial Brief, p. 233.
[2835] DTE's Initial Brief, p. 233.

this framework and further maintains that engagement with interested parties prior to the December 2026 filing is already provided for and is the proper forum to evaluate design. Accordingly, no further action is needed from the Commission.[2836]

This PFD agrees with Staff's proposals and finds that they align with the plans for the DCFC tariff set forth in Case No U-21534. For the reasons articulated by Staff, this PFD does not agree that a track record for market stability or steady state usage should be established before a fast-charging tariff is adopted as suggested by MEIU. Noting DTE's acknowledgement that many of the interests of Staff and the Intervenors are already built into the plans for the EV DCFC charging tariff, as set forth in the U-21534 order, this PFD finds that, aside from adopting the recommendations of Staff and reiterating the need to follow the directives of the Commission in its order in Case No. U-21534, no additional direction is necessary from the Commission at this time.

3. Rate D11 -- Commercial and Industrial Primary Rate Design

Mr. Turner provided information regarding the Company's primary customer rate schedules and proposed a rate design for primary power supply rates that maintains the currently approved ratio between demand and energy revenues.[2837] As Mr. Turner explained in his direct testimony, the Commission, in its December 1, 2023 order in Case No. U-21297, directed DTE to maintain the current ratio between power supply demand and energy rates for Rate Schedules D4, D6.2, and D11, saying, "the current ratio between demand and energy charges for Rate Schedule D4, D6.2, and D11 should be maintained . . . ."[2838] This rate design was again approved by the Commission in Case

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[2836] DTE's Initial Brief, p. 233; 4 Tr 1790-1791.
[2837] 4 Tr 2590-2597.
[2838] 4 Tr 2584 (citation omitted).

No. U-21534.[2839] Mr. Turner explained that this approach was intended to mitigate the impacts of volatility in the capacity and non-capacity allocation and the resulting volatility in the overall ratio of demand- and energy-based rates and asserted that the ratio considers total power supply revenues (i.e. both capacity and non-capacity revenues).[2840] Thus, the Company (and Staff) utilized this Commission-approved method for determining demand and energy charges for Rate D11 customers (and other primary customers with demand charges) with 47% of present power supply revenues for relevant primary customers coming from demand charges, and the remaining 53% coming from energy charges.[2841] Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission, or transmission voltage.[2842] Mr. Turner did not propose changes to the primary rate service charges and did not propose any new primary rate schedules.[2843]

ABATE witness Andrews agreed that DTE's primary customer class rate design is consistent with the order in Case No. U-21297, and agreed that the establishment of a fixed 47/53 ratio was intended to address rate case to rate case volatility in the SRM capacity charge that is related to the annual true up of that charge.[2844]

Mr. Andrews discussed two constraints in DTE's primary customer class rate design: (1) consistent with historical methodologies, the SRM capacity charge is used to determine the split between power supply capacity charges and power supply non-

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[2839] 4 Tr 2586.
[2840] 4 Tr 2584-2585.
[2841] 4 Tr 2584-2586
[2842] 4 Tr 2590-2591.
[2843] 4 Tr 2596-2597.
[2844] 4 Tr 3212.

capacity charges; and (2) the continued volatility of the SRM capacity charges is creating a new issue that current fixed 47/53 split cannot reasonably solve. Mr. Andrews explained that DTE has proposed for the first time in this case to implement a power supply capacity energy charge, and to zero out the power supply non-capacity demand charge because the high SRM capacity charge, which suggests 68% of the power supply revenue requirement is capacity related, is subject to the fixed 47/53 energy split.[2845]

In support of this recommendation, Mr. Andrews expressed concern over fluctuations in the amount of revenue collected through power supply capacity charges and the power supply non-capacity-related charges that occur when SRM capacity charges increase and decrease. He testified that the volatility in the SRM capacity charge can cause "significant" swings in the split of the capacity-related power supply charge and non-capacity-related charge of the primary customer rates and negatively impact the split between total (capacity plus non-capacity) power supply demand charges and total power supply energy charges (currently only non-capacity) which, he asserts, "should not be impacted by the split of power supply capacity costs and power supply non-capacity costs."[2846] He also pointed out that the use of DTE's SRM capacity charge as the basis for apportionment of total production facility costs between demand and energy charges that result in the "very large swing" in apportionment of the total facility cost for a customer class between demand and energy charges for that class violates the principle of rate stability in ratemaking and mitigation of rate shock for customers.[2847] Further, he averred that it failed to consider that all production facility costs are fixed costs that are not driven

[2845] 4 Tr 3212.
[2846] 4 Tr 3213.
[2847] 4 Tr 3214.

by energy consumption, and asserted that all of the fixed production facility costs that are allocated to a customer class should be recovered through demand charges to the extent demand charges are used to recover costs for that customer class – and regardless of the allocator used to allocate those costs to the customer classes.[2848]

Thus, Mr. Andrews recommended that, for D11 primary customer rates with both demand and energy charges, 63% of power supply costs should be recovered through demand charges and 37% through energy charges, based on the Company's 2025 power supply cost components. He testified that transmission costs should be recovered through the non-capacity demand charge, with the remainder of the fixed costs included in the capacity demand charge and that the remaining 37% of power supply revenues would be recovered through the non-capacity energy charge.[2849]

Kroger witness Bieber responded to Mr. Andrews's testimony regarding the history and concerns related to the current 47/53 split between demand and energy revenue allocation for the primary rate schedule.[2850] Although Mr. Bieber expressed some shared concern over the current rate design, he noted that rate designs with higher demand charges and lower energy charges, such as those suggested by ABATE, are favorable to customers with higher load factors, all else being equal.[2851] Mr. Bieber also expressed concern that adoption of ABATE's recommended primary rate design would result in the third of three different rate design methodologies in a span of just three rate cases.[2852] He did not support ABATE's proposal and explained that frequent and significant

[2848] 4 Tr 3213-3214.
[2849] 4 Tr 3218-3219.
[2850] 5 Tr 4444-4452
[2851] 5 Tr 4450.
[2852] 5 Tr 4453.

deviation from the underlying methodology was troubling in light of the fact that such changes" consistently align with conditions that favor one subset of customers over another."[2853]

In its initial brief, Kroger suggested that it would be reasonable for the Commission to approve DTE's recommended methodology.[2854] However, Kroger added that, if the Commission were to agree with ABATE that another rate design is appropriate, the Commission may want to consider an update to the calculation of the demand/energy ratio and also proposed inclusion of present revenue derived from the non-capacity power supply on-peak charge premium.[2855] Kroger defined the on-peak premium as the difference between on- and off-peak energy charges for non-capacity power supply on Rate D11 ($0.01 per kWh) times the present on-peak energy sales.[2856] Kroger asserts that the premium paid for on-peak energy can be considered demand-related and, thus, appropriate to include in setting the demand/energy charge ratio.[2857] The result of Kroger's proposed method is a ratio of 51% demand and 49% energy, as compared to the currently approved ratio of 47% demand and 53% energy.[2858]

Ultimately, Kroger recommends that the Commission carefully consider any further changes to the primary rate design methodology and only approve a new rate design if it determines that an alternative method "is both aligned with cost causation and is superior to the existing methodology for consistent use going forward."[2859]

[2853] 5 Tr 4453.
[2854] Kroger brief, 5.
[2855] Kroger brief, 5; 5 Tr 4456.
[2856] Kroger brief, 5-6; 5 Tr 4454-4455.
[2857] Kroger brief, 6; 5 Tr 4454-4455/
[2858] 5 Tr 4457.
[2859] Kroger brief, 6; 5 Tr 4454.

In its initial brief, the Company reiterates its disagreement with ABATE, arguing that the current methodology for determining the power supply demand/energy split for primary rates, approved by the Commission in Case No. U-21297 was supported by Staff and ABATE in that case.[2860] DTE avers that although ABATE also proposed the same alternative methodology in Case No. U-21297 that it is proposing in this case, the Commission declined to adopt it.[2861] DTE argues that "there is no compelling reason to depart from the established and Commission-approved methodology for the demand/energy split."[2862] Additionally, with respect to ABATE's argument regarding the impacts of the SRM capacity charge, DTE argues that Mr. Andrews "incorrectly conflates the allocation of revenue requirements between capacity and non-capacity power supply with the method for splitting power supply revenue between demand and energy charges," stating that "[t]he Company's proposed rates maintain the existing ratio between demand and energy charges, so changes in the SRM capacity charge or the allocation between capacity and non-capacity revenue do not affect the demand/energy charge split."[2863] The Company also alleges that Mr. Andrews improperly opted to reclassify power supply costs based on "his own assessment of which costs were fixed versus variable."[2864] Thus, the Company urges the Commission to reject ABATE's proposal.

Staff acknowledges that, in evaluating the primary power supply rate design, the two issues—large swings between capacity and non-capacity revenue requirements and

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[2860] DTE brief, p. 234
[2861] DTE brief, p. 235.
[2862] 4 Tr 2602-2603; DTE brief, p. 235.
[2863] DTE brief, 235.
[2864] DTE brief, 235.

the ratio between demand and energy revenue requirements—are related. Staff recounts the basis for the existing primary class witness stating:

> In cases prior to U-21297 the former determined the latter, so the ratio of capacity to non-capacity revenue was used to set the ratio of demand to energy revenue. (5 TR 4447-4449.) However, beginning in MPSC Case No. U-21297 the volatility between capacity and non-capacity revenue requirement made it so that it was no longer appropriate to rely on that ratio to set the demand/energy ratio. (Andrews, 4 TR 3215, Figure 2, 5 TR 4449.) Thus, in Case U-21297 the Commission approved Staff and ABATE's proposal to set the demand/energy charge ratio to the ratio approved in the previous case. (Turner, 4 TR 2604.) In re DTE Electric's 2023 Rate Case, MPSC Case No. U- 182 21297, 12/1/2023 Order, pp. 323-328. The Commission made the same determination in the Company's next rate case U-21534. (Turner, 4 TR 2604.) *In re DTE Electric's 2024 Rate Case*, MPSC Case No. U-21534, 1/23/2025 Order, p. 380.[2865]

Although Staff agrees with ABATE's argument that the SRM charge method to determine capacity and non-capacity revenue requirements can have a volatile effect on rate design, in rebuttal, Staff witness Isakson disagreed with ABATE's assertion that "all fixed production facility costs that are allocated to a customer class should be recovered through demand charges to the extent that demand charged are used to recover costs for that customer class and regardless of the allocator used to allocate those costs to the customer classes."[2866] Staff characterizes this method of determining power supply demand and energy charges as "unorthodox," because ABATE proposes to determine power supply costs as either fixed or variable and to then recover all fixed costs via demand charges and variable costs via energy charges.[2867] Staff notes that ABATE considers total fuel costs less transmission, purchased power less purchased capacity, and total O&M expense less total labor costs to all be variable (i.e., they vary with the

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[2865] Staff brief, 181-182,
[2866] 5 Tr 4920; 4 Tr 3217-3220.
[2867] Staff's Initial Brief, pp. 182-183; 4 Tr 3217-3218.

energy used by customers) and therefore all other production costs are fixed.[2868] Thus, Staff observes that ABATE's method suggests that 63% of power supply costs are fixed, with the remaining 37% are variable, which is the same proposal ABATE made in Case No. U-21297.[2869]

As a result, Staff agrees with the Company's argument on a number of issues, including: (1) ABATE incorrectly conflates the allocation of revenue requirements between capacity and non-capacity with the split between demand and energy charges because "the Commission has already fixed the demand/energy ratio to a historic amount, so technically the two issues are currently separated;"[2870] (2) the Company's opposition to ABATE's fixed/variable method is correct, noting "[t]he Company shows that ABATE's method results in a large under collection of capacity revenue and an over collection of non-capacity revenue," which "creates a mismatch between how costs are allocated between capacity and non-capacity in the cost of service study and how they are collected via rate design;"[2871] and (3) ABATE's method represents a significant departure from established cost of service methods previously approved by the Commission.

Staff further explains its opposition to ABATE's proposal pointing out that the cost of service study functionalizes, classifies, and allocates costs, but it does not deem those costs as fixed or variable.[2872] Staff states that the Commission recognizes that a portion of power supply costs, namely production plant, should be allocated to energy, which means that some of the costs that ABATE considers fixed and, thus, only recoverable via

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[2868] Staff's Initial Brief, pp. 182-183.
[2869] Staff's Initial Brief, p. 183.
[2870] Staff's Initial Brief, p. 183.
[2871] Staff brief, 183-184.
[2872] Staff brief, 184; 5 Tr 4920.

demand charges, are currently allocated to energy.[2873] Staff further notes that costs are rarely ever fixed in the long run, so it is inappropriate to set rates as if they were.[2874]

Staff also disagrees with Kroger's proposal to include on-peak premium revenue in the demand/energy ratio calculation because Kroger's assumption implies that noncapacity energy charges can be construed as capacity demand-related capacity costs.[2875] Finally, Staff does "not recommend the Commission approve Kroger's proposal to include on-peak premium non-capacity energy revenue to calculate demand and energy charges, nor the more appropriate application of Kroger's argument by creating on- and off-peak capacity energy charges."[2876] Staff explains that the primary issue in establishing the demand/energy ratio is the large difference between forecasted and actual energy market sales and their reconciliation has downstream effects on rate design; thus, Staff argues that, "fixing the root problem will solve the issue of rate design ratios without necessitating new methods of rate design."[2877] For these reasons Staff recommends rejection of Kroger's proposal.

Mr. Turner reiterated that, under the current Commission-approved framework—reaffirmed in Case No. U-21534—Rate Schedule D11 is designed to maintain the proportional relationship between demand-based and energy-based power supply revenue recovery found in present rates while recovering the full power supply capacity revenue requirement through capacity charges and full power supply non-capacity requirement through non-capacity charges. Thus, the Company is proposing to introduce

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[2873] Staff brief, 184; 5 Tr 4920-4921.
[2874] Staff brief, 184.
[2875] Staff brief, 185.
[2876] Staff brief, 186.
[2877] Staff brief, p. 186.

a capacity energy charge to maintain this relationship. As such DTE argues that no further action is needed from the Commission as to this matter.

This PFD recognizes the challenges that arise in designing primary power supply rates and appreciates ABATE's and Kroger's efforts to find a resolution for those challenges. This PFD, however, notes that the current rate design is consistent with the most recent Commission orders and directives and is not persuaded that the approaches of ABATE and Kroger in seeking approval of a re-design are appropriate at this time. Further, this PFD acknowledges the Commission's choice to decline ABATE's proposal in Case No. U-21297, which essentially mirrors that proposed in this case, and finds that ABATE has not presented any distinguishing facts or circumstances in this case that would prompt a recommendation for change. This PFD agrees with Staff when it proposed, "[i]f the Commission approves Staff's proposal to enhance the forecast of energy market sales and thus dampen the large swings in revenue requirements created by reconciling the forecast to actuals, then perhaps in future rate cases it will be appropriate to revert to the previous method of allowing the capacity and noncapacity revenue requirements to inform the ratio of demand and energy charges." Thus, this PFD finds that the currently approved method for designing primary power supply rates is the most appropriate at this time and this PFD recommends approval of the Company's primary power supply rate design.

4. Rate Schedule D3.5

Mr. Turner identified Rate Schedule D3.5 as a Company-owned DCFC charging service. The rate structure for Rate Schedule D3.5 has a non-capacity energy charge based on time of use and a session fee which includes power supply capacity and is

based on the demand rating of the charging station consistent with the approved rate design in Case No. U-21534.[2878]

Electrify America witness Shah recommended the session fee and volumetric components of Rate Schedule D3.5 be updated to reflect market rates for public fast charging infrastructure at similar power levels in DTE's service territory. In testimony and briefs, Electrify America notes that the Company's Rate Schedule D3.5 sets customer pricing for potential Company-owned DC fast charging stations through a combination of volumetric energy charges and a single fixed charge covering capacity, delivery, and surcharges. It also notes that the on-peak energy rate is $0.08036 per kWh and the off-peak rate is $0.07153 per kWh, with fixed session fees of $21 per session for chargers under 200 kW and $66 per session for chargers above 200 kW.[2879] Pointing out that DTE's proposed energy charges in Rate Schedule D3.5 are "significantly lower than those charged by private companies that own and operate DCFC infrastructure within DTE's service territory," Electrify America initially asked the Commission to increase these charges to reflect prevailing market prices for DCFC services offered by private providers in the Company's territory.[2880] However, Electrify America's acknowledges that concerns about competitive impacts may be premature given DTE's stated plans and the tariff's 100-charger participation cap, but requested that if the Company's plans change or it seeks approval to develop DCFC stations after 2028, the Commission revisit and align customer-facing charges with market pricing charged by private entities.[2881]

[2878] 4 Tr 2586; 2588.
[2879] 4 Tr 3597; Electrify America brief, 2-4
[2880] 4 Tr 3598
[2881] Electrify America brief, 2-4.

In rebuttal, Mr. Turner characterized Rate D3.5 as a pilot rate designed to transparently explore utility-owned charging, emphasizing that any future changes would undergo Commission review and stakeholder input.[2882] The Company also reiterated in briefs that the Company has no plans to operate utility-owned DCFC infrastructure through 2028.[2883] The Company reiterated its disagreement with Electrify America's claim that Rate Schedule D3.5 is fundamentally different from the existing D3 rate and, therefore, not comparable on the basis of volumetric charges alone. DTE argues that Rate Schedule D3.5 uses a time-of-use volumetric component for non-capacity power costs and a fixed session fee to recover capacity, distribution, and part of station capital costs, whereas D3 recovers these elements solely through volumetric charges.[2884] Thus, DTE maintains that focusing only on D3.5's volumetric rates disregards the session fee and yields an inapt comparison. The Company also emphasized that D3.5 is a limited, transparent pilot—capped at 100 chargers, not currently in use, with no deployment planned through 2028—designed to explore utility-owned charging rather than compete with private investment, making claims of competitive distortion speculative.[2885] Thus, DTE maintains that D3.5's design is grounded in cost-of-service principles, provides fairness and regulatory compliance, and any future changes would require Commission review and stakeholder input and asks the Commission to reject Electrify America's proposal.

Electrify America did not file a reply brief.

[2882] 4 Tr 2606-2608.
[2883] DTE brief, 237; DTE reply, 212.
[2884] DTE brief, 235-237; DTE reply, 212.
[2885] DTE brief, 236-237; DTE reply, 237.

This PFD agrees with the Company. As noted by both parties, D3.5 is a limited pilot, is not currently in use, and DTE does not expect deployment before 2028. Since this pilot is designed to explore utility-owned investment (rather than private investment), this PFD agrees that Electrify America's concerns over rate competitiveness is speculative at this time and can be better assessed once the pilot is closer to deployment. This PFD therefore recommends that the Commission approve DTE's Rate Schedule D3.5.

5. Revisions to Rate Schedule D14 on-Peak Period

Mr. Turner also addressed C&I primary Rate Schedule D14, an optional TOU rate with power supply rates that vary depending on season and time of day.[2886] This rate schedule was approved by the Commission in Case No. U-21534 and is expected to be available to customers no later than December 31, 2025.[2887]

No parties opposed Rate Schedule D14 and, thus, this PFD recommends approval.

C. Commercial and Industrial Rate Schedules

DTE's initial brief provided an overview of the Company's proposed Commercial and Industrial Rate Schedule revisions. No parties objected to these revisions[2888] and, thus, this PFD recommends approval of the Company's Commercial and Industrial Rate Schedules.

D. Streetlighting Rate Design

[2886] 4 Tr 2591.
[2887] 4 Tr 2590.
[2888] DTE brief, 239-240; DTE reply, 213.

Mr. Hartley presented testimony in support of DTE's proposed rate design for outdoor lighting and ATS tariff offerings using the lighting model.[2889] He also sponsored Exhibit A-16, Schedule F3, which demonstrates present and proposed rate design, and corresponding revenues by rate schedule, based on billing determinants for the 12 months ending December 31, 2026.[2890]

Mr. Isakson recommended the Company be required to file a proposal in its next rate case for universal lighting rates.[2891] Citing Consumers' move to universal unmetered lighting rates based on each light's wattage, DTE's discontinuation of non-LED lighting to new customers, its discontinuation of servicing non-LED luminaries, and the complexity of DTE's current rate design model compared to other customer rates, Mr. Isakson reasoned that "it is appropriate for the Company to begin the transition to a universal lighting rate design."[2892] DTE indicates its support; thus, this PFD finds that Staff's recommendation should be adopted. [2893]

E. Nuclear Surcharge

DTE's briefs highlight an overview of the Company's proposed Nuclear Surcharge.[2894] No parties opposed this nuclear surcharge and, thus, this PFD recommends the Commission adopt this proposal.

F. Tariffs

1. Residential EV Tariff Minimum Service

[2889] 3 Tr 1409.
[2890] 3 Tr 1432.
[2891] 5 Tr 4906.
[2892] 5 Tr 4906.
[2893] DTE brief, 241; DTE reply, 214.
[2894] DTE brief, 242; DTE reply, 214.

Mr. Isakson recommended that the Company either revise or remove the sentence "Residential minimum service is 10 kW of connected load" from its EV minimum service tariff proposal due to a concern over wording that could create confusion. The Company does not object to Staff witness Isakson's recommendation to remove the referenced sentence from the EV minimum service tariff proposal and, thus, this PFD recommends Staff's proposed revision.

2. Rate D13 – XL Large Industrial Rate

Mr. Turner presented DTE's tariff language modifications for the Company's rate schedules, including development of power supply rates for Rate Schedule D13, the Company's primary customer XL Large Industrial rate class.[2895] Rate Schedule D13 is a primary rate with energy-based delivery charges. According to Mr. Turner, Rate Schedule D13 was designed in a manner consistent with the approved design in Case No. U-21534, the Company's most recent rate case, and utilizes Blue Water Energy Center (BWEC) as a proxy indication of marginal cost to serve.[2896]

Mr. Isakson expressed concern over the facilities allowance currently offered to customers on Rate D13, the Company's economic development rate.[2897] He explained in his direct testimony that while CIAC allowances available to all eligible customers are detailed in the Company's tariffs, along with analogous line extension waivers and allowance for residential and small commercial customers, details of the facilities allowance are not currently reflected in the Company's rate book.[2898] Mr. Isakson, thus,

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[2895] 4 Tr 2590.
[2896] 4 Tr 2596.
[2897] 5 Tr 4914-4915.
[2898] 5 Tr 4914-4915.

recommended that DTE, in its next rate case: (1) propose an exhibit defining the calculation of the facilities allowance for Rate D13 for inclusion in its proposed tariffs; and (2) add language for the facilities allowance for Rate D13 to Section C6 of the Company's rate book.[2899] He reasoned that this will provide transparency for customers and will aid in resolving any possible disputes between the Company and Rate D13 customers should they arise.

The Company did not object to this recommendation and, therefore, this PFD recommends its approval.

3. Reformat of Tariff Pages

Staff recommended DTE Electric be required to reformat tariff pages to list discrete miscellaneous charges as clearly delineated items rather than embedding them in narrative text. The Company did not oppose Staff's recommendation and, therefore, this PFD finds it should be adopted.

XII.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions, and recommendations set forth above, including the findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses leading to an estimated revenue deficiency of approximately $210,876 million with an authorized return on equity of 99% and an overall cost of capital of 5.64%, as well as recommendations regarding various accounting

[2899] 5 Tr 4915.

requests, cost of service allocations, and rate design, and including recommendations for additional Commission investigation, and additional utility reporting and analysis.

Lastly, any errors or omissions in this PFD are the sole responsibility of the undersigned.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sally L. Wallace

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Sally L. Wallace
Administrative Law Judge

Issued and Served:
December 22, 2025

Michigan Public Service Commission
DTE Electric Company
Projected Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending December 31 , 2026
($000)

Case No.: U-21860
PFD
Appendix A

Line No.	(a) Description	(b) Source	(c) Applicant Reply Brief Projection	(d) PFD Adjustment	(e) PFD Projection
1	Rate Base	Exh. A-12, Sch. B1	$ 23,515,626	$ (480,607)	$ 23,035,019
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	$ 1,118,401	$ 131,011	$ 1,249,412
3	Overall Rate of Return	Line 2 ÷ Line 1	4.76%	0.67%	5.42%
4	Required Rate of Return	Exh. A-14, Sch. D1	6.04%	-0.40%	5.64%
5	Income Requirements	Line 1 x Line 4	$ 1,420,979	$ (121,241)	$ 1,299,738
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	$ 302,578	$ (252,253)	$ 50,326
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	$ 408,370	$ (340,449)	$ 67,921
9	Return On - Tree Trim Regulatory Asset	Exh. A-11, Sch. A1.1	11,944	(7,090)	4,854
10	Return On - Monroe Regulatory Asset	Exh. A-11, Sch. A1.2	141,416	(3,315)	138,101
11	Revenue Deficiency / (Sufficiency)-Total	Sum Lines 8, 9, 10	$ 561,730	$ (350,854)	$ 210,876

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Return On
Projected 12 Month Period Ending December 31 , 2026
($000)

Case No.: U-21860
PFD
Appendix A1.1

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	**Return on Tree Trim Regulatory Asset**		
2	Average Balance Regulatory Asset	170,100	Line 16
3	Deferred Tax Liability	(44,056)	- Line 2 x 25.9% Composite Tax Rate
4	Average Net Rate Base	126,044	
5	Authorized Rate of Return on Short Term Debt (pretax)	3.85%	Exhibit A-14, Schedule D1
6	Return on Tree Trim	4,854	

Line No.		2019-A	2020-A	2021-A	2022-A	2023-A	2024-A	2025	2026	
7	**Tree Trim Regulatory Asset**									
8	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	54,438	128,962	-	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges through April 30, 2020 1/		1,200							
10	Regulatory Liability Balance Transfer 4/	-	-	-	-	-	(601)	-	-	
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	53,838	128,962	-	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	314,300	211,238	340,200	340,200	Cumulative Line 11
13	Securitization Amount 2/ 3/					(156,900)			(340,200)	
14	Cumulative Balance at December 31					157,400	211,238	340,200	-	
15	Cumulative Balance at December 31							340,200	-	Assumes 100% of annual spend
16	Average Balance								170,100	

1/ Interest at U-20162 authorized STD rate of 3.56% until U-20561 order was in effect.

2/ Securitization approved per U-21015 order dated June 23, 2021 (up to $156.9 per order page 91)

3/ The Company plans to securitize $340M in 2026

4/ Remaining balance of regulatory liability transferred to regulatory asset per U-21128

Michigan Public Service Commission Case No.: U-21860
DTE Electric Company PFD
Monroe Regulatory Asset - Return On **Appendix A1.2**
Projected 12 Month Period Ending December 31 , 2026
($000)

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	**Return on Monroe Regulatory Asset**		
2	Monroe Regulatory Asset - Average Balance	2,116,934	Exhibit A-12, Schedule B4.4, Line 8
3	Pre-tax Weighted Average Cost of Capital 1/	6.52%	Exhibit S-4, Schedule D1
4	Return on Monroe Regulatory Asset	138,101	

1/ Pretax WACC as proposed in this case was recalculated using 9% ROE in accordance with U-21193 order dated July 26, 2023

Michigan Public Service Commission
DTE Electric Company
Projected Rate Base
Periods Ending December 31, 2023 and December 31 , 2026
($000)

Case No.: U-21860
PFD
Appendix B

Line No.	(a) Description	(b) Source	(c) Applicant Reply Brief Projection	(d) PFD Adjustment	(e) PFD Projection
			(13 Month Average)	(13 Month Average)	(13 Month Average)
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	26,150,061	(507,186)	25,642,875
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	224	-	224
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	2,637,403	-	2,637,403
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	77,542	-	77,542
6	Total Utility Plant	Sum Lines 2 thru 5	28,865,230	(507,186)	28,358,043
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	6,921,497	(26,579)	6,894,918
8	Net Utility Plant	Line 6 + Line 7	21,943,733	(480,607)	21,463,126
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	5,735	-	5,735
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	207,030	-	207,030
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	-	-	-
12	Total Utility Property and Plant	Sum Lines 8 thru 11	22,156,498	(480,607)	21,675,891
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L85 + L100	5,815	-	5,815
14	Net Plant	Line 12 - Line 13	22,150,683	(480,607)	21,670,076
15	Allowance for Working Capital	Exh.A-12, Sch. B4	1,364,943	-	1,364,943
16	Total Rate Base	Line 14 + Line 15	23,515,626	(480,607)	23,035,019

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21860
PFD
Appendix C

DTE Electric Energy Company
Development of Projected Net Operating Income
for the Test Year Ended December 31, 2026
($000)

		Revenue				Expenses									NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line No.	Description (Witness)	Sales Revenue	Base Fuel & Purchase Power Rev.	Other Revenue and R2 Rider	Total	Fuel and Purchased Power	Other O&M Expense	Depreciation & Amort.	Property Taxes	Other Taxes	State & Local Income	FIT	Other Utility (Income) / Deductions	Total	NOI	AFUDC	Loss on Reacquired Securities	Adjusted NOI
	Company Filed																	
	Operating Income (Direct)	4,246,558	1,353,470	118,330	5,718,358	1,353,470	1,392,755	1,359,917	348,018	52,064	61,537	109,372	(6,425)	4,670,708	1,047,651	62,659	(2,435)	1,107,875
	Belle River 1 Chemical Clean				-		(2,400)				149	473		(1,778)	1,778			1,778
	Trenton Channel 2026 O&M				-		(914)				57	180		(678)	678			678
	NICE Software Maintenance				-		(1,000)				62	197		(741)	741			741
	WCB Façade				-		2,254				(140)	(444)		1,670	(1,670)			(1,670)
	Federal Funds Compliance				-		(1,000)				62	197		(741)	741			741
	Merchant Fees Residential				-		(7,013)				436	1,381		(5,196)	5,196			5,196
	Cap Ex Concession Impact on Depreciation & Property Tax				-			(1,585)	(1,428)		187	594		(2,233)	2,233			2,233
	Interest Sync				-						(199)	(651)		(850)	850			850
		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Operating Income (Initial Brief)	4,246,558	1,353,470	118,330	5,718,358	1,353,470	1,382,682	1,358,332	346,589	52,064	62,151	111,299	(6,425)	4,660,161	1,058,197	62,659	(2,435)	1,118,421
	DR Residential Generator Pilot O&M				-		(532)				33	105		(394)	394			394
	Cap Ex Concession Impact on Depreciation & Property Tax				-			280	207		(30)	(96)		361	(361)			(361)
	Interest Sync				-						-	-		-	-			-
		-	-	-	-	-	-	-	-	-	13	40	-	53	(53)	-	-	(53)
1	**Operating Income (Reply Brief)**	4,246,558	1,353,470	118,330	5,718,358	1,353,470	1,382,150	1,358,612	346,796	52,064	62,166	111,347	(6,425)	4,660,181	1,058,177	62,659	(2,435)	1,118,401
	PFD Adjustments																	
2	Sales Adjustment (Isakson)	5,722			5,722						355	1,127		1,482	4,240			4,240
3	PSCR Offset (Isakson)		(983)		(983)						(61)	(194)		(255)	(728)			(728)
4					-						-	-		-	-			-
5	Other Revenue				-						-	-		-	-			-
6	Other Operating Revenue (Isakson)				-						-	-		-	-			-
7	Payment Stability Plan (Braunschweig)			(947)	(947)						(59)	(186)		(245)	(702)			(702)
8					-						-	-		-	-			-
9	Steam Power Generation				-						-	-		-	-			-
10	BRPP U2 Turbine Support Restoration (Kindschy)				-		(2,334)				145	460		(1,729)	1,729			1,729
11	Belle River Startup Study and Tuning (Kindschy)				-		(250)				16	49		(185)	185			185
12	Belle River Unit 1 Boiler Chemical Cleaning (Kindschy)				-		(600)				37	118		(445)	445			445
13	Belle River Chemical Resin Replacements (Kindschy)				-		(800)				50	158		(593)	593			593
14	Monroe Reliability Maintenance (Kindschy)				-		(3,843)				239	757		(2,847)	2,847			2,847
15	Belle River Fuel Handling Post Natural Gas Conversion (Kindschy)				-		(3,520)				219	693		(2,608)	2,608			2,608
16	Steam Generation Periodic Outage Normalization (Kindschy)				-		(4,372)				272	861		(3,239)	3,239			3,239
17	Total Steam Power Generation - Inflation (Kindschy)				-		(2,635)				164	519		(1,952)	1,952			1,952
18					-						-	-		-	-			-
19	Fuel Supply & MERC Fuel Handling				-						-	-		-	-			-
20	Total Fuel Supply & MERC Fuel Handling - Inflation (Kindschy)				-		(119)				7	23		(88)	88			88
21					-						-	-		-	-			-
22	Nuclear Power Generation				-						-	-		-	-			-
23	Total Nuclear Power Generation - Inflation (Kindschy)				-		(1,749)				109	344		(1,296)	1,296			1,296
24					-						-	-		-	-			-
25	Hydraulic Power Generation				-						-	-		-	-			-
26	Total Hydraulic Power Generation - Inflation (Kindschy)				-		(169)				10	33		(125)	125			125
27					-						-	-		-	-			-
28	Other Power Generation				-						-	-		-	-			-
29	Trenton BESS Operation (Kindschy)				-						-	-		-	-			-
30	Peaker Increased Maintenance (Kindschy)				-		(4,303)				267	847		(3,188)	3,188			3,188
31	Total Other Power Generation - Inflation (Kindschy)				-		(382)				24	75		(283)	283			283
32	BWEC Normalization (AG)				-		(3,562)				221	702		(2,639)	2,639			2,639
33					-						-	-		-	-			-
34	Distribution				-						-	-		-	-			-
35	Total Distribution - Inflation (Rueckert)				-		(4,165)				259	820		(3,086)	3,086			3,086
36	Tree Trimming (AG)				-		(8,322)				517	1,639		(6,166)	6,166			6,166
37	Staking & Locating (AG)				-		(675)				42	133		(500)	500			500
38	Distribution - Constand Dollar				-		(12,044)				748	2,372		(8,924)	8,924			8,924
39	Distribution - Consultant				-		(2,128)				132	419		(1,577)	1,577			1,577
40					-						-	-		-	-			-
41	Customer Service O&M - Inflation (PFD)				-		(1,347)				84	265		(998)	998			998
42	IT O&M - Inflation (PFD)				-		(1,101)				68	217		(816)	816			816

43					-						-	-		-	-				-
44	Uncollectible Accounts Expense				-						-	-		-	-				-
45	Payment Stability Plan (Braunschweig)				-		(947)				59	186		(702)	702				702
46	Uncollectible Accounts Expense (Rueckert)				-		(614)				38	121		(455)	455				455
47					-						-	-		-	-				-
48	Regulated Marketing				-						-	-		-	-				-
49	DR Call Center (Towslee)				-						-	-		-	-				-
50	Regulated Marketing Inflation (McMillan-Sepkoski)				-		(314)				19	62		(233)	233				233
51	Regulated Marketing - Base O&M (AG)				-		(2,739)				170	539		(2,029)	2,029				2,029
52					-						-	-		-	-				-
53	Corporate Support				-						-	-		-	-				-
54	Incentive Compensation - Financial Measures (McMillan-Sepkoski)				-		(35,838)				2,226	7,059		(26,554)	26,554				26,554
55	Restricted Stock (McMillan-Sepkoski)				-		(7,730)				480	1,522		(5,727)	5,727				5,727
56	Communication Compliance and Data Loss Prevention (DLP) Diversification (Zich				-		(283)				18	56		(210)	210				210
57	Customer Insight Platform Application Health (Klocke)				-		(100)				6	20		(74)	74				74
58	Customer Relationship and Billing Program (Klocke)				-		(2,695)				167	531		(1,997)	1,997				1,997
59	DTE Mobile App Application Health (Klocke)				-		(170)				11	34		(126)	126				126
60	Outage WISMO and Map Sustainment (Klocke)				-		(249)				15	49		(185)	185				185
61	Outage WISMO, PPS, and Map Enhancement Klocke)				-		(525)				33	103		(389)	389				389
62	Projects with level 2 cost estimates (Rogers)				-		(16)				1	3		(12)	12				12
63	Projects with level 3 cost estimates (Rogers)				-		(2,086)				130	411		(1,545)	1,545				1,545
64	Corporate Support and Inflation (Rueckert)				-		(23,545)				1,462	4,637		(17,445)	17,445				17,445
65	EEI Membership Dues (Soulardarity)				-		(1,476)				92	291		(1,094)	1,094				1,094
66	Employee Pension and Benefits (Rueckert)				-						-	-		-	-				-
67	New Hire VEBA (AG)				-		(1,808)				112	356		(1,340)	1,340				1,340
68	Active Employee Health Care Expense (AG)				-		(513)				32	101		(380)	380				380
69	Employee Savings Plan (AG / DTE recalc)				-		(173)				11	34		(128)	128				128
70					-						-	-		-	-				-
71	Impact of Cap Ex Adj on Prop. Tax & Depr. (Hecht)				-			(32,793)	(1,561)		2,133	6,766		(25,454)	25,454				25,454
72					-						-	-		-	-				-
73	Remove Prop. Tax Exp. Calculated on Intangible Plant Cap Ex				-				(1,743)		108	343		(1,291)	1,291				1,291
74	Proforma Interest (Nichols)				-						588	1,865		2,452	(2,452)				(2,452)
75	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	0	2	-	2	(2)	-	-		(2)
76	**Total Adjustments**	5,722	(983)	(947)	3,793	-	(140,240)	(32,793)	(3,304)	-	11,774	37,344	-	(127,218)	131,011	-	-		131,011
77	**PFD NOI - Test Year**	4,252,281	1,352,488	117,383	5,722,151	1,353,470	1,241,909	1,325,819	343,492	52,064	73,941	148,692	(6,425)	4,532,963	1,189,188	62,659	(2,435)		1,249,412

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For the 13-Month Average Period Ending Dec. 31, 2026

Case No.: U-21860
PFD
Appendix D

Line No.	(a) Description	(b) Capital Structure Amount ($000)	(c) Capital Structure Percent Permanent Capital	(d) Capital Structure Percent of Total Capital	(e) Cost Rate %	(f) Weighted Costs Permanent Capital	(g) Weighted Costs Total Cost %	(h) Weighted Costs Conversion Factor	(i) Weighted Costs Pre-Tax Return
1	Long-Term Debt	9,213,994	50.00%	39.11%	4.27%	2.13%	1.67%	1.0000	1.67%
2	Preferred Stock	0	0.0%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	9,213,994	50.00%	39.11%	9.90%	4.95%	3.87%	1.3496	5.23%
4	Total	18,427,988	100.0%			7.08%			
5	Short-Term Debt	562,850		2.39%	3.85%		0.09%	1.0000	0.09%
6	Investment Tax Credit (ITC) - Debt	17,096		0.07%	4.27%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	17,096		0.07%	9.90%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	34,192							
9	Deferred Income Taxes (Net)	4,535,041		19.25%	0.000%		0.00%		0.00%
10	Total	23,560,071		100.00%			5.64%		7.00%

Line	Party	(a) Adjustment Description	(b) Total Cap Ex Adj.	(c) Test Year Impacts From Adjustment(s) Plant	(d) Accum Depr.	(e) Rate Base	(f) Depreciation	(g) Property Tax
1		**Production Plant - Steam:**						
2	AG	Routine - 5 Projects in Preliminary /Premature Stage	(63,703,000)	(31,851,500)	(515,543)	(31,335,957)	(1,031,087)	-
3	AG	Non Routine - Trenton Channel Seawall & Green Path	(9,456,000)	(4,728,000)	(76,527)	(4,651,473)	(153,053)	-
4		**TOTAL: PRODUCTION PLANT**	**(73,159,000)**	**(36,579,500)**	**(592,070)**	**(35,987,430)**	**(1,184,140)**	**-**
5		**Nuclear**						
6	AG	Routine - Document Mgmt System Enchancements	(9,567,000)	----------In CWIP with AFUDC offset----------			-	(1,834)
7	AG	Routine - Reactor Recirculation System (RRS) Replacements	(5,125,000)	----------In CWIP with AFUDC offset----------			-	-
8	AG	Non Routine - Underground Safety - Related Service Water Piping	(12,600,000)	(12,600,000)	(1,073,759)	(11,526,241)	(536,879)	(290,455)
9	AG	Non-Routine - Turbine Controls Replacements	(6,012,000)	----------In CWIP with AFUDC offset----------			-	(7,444)
10	AG	Non-Routine - Reactor Recirculation Motor-Generator (RRMG) Replacements	(24,755,000)	----------In CWIP with AFUDC offset----------			-	(31,358)
11	AG	Non-Routine - Circulating Water (CW) Traveling Screens	(6,273,000)	----------In CWIP with AFUDC offset----------			-	(494)
12		**TOTAL: NUCLEAR**	**(64,332,000)**	**(12,600,000)**	**(1,073,759)**	**(11,526,241)**	**(536,879)**	**(331,586)**
13	ABATE/AG/M	**Distribution Base Capital Programs:**						
14	NSC/Staff	Constant Dollar Averaging (CDA) Methodology	(130,964,000)	(97,722,500)	(3,321,237)	(94,401,263)	(4,001,881)	(682,003)
15	MNSC	Inflation Rates (2.9%-2024, 2.7%-2025, 2.4%-2026)	(17,290,000)	(11,633,000)	(360,557)	(11,272,443)	(476,389)	(63,207)
16	AG	Emergent Replacements - Non Storm - 2026 Corrective Maintenance	(13,564,000)	(6,782,000)	(138,866)	(6,643,134)	(277,733)	-
17	AG	Emergent Replacements - Substation Reactive - 2025 Substation Facility Repair	(8,000,000)	(8,000,000)	(327,612)	(7,672,388)	(327,612)	(71,922)
18	AG	Emergent Replacements - Substation Reactive - 2026 Corrective Maintenance	(9,850,000)	(4,925,000)	(100,843)	(4,824,157)	(201,686)	-
19	AG	Relocations - I-375 Relocations	(9,600,000)	(8,100,000)	(300,993)	(7,799,007)	(331,707)	(59,336)
20	Staff	Electric System Equipment - Projected Meters	(10,819,213)	(8,082,244)	(274,938)	(7,807,306)	(330,980)	(56,536)
21		**Distribution Strategic Capital Programs:**						
22		**Infrastructure Resilience and Hardening**						
23	Staff	$200M PTMM to 2026 IRM (less Ann Arbor Pole Material Reduction)	(197,378,299)	(98,689,150)	(2,020,733)	(96,668,416)	(4,041,467)	-
24	Ann Arbor	PTMM - Pole Material Cost Increase	(2,621,701)	(1,310,851)	(26,841)	(1,284,010)	(53,681)	-
25	PFD	$10M Small Wire Replacement Program to 2026 IRM	(10,000,000)	(5,000,000)	(102,379)	(4,897,621)	(204,757)	-
26		**Infrastructure Redesign and Modernization**						
27	Staff	Subtrans Redesign & Rebuild: Transformer High Side Protection Program	(7,574,530)	(6,068,779)	(217,694)	(5,851,085)	(248,525)	(48,262)
28	Staff	Subtrans Redesign & Rebuild: Reverse Power Relay Scheme Program	(400,000)	(300,000)	(10,238)	(289,762)	(12,285)	(2,115)
29	Staff	CODI: Alfred Substation Expansion	(2,607,818)	(2,428,309)	(95,767)	(2,332,542)	(99,443)	(23,785)
30	Staff	Subtransmission Redesign & Rebuild: Trunk 3509	(1,501,600)	(750,800)	(15,373)	(735,427)	(30,746)	(7,941)
31	Staff	CODI: Targeted Network Secondary Cable Replacement	(1,335,262)	(667,631)	(13,670)	(653,961)	(27,340)	(6,520)
32	Staff	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - North	(300,000)	(150,000)	(3,071)	(146,929)	(6,143)	-
33	Staff	4.8 kV CC: Melvindale	(360,000)	(180,000)	(3,686)	(176,314)	(7,371)	-
34	Staff	Subtransmission Redesign & Rebuild: Trunk 7105	(200,000)	----------In CWIP with AFUDC offset----------			-	-
35	Staff	System Loading: Grenada	(16,499,507)	----------In CWIP with AFUDC offset----------			-	(54,292)
36	Staff	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	(683,769)	----------In CWIP with AFUDC offset----------			-	-

Line		(a) Adjustment Description	(b) Total Cap Ex Adj.	(c) Test Year Impacts From Adjustment(s) Plant	(d) Accum Depr.	(e) Rate Base	(f) Depreciation	(g) Property Tax
37	AG-MN	Circuit Conversions - Pontiac Overhead	(15,791,000)	(7,895,500)	(161,666)	(7,733,834)	(323,332)	-
38	AG-MN	Circuit Conversions - Pontiac Underground	(4,901,000)	----------In CWIP with AFUDC offset----------			-	-
39	AG-MN	Circuit Conversions - Hilton	(9,407,000)	----------In CWIP with AFUDC offset----------			-	-
40	AG-MN	Circuit Conversions - BRITN	(900,000)	----------In CWIP with AFUDC offset----------			-	-
41	AG-MN	Circuit Conversions - Pittsfield	(1,236,000)	----------In CWIP with AFUDC offset----------			-	(683)
42	ABATE	Pilot Strategic and Service Undergrounding - Spruce Pilot	(11,592,000)	(5,796,000)	(118,677)	(5,677,323)	(237,355)	-
43		**Technology and Automation**						
44	Staff	CVR/VVO	(7,122,860)	(3,561,430)	(118,714)	(3,442,716)	(237,429)	-
45	Staff	Distribution Automation	(133,353,462)	(97,803,517)	(5,335,236)	(92,468,280)	(6,520,234)	-
46	Staff	Distribution Sensing and Monitoring	(3,445,866)	(3,023,055)	(115,141)	(2,907,913)	(123,799)	(27,502)
47	Staff	Customer Power Status Visibility	(7,880,000)	(4,880,000)	(138,416)	(4,741,584)	(199,843)	(19,884)
48	Staff	Distribution SCADA Historian	(2,500,000)	(1,250,000)	(25,595)	(1,224,405)	(51,189)	-
49	Staff	Mobile Equipment Replacement	(1,750,000)	(875,000)	(17,916)	(857,084)	(35,833)	-
50	CEO	DERMS	(4,300,000)	----------In CWIP with AFUDC offset----------			-	(7,933)
51		**TOTAL: DISTRIBUTION**	**(645,728,887)**	**(385,874,764)**	**(13,365,862)**	**(372,508,902)**	**(18,408,762)**	**(1,131,922)**
52		**Demand Side Management:**						
53	Staff	Other Demand Response Programs and Pilots - C&I Battery Pilot	(508,094)	(508,094)	(159,228)	(348,866)	(101,619)	(10,139)
54		**TOTAL: DEMAND SIDE MANAGEMENT**	**(508,094)**	**(508,094)**	**(159,228)**	**(348,866)**	**(101,619)**	**(10,139)**
55		**Information Technology:**						
56	Staff	Level 2 Cost Estimate Reductions	(685,400)	(342,700)	(34,270)	(308,430)	(68,540)	-
57	Staff	Level 3 Cost Estimate Reductions	(24,443,600)	(18,760,300)	(3,183,730)	(15,576,570)	(3,752,060)	-
58	Staff	Overhead Reductions	(15,503,984)	(9,733,052)	(1,718,765)	(8,014,286)	(1,946,610)	-
59		**Customer IT**						
60	Staff	Customer Insight Platform Application Health	(4,275,264)	(2,137,632)	(213,763)	(1,923,869)	(427,526)	-
61	Staff	DTE Mobile App Application Health	(1,100,925)	(550,463)	(55,046)	(495,416)	(110,093)	-
62	Staff	Payment Merchant Fees	(9,998,417)	(9,998,417)	(1,999,683)	(7,998,734)	(1,999,683)	-
63	Staff	Outage WISMO and Map Sustainment	(8,250,000)	(5,625,000)	(862,500)	(4,762,500)	(1,125,000)	-
64	Staff	Outage WISMO, PPS, and Map Enhancements	(1,700,001)	(850,001)	(85,000)	(765,000)	(170,000)	-
65	Staff	Customer Relationship and Billing Program	(6,310,678)	(3,155,339)	(315,534)	(2,839,805)	(631,068)	-
66		**Plant & Field**						
67	Staff	Corporate Instance - Maximo Application Suite Upgrade Phase 2	(1,400,000)	(700,000)	(70,000)	(630,000)	(140,000)	-
68	Staff	Maximo Engineering Process Automation	(2,552,000)	(2,552,000)	(1,020,800)	(1,531,200)	(510,400)	-
69		**Information Protection Security**						
70	Staff	Communication Compliance and Data Loss Prevention (DLP) Diversification	(370,000)	(278,000)	(46,400)	(231,600)	(55,600)	-

Line		(a) Adjustment Description	(b) Total Cap Ex Adj.	(c) Test Year Impacts From Adjustment(s) Plant	(d) Accum Depr.	(e) Rate Base	(f) Depreciation	(g) Property Tax
71		**Infrastructure Operations**						
72	Staff	Backup Environmental Growth	(200,000)	(150,000)	(25,000)	(125,000)	(30,000)	-
73	Staff	Network Hardening and Operations Project	(500,000)	(250,000)	(25,000)	(225,000)	(50,000)	-
74	Staff	Digital Worker Experience EOL Electric	(1,811,576)	(1,704,023)	(649,343)	(1,054,680)	(340,805)	-
75	Staff	Field Worker Device EOL	(135,000)	(67,500)	(6,750)	(60,750)	(13,500)	-
76		**Enterprise Data Analytics**						
77	Staff	DO Productivity Center	(439,000)	(439,000)	(175,600)	(263,400)	(87,800)	-
78		**TOTAL: INFORMATION TECHNOLOGY**	**(79,675,845)**	**(57,293,426)**	**(10,487,185)**	**(46,806,240)**	**(11,458,685)**	**-**
79		**Corporate Staff:**						
80	Staff	Electric Vehicle Fleet and Maintenance	(1,362,000)	(681,000)	(26,203)	(654,797)	(52,406)	-
81	AG	Facilities Contruction and Upgrades - Plaza Renovation	(7,755,000)	(5,878,000)	(380,114)	(5,497,886)	(452,336)	(38,086)
82	AG	Facilities Contruction and Upgrades - End of Life Repairs and Replacements - Other	(8,955,000)	(6,671,500)	(425,536)	(6,245,964)	(513,399)	(41,770)
83	Staff	Other Miscellaneous - Environmental Capital Projects - Emergent	(1,300,000)	(950,000)	(59,639)	(890,361)	(73,106)	(6,346)
84	Staff	Other Miscellaneous - Human Resources - Placeholder	(200,000)	(150,000)	(9,619)	(140,381)	(11,543)	(1,058)
85		**TOTAL: CORPORATE STAFF**	**(19,572,000)**	**(14,330,500)**	**(901,112)**	**(13,429,388)**	**(1,102,789)**	**(87,260)**
86		**TOTAL CAPITAL EXPENDITURE ADJUSTMENTS**	**(882,975,826)**	**(507,186,284)**	**(26,579,216)**	**(480,607,067)**	**(32,792,874)**	**(1,560,907)**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN)
) SS.
County of Ingham)
_____)

Case No. U-21860

PROOF OF SERVICE

Shelly Reynolds being duly sworn, deposes and says that on December 22, 2025, she served a copy of the attached Notice of Proposal for Decision and Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

_____
Shelly Reynolds

Subscribed and sworn to before me this
22nd day of December 2025.

_____
Christine Gibson
Notary Public, Clinton County, Michigan
My Commission Expires September 16, 2026

Case No. U-21860
Service List

DTE ELECTRIC COMPANY
Jon P. Christinidis
Andrea E. Hayden
Carlton D. Watson
John A. Janiszewski
Breanne K. Reitzel
Charlotte A. Mitchelle
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Michael J. Pattwell
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Jessica York, consultant
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Nathan Inks
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