S T A T E   O F   M I C H I G A N

BEFORE 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 distribution and supply of electric energy, and for miscellaneous accounting authority.	)))))))	Case No. U-21534

At the January 23, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Alessandra R. Carreon, Commissioner

ORDER

TABLE OF CONTENTS

I. HISTORY OF PROCEEDINGS

On March 28, 2024, DTE Electric Company (DTE Electric) filed an application requesting authority to increase its retail rates by approximately $456.4 million, effective as early as January 28, 2025.[1] DTE Electric also requested other forms of regulatory relief, including approval to amend its rate schedules and rules governing the distribution and supply of electric energy and the approval of several pilots and various accounting proposals. The utility is currently providing service pursuant to rates established by the December 1, 2023 order in Case No. U-21297 (December 1 order). Application, p. 1.

According to DTE Electric, the rate increase sought in this case is based on the utility's projections from relevant items of investment, expense, and revenue for a test year covering the 12-month period from January 1 through December 31, 2025. DTE Electric explains in its application that the starting point for determining its revenue deficiency is the historical data from year-end 2022, which was then normalized and adjusted for known and measurable changes to arrive at the utility's projected test year. *Id*., pp. 2-3. DTE Electric states that the rate increase is necessary to recover increased investments in plant involving generation; to support the company's carbon reduction plans and the state's clean energy goals; to recover investments in the electric distribution system; to improve power reliability; and to recover associated depreciation and property tax increases. DTE Electric proposes a return on equity (ROE) of 10.50% with an overall rate of return (ROR) of 5.92% after tax, 7.37% pre-tax. *Id*., p. 4. The utility also requests a permanent capital structure of approximately 50% equity and 50% long-term debt and includes a projected average rate base of approximately $24.2 billion for the test year.

[1] In its initial brief, p. 2, DTE Electric revises its request to $446.2 million. In its reply brief, p. 4, the company revises its request to $441.0 million.

DTE Electric explains that its request includes the continuation of the tree-trimming surge program, the conversion of the Belle River Power Plant (Belle River) from coal to natural gas, and the retirement and decommissioning of five power plants. *Id*., p. 2. The application addresses major capital investment projects from 2022 through 2025. Attachment 2 to the application illustrates the company's proposal for allocating the revenue among its rate classes, and Attachment 3 illustrates typical electric bills resulting from approval of the application. DTE Electric also proposes changes to its tariffs, the introduction of new rate schedules, and the expansion of the infrastructure recovery mechanism (IRM) to include the recovery of distribution capital expenditures related to electric vehicles (EVs) and distributed energy resources (DERs) for 2026 and 2027. *Id*., pp. 3-4. DTE Electric proposes continued regulatory asset treatment for tree trim surge costs, and similar treatment for a new storm restoration cost sharing mechanism (SRCSM). The application also includes several proposed pilots.

On April 26, 2024, Administrative Law Judge Sally L. Wallace (ALJ) conducted a prehearing conference at which the ALJ recognized the intervention of the Michigan Department of Attorney General (Attorney General), and granted petitions to intervene filed by Energy Michigan; Michigan Energy Innovation Business Council (MEIBC), Institute for Energy Innovation (IEI), and Advanced Energy United (collectively, MEIU); Foundry Association of Michigan; Michigan Environmental Council (MEC), Natural Resources Defense Council, Inc. (NRDC), Sierra Club, and Citizens Utility Board of Michigan (CUB) (collectively, MNSC); Michigan Cable Telecommunications Association, Inc.; Association of Businesses Advocating Tariff Equity (ABATE); The Kroger Co. (Kroger); Utility Workers Union of America, AFL-CIO Local 223; Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations or CEOs); Michigan

Municipal Association for Utility Issues (MI-MAUI); City of Ann Arbor (Ann Arbor); Walmart Inc. (Walmart); Great Lakes Renewable Energy Association, Inc. (GLREA); Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy Organizations or DAAOs); International Transmission Company d/b/a *ITC*Transmission (ITC); Electrify America, Inc. (Electrify America); and EVgo Services LLC (EVgo). DTE Electric and the Commission Staff (Staff) also participated in the proceeding. A schedule for the case was established by the ALJ in accordance with the 10-month timeframe set forth in MCL 460.6a(5).

On April 29, 2024, the ALJ adopted a protective order for use in the matter.

On May 8, June 21 and 25, and July 19, 2024, DTE Electric filed revised direct testimony. On June 21, 2024, DTE Electric filed additional direct testimony.

On June 26, 2024, the ALJ issued a scheduling memo indicating that the Commission would read the record in this proceeding.

On July 25-26, 2024, direct testimony and exhibits were filed by the Staff; the Attorney General; ABATE; CUB and MEC; CUB, MEC, and NRDC; the Attorney General, MEC, and NRDC (collectively, AGMN);[2] MNSC; MEIU; Ann Arbor; MI-MAUI; the CEOs; GLREA; Energy Michigan; Electrify America; EVgo; Walmart; ITC; and the DAAOs, some of which were filed confidentially.[3] On July 29, 2024, the Staff filed revised direct testimony. On August 8, 2024, MI-MAUI filed confidential direct testimony. On August 13, 2024, Electrify America filed revised direct testimony.

[2] AGMN did not file any briefs. The testimony of AGMN's witnesses (Mr. Alvarez and Mr. Stephens) is addressed in the briefs filed by MNSC. The Attorney General makes reference to some of the testimony, and states that she adopts MNSC's briefing on the issues covered in the testimony of these two witnesses. Attorney General's reply brief, p. 5, n. 17.

[3] Some of the confidential evidence contains critical energy/electric infrastructure information (CEII).

On August 16, 2024, DTE Electric, the Staff, MEIU, ABATE, Kroger, Energy Michigan, ITC, MNSC, EVgo, Electrify America, the CEOs, and the DAAOs filed rebuttal testimony.[4] On August 19, 2024, Energy Michigan filed revised rebuttal testimony. On August 23, 2024, MNSC filed revised direct testimony, some of it confidential. On August 23, 2024, AGMN filed a motion to strike certain rebuttal testimony filed by DTE Electric. On August 26, 2024, ABATE filed revised rebuttal testimony. On August 30, 2024, DTE Electric filed a response to AGMN's motion to strike. On August 30, 2024, MI-MAUI filed revised direct testimony, and on September 3, 2024, MI-MAUI filed the confidential version of that testimony.

Evidentiary hearings were held on September 4-10, 2024, wherein testimony and exhibits were bound into the record and cross-examination took place. On September 4, 2024, the ALJ ruled on AGMN's motion to strike, granting it in part and denying it in part. 2 Tr 52-53, 56-57, and 61.

On September 18, 2024, the Commission held a hearing at Mumford High School in Detroit, Michigan, to receive public comment.[5] On September 20, 2024, the Staff filed a motion regarding GLREA's repeated failure to execute proper service. On September 23, 2024, MEIU indicated that it had inadvertently included confidential material in Volume 6 of the transcript and requested its removal from the docket. On September 24, 2024, the court reporter filed a revised version of Volume 6 of the transcript. On September 27, 2024, GLREA filed a response to the Staff's motion regarding a failure to serve. On October 3, 2024, the ALJ ruled on the motion. *See*, Case No. U-21534, filing #U-21534-0505.

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[4] Kroger's filing was not entered into the record.

[5] A transcript of the public hearing is available here: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000L2VwYAAV (accessed January 20, 2025)

Thereafter, DTE Electric, the Staff, the Attorney General, GLREA, the DAAOs, the CEOs, MNSC, MEIU, Electrify America, MI-MAUI, Energy Michigan, EVgo, ABATE, Walmart, ITC, and Ann Arbor filed initial briefs on October 3, 2024. On October 7, 2024, MNSC filed corrected public and confidential initial briefs.[6] On October 23, 2024, DTE Electric, the Staff, the Attorney General, GLREA, the DAAOs, the CEOs, MNSC, MEIU, MI-MAUI, Energy Michigan, EVgo, ABATE, ITC, and Ann Arbor filed reply briefs. On October 25, 2024, the Staff filed a corrected reply brief.[7]

II. <u>EVIDENTIARY RECORD</u>

The record consists of testimony from 92 witnesses contained within 5,468 pages of public and confidential transcript, along with 886 exhibits (inclusive of schedules). The docket also contains numerous public comments which can be viewed in the section of the docket labeled "Case Comments." *See*, Case No. U-21534, filing ##U-21534-0001-CC through U-21534-0573-CC (as of January 17, 2025).

Despite the voluminous record and the number and complexity of issues presented in this case, legislation requires that the Commission reach a final decision in this matter within a 10-month time frame. MCL 460.6a(5). As a result, it is noted that not all of the material presented in this case will be expressly discussed in this order. The various parties' summaries of the evidence and arguments in support of their respective positions are fully set forth in the evidentiary record. While the Commission has considered the entire record in arriving at its findings and conclusions expressed in this order, only the arguments and evidence necessary for a reasoned analysis of the disputed issues will be specifically addressed in this order.

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[6] All cites in this order are to MNSC's corrected briefs.

[7] All cites in this order are to the Staff's corrected reply brief.

A. Direct Testimony

DTE Electric filed direct testimony from the following witnesses:

Mr. Robert A. Bellini, Manager, Community Lighting,[8] provides the energy forecast for outdoor lighting and the proposed rate design for the outdoor lighting rate schedules, the historic and projected Community Lighting operations and maintenance (O&M) expenses, and the Community Lighting capital expenditures at 6 Tr 3095-3185.[9]

Ms. Pina Bennet, Director, Electric Marketing, discusses expenditures for the Charging Forward programs and pilots, the Transportation Electrification Plan (TEP), and merchant fees at 6 Tr 1917-2021.

Mr. Shawn D. Burgdorf, Manager, Power Supply Strategy and Modeling, Generation Optimization, provides the projected wholesale market energy sales revenue at 6 Tr 2333-2353.

Mr. Jeffery C. Davis, Expert, Nuclear Strategic Business Operations, discusses nuclear O&M expenses and capital expenditures for the test period and the nuclear surcharge at 6 Tr 1802-1916.

Mr. Satvir Deol, Director, Substation Operations, discusses capital investments in infrastructure redesign and modernization and the programs associated with the IRM at 5 Tr 1126-1391 (Mr. Deol's confidential testimony appears in Confidential CEII Record Vol. 5).

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[8] If not otherwise specified, the named witness in DTE Electric's list of witnesses is an employee of DTE Electric.

[9] Direct testimony, rebuttal testimony, and cross-examination for a single witness were (for the most part) entered into the record together, thus the transcript cites in this section of the order provide the complete testimony for that witness unless indicated otherwise. Transcript cites for witnesses who appeared only on rebuttal (and not on direct) are provided below in the section describing rebuttal. Confidential direct testimony appears in Confidential Record Vol. 6, and confidential cross-examination appears in Confidential CEII Record Vols. 4 and 5. All cites to the public version of Vol. 6 are to the revised version filed on September 24, 2024.

Ms. Morgan Elliott Andahazy, Director, Project Management Organization, discusses capital investments in infrastructure resilience and hardening and programs included in the IRM at 4 Tr 899-1113.

Mr. Keegan Farrell, Manager, Demand Response, discusses the development of demand response (DR) efforts and expenditures associated with DR programs and pilots at 6 Tr 2657-2723.

Mr. Neal T. Foley, Director, Regulatory Affairs for DTE Energy Corporate Services, LLC (DTE ECS), a subsidiary of DTE Energy Company (DTE Energy), provides an overview of the case and the methodology used to develop the company's projections, and describes the IRM and the SRCSM at 2 Tr 62-277. He adopts the testimony originally filed by Adella F. Crozier with DTE Electric's application. *See*, 2 Tr 70, 187.

Ms. Margaret E. Guillaumin, Plant Director, Energy Supply Operations Performance, discusses projected capital expenditures and O&M expenses for energy supply from steam power generation, hydraulic generation, and fossil-based generation at 6 Tr 1582-1747.

Ms. Shannen M. Hartwick, Director of Automation, discusses projected capital expenditures for technology and automation and programs included in the IRM at 4 Tr 622-898 (Ms. Hartwick's confidential testimony appears in Confidential CEII Record Vol. 4).

Mr. Michael J. Hatsios, Director, Customer Service Operations for DTE ECS, discusses certain capital investments in the information technology (IT) portfolio and customer service O&M expense at 6 Tr 2184-2332.

Mr. Brian L. Hill, Director, Southwest Regional Customer Operations and Scheduling and Coordination, discusses capital expenditures associated with emergent replacements, customer connections, and relocations, and provides an update on MISS DIG at 6 Tr 3027-3094.

Mr. Allen J. Kryscynski, Acting Director, Distribution Operations Regulatory Strategy and Grid Modernization, discusses O&M expenses for the distribution operations' Global Prioritization Model (GPM), federally funded grants, and the company's approach to environmental justice at 3 Tr 288-610.

Mr. Robert J. Lee, Manager, Environmental Strategy for DTE ECS, discusses effluent limitation guideline compliance status and coal combustion residuals at 6 Tr 2724-2748.

Mr. Timothy J. Lepczyk, Assistant Treasurer and Director, Corporate Finance, Insurance and Development for DTE ECS, discusses DTE Electric's proposed capital structure, and short- and long-term debt at 6 Tr 2543-2568.

Mr. Markus B. Leuker, Manager, Corporate Energy Forecasting for DTE ECS, discusses the forecast for electric sales, maximum demand, and system output, and the outlook for the economy at 6 Tr 1768-1801.

Mr. Habeeb J. Maroun, Regulatory Strategy Consultant, Revenue Requirements Department for DTE ECS, presents the cost of service study (COSS) and the alternate COSS, and discusses revenue requirement calculations at 6 Tr 2749-2800.

Mr. David C. Milo, Fuel Resource Specialist, Fuel Supply, discusses projections for DTE Electric Fuel Supply and Midwest Energy Resources Company (MERC & Fuel Supply) at 6 Tr 1748-1767.

Mr. Pankaj Sharma, Director, Information Officer, Information Technology Services for DTE ECS, discusses IT capital investments and planning at 6 Tr 2022-2183.

Mr. Jason E. Sparks, Director, Revenue Management and Protection for DTE ECS, discusses low-income programs and uncollectibles at 6 Tr 2354-2400.

Ms. Rachel Steudle, Director of Tree Trimming, discusses vegetation management and the O&M expenses related to the tree trimming surge program, and the program's connection to the Distribution Grid Plan (DGP) at 6 Tr 2959-3026.

Ms. Theresa Uzenski, Manager, Regulatory Accounting for DTE ECS, discusses the company's financial statements, the development of test year projections, the capital expenditures and O&M expenses associated with the Corporate Staff Group, and the shared asset charge at 6 Tr 1461-1581.

Mr. Kirk M. Vangilder, Principal Financial Analyst, Revenue Requirements for DTE ECS, discusses the 2022 revenue sufficiency, the test year revenue deficiency, interest synchronization, and the revenue conversion factor, and projects the revenue requirement for certain programs including the IRM at 6 Tr 2801-2823.

Dr. Bente Villadsen, Principal at The Brattle Group, discusses the cost of capital, financial risk, and the recommended ROE at 6 Tr 2401-2542.

Mr. Aaron Willis, Manager, Regulatory Economics for DTE ECS, discusses forecasted allocation schedules, power supply costs, rate design, IRM design, and other tariffs at 6 Tr 2569-2656.

Ms. Sherri Wisniewski, Director, Tax Operations for DTE ECS, discusses federal income tax, state corporate tax, municipal tax, property tax, and other taxes at 6 Tr 2824-2849.

Mr. Matthew A. Fix, Director, Compensation and Retirement Income for DTE ECS, discusses employee compensation practices and benefits expenses at 6 Tr 2850-2916.[10]

Mr. Jerome K. Hooper, Manager, Health and Welfare Benefits and Occupational Health for DTE ECS, discusses benefits and other post-employment benefit (OPEB) expense at 6 Tr 2917-2958.[11]

The Staff filed direct testimony from the following witnesses:

Mr. Tayler Becker, Manager, Distribution Planning Section, Energy Resources Division, discusses capital expenditures on overhead-to-underground conversions at 6 Tr 5029-5043.

Mr. Jonathon J. DeCooman, Public Utilities Engineering Specialist, Resource Optimization and Certification Section, Energy Resources Division, discusses adjustments to capital expenditures for other power generation – non-routine, including blackstart projects, and for certain pilots at 6 Tr 5044-5069.

Mr. Roger A. Doherty, Manager, Resource Adequacy and Forecasting Section, Energy Resources Division, discusses capital costs associated with demand response issues and future analysis at 6 Tr 5070-5078.

Mr. Allan D. Freeman, Assistant to the Division Director, Energy Resources Division, discusses DTE Electric's proposals related to EVs at 6 Tr 5079-5090.

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[10] On June 21, 2024, DTE Electric filed the additional direct testimony of two new witnesses, Mr. Fix and Mr. Hooper. In the cover letter with that filing, the company explains that Mr. Fix and Mr. Hooper are each adopting parts of the direct testimony of Michael S. Cooper originally filed with DTE Electric's application on March 28, 2024. However, Mr. Fix and Mr. Hooper do not provide testimony indicating that they have each adopted parts of Mr. Cooper's testimony. Thus, unlike Mr. Foley (vis a vis Ms. Crozier), the adoption of Mr. Cooper's testimony by other witnesses does not appear in the evidentiary record for this case. However, other parties' references to Mr. Cooper's testimony and exhibits should be taken as references to the testimony and exhibits of either Mr. Fix or Mr. Hooper.

[11] *See* note 8, *supra*.

Mr. Ryan Boutet, Public Utilities Engineer, Electric Operations Section, Energy Operations Division, discusses DTE Electric's vehicle fleet maintenance expenditures and base capital programs at 6 Tr 5128-5139.

Ms. Jessica Duell, Public Utilities Departmental Analyst, Electric Operations Section, Energy Operations Division, discusses expenditures on tree trimming and service restoration programs at 6 Tr 5140-5151.

Ms. Ally Durfee, Public Utilities Engineer, Electric Operations Section, Energy Operations Division, discusses strategic capital programs including infrastructure resilience, hardening, redesign, and modernization; and technology and automation at 6 Tr 5152-5159.

Mr. Nicholas M. Evans, Manager, Electric Operations Section, Energy Operations Division, discusses outage credits and the IRM at 6 Tr 5222-5238.

Ms. Lisa M. Kindschy, Public Utilities Engineering Specialist, Energy Cost Recovery and Generation Operations Section, Energy Operations Division, discusses capital expenditures and O&M expenses for steam power generation, MERC & Fuel Supply, nuclear generation, and other power generation at 6 Tr 5172-5190.

Mr. Cody S. Matthews, Public Utilities Engineering Specialist, Interconnection and Distributed Energy Resources Section, Energy Operations Division, discusses the commercial and industrial (C&I) battery DR pilot, the distributed generation (DG) program, and the non-wires alternative (NWA) pilots at 6 Tr 5160-5171.

Ms. Lauren Fromm, Manager, Data Access, Privacy and IT Section, Customer Assistance Division, discusses other miscellaneous capital expenditures including for environmental management at 6 Tr 5091-5097.

Ms. Brittney Klocke, Senior Analyst, Data Access, Privacy and IT Section, Customer Assistance Division, discusses communication and outage map issues at 6 Tr 5098-5105.

Ms. Danielle R. Rogers, Departmental Analyst, Data Access, Privacy and IT Section, Customer Assistance Division, discusses IT project related expenses and expenditures at 6 Tr 5106-5127.

Ms. Elaina M. Braunschweig, Departmental Analyst, Rates and Tariff Section, Regulated Energy Division, discusses the low-income assistance (LIA) credit, the residential income assistance (RIA) credit, and the residential senior citizen (RSC) credit at 6 Tr 3517-3580.

Mr. Justin J. Hecht, Auditor, Revenue Requirements Section, Regulated Energy Division, discusses total rate base for the test year, and projected depreciation and amortization expense and property tax expense at 6 Tr 4882-4891.

Mr. David W. Isakson, Departmental Analyst, Rates and Tariff Section, Regulated Energy Division, discusses present revenue, electric rate design, and tariff recommendations at 6 Tr 4892-4916.

Ms. Theresa L. McMillan-Sepkoski, Audit Specialist, Revenue Requirements Section, Regulated Energy Division, discusses adjustments to the employee incentive compensation plan (EICP) and to other O&M expense categories at 6 Tr 4917-4929.

Mr. Robert F. Nichols II, CPA, Manager, Revenue Requirements Section, Regulated Energy Division, discusses projected revenue deficiency, operating income, and the return on the Monroe regulatory asset at 6 Tr 4930-4938.

Mr. Mark J. Pung, Departmental Specialist, Rates and Tariff Section, Regulated Energy Division, discusses allocation issues and the class COSS, capacity costs, customer charges, and the IRM at 6 Tr 4939-4952.

Mr. Nicholas M. Revere, Manager, Rates and Tariff Section, Regulated Energy Division, discusses fleet electrification programs and the state reliability mechanism (SRM) capacity charge at 6 Tr 4953-4984.

Mr. Shannon Rueckert, Auditor, Revenue Requirements Section, Regulated Energy Division, discusses the tree trim regulatory asset, uncollectible expenses, and other employee-related O&M expenses at 6 Tr 4985-4997.

Ms. Michelle L. Schreur, Manager, Income Analysis Unit, Revenue Requirements Section, Regulated Energy Division, discusses overall projected O&M expense at 6 Tr 4998-5004.

Mr. Joseph E. Ufolla, Financial Analyst, Revenue Requirements Section, Regulated Energy Division, discusses capital structure balances and corresponding cost rates and the ROE at 6 Tr 5005-5028.

The following intervenors filed direct testimony as described below:

Attorney General: Mr. Sebastian Coppola, independent business consultant, discusses rate base and capital expenditures, the cost of capital, working capital, O&M expenses, and the revenue deficiency at 6 Tr 3584-3736.

CUB and MEC: Mr. Matthew Bandyk, Consultant, 5 Lakes Energy, discusses the inflation factor and the cost of capital at 6 Tr 3737-3764; and Mr. Graham G. Woolley, Consultant, 5 Lakes Energy, discusses transformer ratings and transformer aging at 6 Tr 3833-3855.

CUB, MEC, and NRDC: Mr. Joshua W. Denzler, Consultant, 5 Lakes Energy LLC, discusses the SRCSM, vegetation management, the contribution in aid of construction (CIAC), staffing issues, and allocation issues at 6 Tr 3765-3781 (Mr. Denzler's confidential testimony appears in Confidential Record Vol. 6); and Mr. David L. Gard, Senior Consultant, 5 Lakes Energy, discusses load profiles and building electrification issues at 6 Tr 3819-3832.

MEC and NRDC: Mr. Roger G. Colton, Owner, Fisher Sheehan & Colton, Public Finance and General Economics, discusses the affordability of DTE Electric rates for low-income customers, the LIA and RIA credits, and the arrearage management program at 6 Tr 3856-3913.

MNSC: Mr. Douglas B. Jester, Managing Partner, 5 Lakes Energy, discusses outage credits, securitization and tree trimming, allocation of production plant costs, rate design, and transportation electrification at 6 Tr 3782-3831 and 6 Tr 4032-4041.

Electrify America: Ms. Rhiannon Davis, Director of Government Affairs for Electrify America, discusses direct current fast charging (DCFC) deployment at 6 Tr 4762-4781; and Mr. Jigar J. Shah, Director of Energy Services for Electrify America, discusses EV fast charger rates and CIAC, and the General Service D3 rate at 6 Tr 4781-4793.

The DAAOs: Ms. Elizabeth Jacob, Skadden Fellow and Staff Attorney, Sugar Law Center for Economic and Social Justice, discusses her experience providing legal services to ratepayers struggling with affordability at 6 Tr 4632-4664; Ms. Toyia Watts, President, Charlevoix Village Association, discusses her experience as a DTE Electric customer at 6 Tr 4665-4698; Ms. Delores Orr, retired Vice President of the East Village Association and retired President of the Cadillac Blvd. Block Club, discusses her experience as a DTE Electric customer at 6 Tr 4699-4717; Dr. Yunus Kinkhabwala, Ph.D., Senior Scientist, PSE Healthy Energy, discusses the range of affordability issues facing DTE Electric customers at 6 Tr 4528-4568; Dr. Arjun Makhijani, Ph.D., President, Institute for Energy and Environmental Research, discusses affordability and resiliency in the time of climate change at 6 Tr 4569-4631; Mr. Justin Schott, Director, Energy Equity Project, University of Michigan School for Environment and Sustainability, discusses an equity framework for the Commission's decision-making processes at 6 Tr 4448-4527; and Mr. Jackson

Koeppel, independent consultant, discusses a just and equitable energy transition, affordability, and infrastructure quality at 6 Tr 4369-4447.

EVgo: Ms. Lindsey R. Stegall, Senior Manager, Market Development and Public Policy for EVgo, discusses EV charging issues and DCFC infrastructure at 6 Tr 3286-3327.

Energy Michigan: Mr. Alexander J. Zakem, Consultant, discusses the SRM capacity charge at 6 Tr 4163-4211.

Ann Arbor: Ms. Tiffany Giacobazzi, Urban Forestry and Natural Resources Planning Coordinator for Ann Arbor, discusses tree trimming and the impact of tree health on power outages at 6 Tr 4212-4221; Mr. Cyrus Naheedy, Transportation Engineer for Ann Arbor, discusses streetlight conversions at 6 Tr 4222-4232; Ms. Skye Stewart, Chief of Staff, Public Services Administration, Ann Arbor, discusses coordination practices with respect to utility work done in rights-of-way (ROW) at 6 Tr 4233-4242; and Dr. Melissa Stults, Sustainability and Innovations Director, Ann Arbor, discusses DTE Electric's reliability performance and its role in setting the ROE, outage credits, the SRCSM, incentive compensation, load, coordination efforts, streetlights, rebates, and pilots at 6 Tr 4243-4278.

GLREA: Mr. John Richter, Board of Directors, GLREA, discusses time-of-use (TOU) rates, DR, outage credits, and battery deployment at 6 Tr 4794-4864; and Mr. Robert Rafson, Member, GLREA, and Owner, Chart House Energy, discusses outages, microgrids, and nanogrids at 6 Tr 4865-4881.

ABATE: Mr. James R. Dauphinais, Managing Principal, Brubaker & Associates, Inc., discusses the projected test year, the IRM, and the Midcontinent Independent System Operator, Inc. (MISO) locational marginal price (LMP) at 6 Tr 3365-3417; Ms. Jessica A. York, Principal, Brubaker & Associates, Inc., discusses projected capital expenditures and O&M expense, including incentive compensation, at 6 Tr 3328-3364; and Mr. Christopher C. Walters, Principal, Brubaker & Associates, Inc., discusses the proposed ROE at 6 Tr 3418-3504.

Walmart: Ms. Lisa V. Perry, Director, Utility Partnerships, Regulatory, for Walmart, discusses the proposed ROE, the COSS, Rate Schedule D11, the IRM, and EV rates at 6 Tr 4718-4743.

ITC: Mr. Kwafo Adarkwa, Director of Public Affairs, Michigan Business Unit, ITC, discusses the EV charging pilot, and load growth issues at 6 Tr 4744-4750; and Mr. Pushkar Chindhade, Principal Operations Engineer, ITC, discusses the blackstart resource investment at 6 Tr 4751-4761.

AGMN: Mr. Paul J. Alvarez, Lead, Wired Group, discusses capital spending and the financial, policy, and regulatory issues affecting the electric distribution system at 6 Tr 3914-3981; and Mr. Dennis Stephens, independent consultant, discusses the DGP and the IRM at 6 Tr 3982-4044 (Mr. Stephen's confidential testimony appears in Confidential Record Vol. 6).

MI-MAUI: Mr. Richard Bunch, Executive Director, MI-MAUI, Senior Consultant, 5 Lakes Energy, discusses customer billing practices, project coordination, and streetlighting rates and tariffs at 6 Tr 4279-4368 (Mr. Bunch's confidential testimony appears in Confidential Record Vol. 6).

MEIU: Dr. Laura S. Sherman, President, MEIBC and IEI, discusses DTE Electric's EV related proposals and the C&I battery storage pilots at 6 Tr 4045-4129 (Dr. Sherman's confidential testimony appears in Confidential Record Vol. 6); and Mr. Justin R. Barnes, President, EQ Research LLC, discusses opt-in TOU rates for C&I customers at 6 Tr 4130-4162.

The CEOs: Mr. William D. Kenworthy, Regulatory Director, Midwest, for Vote Solar, discusses distribution planning, benefits cost analysis (BCA), and energy justice at 6 Tr 3187-

3234; Mr. Curt Volkmann, President, New Energy Advisors, LLC, discusses distribution planning at 6 Tr 3235-3266; and Mr. Boratha Tan, Regulatory Manager, Midwest, for Vote Solar, discusses the benefits of regression analysis and the CEOs' work with DTE Electric and the Staff on this issue at 6 Tr 3267-3285.

B. Rebuttal Testimony

The following rebuttal testimony was filed by DTE Electric:

Mr. Bellini rebuts MI-MAUI's proposals regarding streetlighting and Ann Arbor's proposals regarding bill credits and assertions regarding DTE Electric's restoration performance.

Ms. Bennett rebuts the Staff, the Attorney General, MNSC, AGMN, MEIU, Ann Arbor, Electrify America, and EVgo, on the topic of EVs.

Mr. Burgdorf rebuts Energy Michigan and the Staff on the topic of the SRM capacity charge and ABATE's tariff proposals.

Mr. Davis rebuts the Staff and the Attorney General on the topic of nuclear generation capital spending.

Mr. Deol rebuts AGMN, Ann Arbor, the DAAOs, the Attorney General, MNSC, and ABATE on the topic of capital expenditure disallowances, including for conversion projects, subtransmission redesign and rebuild, undergrounding, and infrastructure redesign and modernization.

Ms. Elliott Andahazy rebuts AGMN on the topic of capital expenditure disallowances, including for strategic capital, hardening, poles and pole top maintenance and modernization (PTMM),[12] breaker replacement, and undergrounding.

[12] For ease of reference, "PTMM" is used as an acronym encompassing both poles and pole tops.

Mr. Farrell rebuts the Staff and MEIU on the topic of the C&I battery storage pilot, Ann Arbor on the topic of the residential generator DR pilot, and GLREA, the CEOs, and the Staff on certain DR proposals.

Mr. Fix rebuts the Attorney General, the Staff, and ABATE on the topics of incentive compensation and O&M expense, and the Attorney General and CUB, MEC and NRDC on the topic of the voluntary separation incentive.

Mr. Foley rebuts the Staff; Ann Arbor; MNSC; CUB, MEC, and NRDC; GLREA; the DAAOs; ABATE; AGMN; Walmart; the Attorney General; and CUB and MEC on the topic of adjustments to capital expenditures and O&M expenses, including for reliability performance, outage credits, the IRM, the SRCSM, inflation, corporate memberships, the test year, and incentives.

Ms. Guillaumin rebuts the Attorney General, ABATE, and the Staff on the topic of capital spending disallowances, and GLREA's proposals for a battery energy storage system (BESS).

Ms. Hartwick rebuts AGMN and the Staff on the topic of capital spending disallowances including for distribution automation (DA), grid automation telecommunications, and NWAs.

Mr. Hatsios rebuts the Attorney General and the DAAOs on the topic of IT capital disallowances, MEIU's proposals regarding C&I TOU rates, MI-MAUI's proposals regarding kiosk payments, and the Staff's proposals regarding updates related to customers' outage experience.

Mr. Hill rebuts the Attorney General, the Staff, ABATE, Ann Arbor, and CUB, MEC, and NRDC on the topic of capital spending disallowances, including for emergent replacements, customer connections and relocations, portable generators, storm response performance, and CIAC.

Mr. Hooper rebuts the Staff and the Attorney General on the topic of healthcare benefits and expense.

Mr. Kryscynski rebuts the Staff, AGMN, Ann Arbor, MI-MAUI, the DAAOs, and the CEOs on the topics of reliability and capital investments, outages, BCAs, the GPM, hardening, changes in spending over time, EVs, environmental justice, coordination with municipalities, and distribution pilots.

Mr. Lepczyk rebuts the Staff, the Attorney General, ABATE, and AGMN on the topics of capital structure, cost rates, and securitization.

Mr. Maroun rebuts MNSC and the Staff on the topic of the COSS, and Energy Michigan on the topic of the SRM capacity charge.

Mr. Sharma rebuts the Staff and the Attorney General on the topic of IT-related capital spending and O&M expense disallowances, and MEIU on the topic of IT-related planning.

Mr. Sparks rebuts the Staff on the topics of uncollectibles and the LIA/RIA credits, the DAAOs regarding DTE Electric's relationship with state and community agencies, the CEOs' proposals regarding the MiEJScreen mapping tool, MI-MAUI on the topic of cash payments, and MEC and NRDC regarding the LIA/RIA credits.

Ms. Steudle rebuts the Attorney General, AGMN, and Ann Arbor on the topics of tree trimming and future required analysis.

Ms. Uzenski rebuts the Staff's proposals regarding adjustments to IT O&M, fleet vehicle capital spending, and certain benefits expense adjustments; the Attorney General on the topics of fleet vehicles, office space, in-service dates, the Ludington regulatory asset, and incentive compensation; and AGMN on the topic of capitalizing tree trim expense.

Dr. Villadsen rebuts the Staff, the Attorney General, ABATE, Walmart, Ann Arbor, and CUB and MEC on the topics of the cost of capital and the ROE.

Mr. Willis rebuts the Staff on the topic of the RSC; MNSC's proposals regarding cost of service classes, space heating costs, and rate design; the DAAOs' proposals regarding Rate D1.6; MEIU's proposals regarding C&I TOU rates; GLREA's proposals regarding nanogrids and microgrids and cost allocation; and MEIU's and Electrify America's proposals regarding fast charger rates.

Ms. Wisniewski rebuts the Attorney General and ABATE on the topic of property tax expense.

The following rebuttal testimony was filed by the Staff and intervenors:

The CEOs: Mr. Kenworthy supports MNSC's and the DAAOs' proposals regarding electrification and affordability.

The DAAOs: Mr. Koeppel rebuts the Attorney General's and ABATE's ROE proposals, the CEOs' proposals regarding the GPM and environmental justice, and the Attorney General's BCA proposals with respect to capital expenditures.

Energy Michigan: Mr. Zakem rebuts the Staff's SRM capacity charge proposal.

ITC: Mr. Chindhade rebuts the Staff's and ABATE's proposals regarding the blackstart projects.

MNSC: Mr. Jester rebuts the Staff's EV proposals.

EVgo: Ms. Stegall rebuts the Staff's and the Attorney General's EV proposals, MNSC's rebate proposals, and Walmart's EV rate proposals.

Electrify America: Ms. Davis rebuts the Staff's and the Attorney General's EV proposals.

ABATE: Mr. Dauphinais rebuts MNSC's COSS proposals regarding demand and production and distribution rate design, and MEIU's proposals regarding the BCA for the TEP; Mr. Brian C. Andrews, Principal, Brubaker & Associates, Inc., rebuts the Staff's proposals regarding the allocation of capacity costs at 6 Tr 3505-3516; and Mr. Walters rebuts the Staff's proposals regarding the ROE and the ROR.

MEIU: Dr. Sherman rebuts the Staff's and the Attorney General's proposals regarding EVs.

The Staff: Ms. Anne T. Armstrong, Division Director, Customer Assistance Division, rebuts the DAAOs' proposals regarding shutoffs, arrearages, and non-energy benefits at 6 Tr 5209-5221; Ms. Braunschweig rebuts the DAAOs', the CEOs', and MEC and NRDC's proposals regarding affordability and the LIA/RIA credits; Mr. Isakson rebuts GLREA's pilot proposals, the CEOs' regression analysis proposal, the DAAOs' proposal regarding the LIA credit, MNSC's proposals regarding residential electric heating rates, the proposals made by CUB, MEC, and NRDC regarding the rate structure for electric heating, and Ann Arbor's proposals regarding streetlighting conversions; Mr. Kevin S. Krause, Gas Cost of Service Specialist, Rates and Tariff Section, Regulated Energy Division, rebuts the DAAOs', GLREA's, and the CEOs' proposals regarding community solar and microgrids, and Electrify America's, MEIU's, and Walmart's proposals regarding EV rates and tariffs and the rate design for EV charging at 6 Tr 5191-5208; and Mr. Revere rebuts Energy Michigan's SRM capacity charge proposals, and MNSC's, Electrify America's, Ann Arbor's, MEIU's, and EVgo's EV-related proposals.

III. <u>LEGAL STANDARDS</u>

In its initial brief, DTE Electric notes that it carries the burden of proof to show that its proposals are just and reasonable by the preponderance of the evidence standard. DTE Electric's initial brief, p. 10. DTE Electric states that the Commission is obligated to establish rates that recognize both increasing and decreasing costs, and contends that the "Commission has an obligation to facilitate DTE Electric's financial health for the benefit of its electric customers and shareholders." *Id*., p. 14 (citations omitted). The company argues that it is unconstitutional to "use hindsight or otherwise base DTE Electric's rate on past events." *Id*., p. 15. DTE Electric further argues that there is no legal basis for advancing "what certain intervenors may consider to be appropriate policy changes that are beyond the scope of this case, and the Commission's jurisdiction generally." DTE Electric's reply brief, p. 6.

The Attorney General likewise notes that the utility carries the burden of proof by the preponderance of the evidence standard, and that the Commission has found that rate base projections must be supported by sufficient evidence. Attorney General's initial brief, pp. 8-9. The Attorney General notes that the burden of proving reasonableness and prudence always remains with the utility, and adds that, "[d]ue to the information asymmetry that exists between a utility and its captive customer base, the regulator must necessarily hold the requesting utility accountable for supporting its requests." Attorney General's reply brief, p. 4. In response to the company's assertions about its financial health, the Attorney General contends that "a public utility is entitled to a reasonable return of and on its investments, [and] the Commission's obligation is to facilitate an environment where that can happen." *Id*., pp. 4-5 (footnote omitted).

MNSC contends that DTE Electric's comment about hindsight lacks context and "appears misleading to the extent it suggests the Commission should not consider the Company's history of past revenue earnings." MNSC's reply brief, pp. 2-3. MNSC argues that the Commission may properly consider historic excessive returns and unaffordability for customers. The CEOs note that, while the Commission is not authorized to "make management decisions for utilities . . . the Commission has broad authority to regulate rates under Chapter 460 of the Michigan Compiled

Laws." CEOs' initial brief, p. 7 (citations omitted). The DAAOs also take note of the Commission's broad discretion in setting just and reasonable rates, as rate setting is a quasi-legislative function which is not bound to any single formula or method. DAAOs' initial brief, pp. 8-9.

An accurate description of the legal standards applied by the Commission in a rate proceeding can be found in the March 1, 2024 order in Case No. U-21389, pp. 3-4 (quoting the Proposal for Decision in that case, pp. 18-19). The Commission finds that, having applied those standards, its final decision in this case is based on a proper application of the law and weighing of the evidence in the record, represents the appropriate balance between customer and shareholder interests in the ratemaking process of fixing just and reasonable rates, and ensures that the utility has the opportunity to earn a reasonable return of and on its investments in this matter. *See, Bluefield Waterworks Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Fed Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944); *Michigan Bell Tel Co v Mich Pub Serv Comm*, 332 Mich 7, 38; 50 NW2d 826 (1952).

IV. TEST YEAR

In developing its requested rates for this proceeding, DTE Electric relies on a projected test year from January 1, 2025, through December 31, 2025 (test year) based, in part, on the 2022 historical year adjusted for known and measurable changes; and the bridge period is January 1, 2023 through December 31, 2024. ABATE objects to the use of the fully projected test year (as opposed to an historical test year) on grounds that it increases the complexity and frequency of rate cases, disincentivizes cost containment, and introduces an excess of information that cannot be known with adequate certainty. ABATE's initial brief, pp. 3-9. ABATE argues that the projected test year results in excessive over-recovery for the utility as shown by DTE Electric's report of a revenue sufficiency of $80.5 million in the historical year in the instant case. *Id*., pp. 3, 5; 6 Tr 3370-3379. ABATE notes that, where the utility fails to substantiate its projections with record evidence, the Commission may choose an alternative method for arriving at the projection, such as use of the historical test year adjusted for known and measurable changes. ABATE argues that "given practical procedural realities, the use of projected test years will necessarily result in interested parties missing or failing to adequately challenge unreasonable and inappropriate cost projections which will ultimately be collected from customers." ABATE's initial brief, p. 6. ABATE contends that, if the Commission decides to consider projected costs, it must be diligent in holding the company to its burden of proof.

DTE Electric counters that ABATE made the same arguments in Case Nos. U-20836 and U-21297 where they were rejected based on the plain language of MCL 460.6a. The company notes that the Commission's decision on this issue has been affirmed by the Court of Appeals. DTE Electric's initial brief, p. 17. DTE Electric posits that ABATE simply disagrees with the "Legislature's choice to reduce regulatory lag[.]" DTE Electric's reply brief, p. 7.

In reply, ABATE argues that the company's assertions are inconsistent with the statute because rates must be just and reasonable, and ABATE notes that MCL 460.6a provides that the company "may" rely on projections. ABATE's reply brief, pp. 1-2. ABATE points to DTE Electric's consistent test year sufficiencies and argues that they speak for themselves. *Id*., p. 4 (citing Table JRD-1 provided at 6 Tr 3371).

MNSC replies that they support ABATE's argument that projected test years have resulted in over-recoveries. MNSC's reply brief, p. 4. MNSC asks the Commission to be more diligent in ensuring that the burden of proof is met, arguing that both the IRM and the projected test year "reduce the Commission's practical ability to disallow unreasonable spending once spending levels are approved – even if the spending fails to produce promised benefits." *Id.*, p. 5. MNSC argues that increasingly complex cases burden ratepayers more than they burden shareholders, and that "the voluminousness of the record says nothing about the quality of evidence supporting DTE spending projections." *Id.*, pp. 5-6.

Regarding the projected test year, the Attorney General makes the following observations:

> Despite filing this case in late March of 2024, DTE used a historical test year of 2022, meaning that its numbers were already more than a year stale when it filed this case. While the AG has, where applicable, recommended some commonsense adjustments based on updated information in this case, overall, the process makes more work for Staff, Intervenors, and the Commission, and it continues to inject more uncertainty into review, which allows DTE to make more and more tenuous "projections."

Attorney General's reply brief, p. 8.[13]

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.

[13] The Commission notes that references to "DTE" in quoted material are to DTE Electric unless otherwise noted, and references to "AG" in quoted material are to the Attorney General.

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.

V. RATE BASE

Rate base[14] consists of the capital invested in used and useful utility plant, less accumulated depreciation, plus the utility's working capital requirements. DTE Electric initially projected a total electric rate base of $22.108 billion (later revised to $22.1 billion) which consists of $20.8 billion of net plant and $1.295 billion of working capital. The Staff proposed a total electric rate base of $21.97 billion. DTE Electric maintains that it is "pursuing multi-year strategic initiatives to (1) rebuild, modernize, and automate its 46,000 miles of electric circuits (the 'grid') to achieve reliability that is better than industry average by 2029, and (2) replace aging coal plants with modern power-generation assets, such as wind turbines, large-scale solar arrays, and large battery installations." DTE Electric's initial brief, p. 1 (footnote omitted). DTE Electric states that this effort will require significant investment and the company urges the Commission not to adopt any disallowances.

DTE Electric avers that its revenue request will result in a billed increase of 37 cents per day for the average residential customer. *Id*., p. 2, n. 2. DTE Electric states that its residential electric bills were 11% below the national average in 2022 and 13% below that average in 2023, and the

[14] The sequence in which issues are addressed in this order generally follows the sequence in which they are addressed in DTE Electric's initial brief. All revenue-related decisions have been accounted for in arriving at the revenue deficiency and other decisions, whether or not the issue appears within the revenue-related sections of this order.

increase proposed in the instant case will continue a trend of keeping average bill growth below average inflation.

DTE Electric originally projected a revenue deficiency of $456.4 million; in its initial brief, the company revises the request to $446.1 million. *Id*., Attachments A and B. In its reply, DTE Electric revises its request to $441.0 million. DTE Electric's reply brief, p. 4, and Attachments A and B.

Addressing rate base as a whole, the Attorney General argues that, since 2011, capital expenditures by the company have tripled; and rate base has more than doubled in the past 10 years. 6 Tr 3594-3595; Attorney General's initial brief, p. 11. The Attorney General argues that this unbridled growth has two main drivers: (1) "necessary replacement of aging infrastructure and new capital spending to address market growth[;]" and (2) "the opportunity to increase earnings growth" which is "directly related to rate base growth, dividend growth, and stock price appreciation for shareholders." *Id*., p. 12. The Attorney General posits that Exhibit AG-1, a March 8, 2022 Investor Presentation by the company, shows that the "increase in earnings comes almost entirely from the increase in capital expenditures and rate base." *Id*.

Ann Arbor also argues that the requested rate increase is neither necessary nor reasonable. Ann Arbor's initial brief, pp. 2-3; Ann Arbor's reply brief, pp. 1-3. Ann Arbor notes that DTE Electric's

> All Weather SAIDI [system average interruption duration index] for the three-year period from 2021 through 2023 was more than double that of the three-year period from 2018 through 2020 (1,018 minutes versus 448 minutes) (Kryscynski, 3 Tr 311, Figure 2), and the All Weather SAIFI [system average interruption frequency index] for the same two three-year periods increased by over 13% (1.34 for 2018-2020 versus 1.52 for 2021-2023). Kryscynski, 3 Tr 312, Figure 4.

Id., p. 2. Ann Arbor argues that performance has decreased while rates have increased. Regarding the average bill, Ann Arbor asserts that "when the cost of electricity is compared in a more meaningful way – by unit – it is apparent that DTE customers (in particular, residential customers) are actually paying some of the highest rates per kWh [kilowatt-hour] in the nation. See, Stults, 6 Tr [4251]; Ann Arbor's Initial Brief, p. 2-3." Ann Arbor's reply brief, p. 2.

MNSC also argues that DTE Electric is wrong in asserting that this rate increase comes at a reasonable cost, noting that the company's residential rates "are among the highest nationally – in the fourth quartile and higher than Michigan generally and Great Lakes peers[.]" MNSC's reply brief, pp. 1-2 (citing the residential rate comparison by state located at Exhibit MEC-2, p. 4).

The parties' proposed adjustments to DTE Electric's projected rate base are addressed below.

A. Working Capital

DTE Electric projects working capital at $1.295 billion. The Staff proposed a reduction to working capital of $6.1 million related to other accounts receivable, which the company accepted. DTE Electric's initial brief, pp. 19-20.

1. Ludington Regulatory Asset

DTE Electric includes in working capital $9.9 million for a regulatory asset account that accrues amounts related to the defective work done by Toshiba America Energy Systems Corporation (Toshiba) at the Ludington Pumped Storage Plant (Ludington). Exhibit A-12, Schedule B4.

The Attorney General argues that this amount should be removed from working capital because DTE Electric should not earn a return on the deferred amount until the Commission has determined how much of the total deferred amount the company should recover. 6 Tr 3641; Attorney General's initial brief, pp. 77-78. The Attorney General argues that:

> the Company is not willing to admit to refunding the return on disallowed Ludington deferred costs. It would be difficult for the Commission to disallow prior earned returns in the future, without the Company claiming prohibitive retroactive ratemaking. Therefore, the AG's recommendation to remove those

> costs from rate base and provide a future return on the allowed base costs is the appropriate treatment of those deferred costs.

Id., p. 78 (citing Exhibit AG-61, p. 3). The Attorney General asserts that this issue is still playing out between the company and other parties, for example in power supply cost recovery (PSCR) cases. Attorney General's reply brief, p. 9.

DTE Electric counters that the Commission approved the Ludington regulatory asset in the May 18, 2023 order in Case No. U-21310 (May 18 order), and the company should be able, under established accounting practice, to timely recover the financing costs related to costs incurred as a result of the defective work. DTE Electric's initial brief, p. 20; DTE Electric's reply brief, p. 10. The company asserts that regulatory assets are generally included in working capital. The company notes that none of the costs recorded to the regulatory asset are being recovered in a PSCR proceeding. 6 Tr 1569. DTE Electric refers to Ludington as "a fundamental piece of clean energy advancement." 6 Tr 1568.

Pursuant to the May 18 order, p. 5, DTE Electric is authorized to defer certain costs and the estimated liquidated damages associated with allegedly defective work performed by Toshiba at Ludington, which has given rise to several years of dispute between DTE Electric and Toshiba. The $9.9 million represents the balance in the deferred account as of December 3, 2023. Exhibit AG-19.

The Commission agrees with DTE Electric that regulatory assets are generally included in working capital. While there are exceptions to this general rule, they usually include some extenuating circumstances; otherwise financing costs associated with regulatory assets are typically eligible for recovery. In the present case, DTE Electric is currently involved in litigation resulting from allegedly defective work, and the Commission has already authorized DTE Electric to defer specified costs as the litigation plays out. While the Commission was clear that the approval for deferred accounting granted in the May 18 order was for accounting purposes only, and not a guarantee of recovery of financing costs, the Commission in the present proceeding finds that the ongoing litigation over Ludington does not rise to the extenuating circumstances that would warrant the removal of regulatory assets from the company's working capital balance. As such, the Commission declines to adopt the Attorney General's proposed $9.9 million disallowance. However, the Commission expresses its expectation that should the company ultimately successfully recover from Toshiba an amount that includes financing costs, the company will either refund such an amount to customers or use the recovered financing costs as an offset to potential future rate increase requests.

2. Time of Day Program

DTE Electric includes in working capital $5.78 million for the Time of Day (TOD) program. Exhibit A-12, Schedule B4.

The Attorney General argues that the company failed to show that the costs incurred in 2022 and 2023 for this program were reasonable and prudent and recommends that the full amount be removed from working capital along with $1.69 million in amortization expense. 6 Tr 3646-3647; Attorney General's initial brief, pp. 79-80.

DTE Electric counters that, in the December 1 order, the Commission approved the company's projected total of $8.5 million in capital expenditures on the TOD program for 2022 and 2023, plus a related $1.7 million in amortization expense. DTE Electric states that in the instant case it provided actual costs totaling $8.5 million for 2022 and 2023 ($2.4 million for 2022 and $6.1 million for 2023), showing there has been no change from the December 1 order. 6 Tr 2312-2313; DTE Electric's initial brief, p. 21; DTE Electric's reply brief, p. 11.

The Attorney General responds that the similarity to the cost projection in the December 1 order is irrelevant because the company failed to provide sufficient itemized, detailed data in support of the costs in the instant case. The Attorney General argues that between 2022 and 2023 DTE Electric forecasts a threefold increase for the addition of customer service representatives which is not supported in the evidence. Attorney General's reply brief, p. 10; Exhibit AG-22.

The Commission notes that DTE Electric provided the following testimony:

> Differences in 2022 and 2023 costs between Case No. U-21297 and Case No. U-21534 included reductions or offsets across Information Technology (IT), Customer Outreach and Customer Service. The 2022 variance between actual costs in Case No. U-21534 and projected costs in Case No. U-21297 involved a reduction in all three TOD expense line items, resulting in a $0.4 million reduction after accounting for TOD expenses prior to November 18, 2022. Projected costs for 2023 in Case No. U-21534 increased by $0.4 million in total, largely due to Customer Service overtime labor that was partially offset by a decrease in IT and Customer Outreach spending. The Customer Service overtime labor costs were required to perform billing and AMI [advanced metering infrastructure] meter rate conversion pre-work, manual intervention of placing customers on the new TOD rates, and for processing business exceptions related to delayed bills. Overall, there was essentially no variance in the total TOD costs of $8.5 million, that was approved for deferral in Case No. U-21297[.]

6 Tr 2312-2313. The Commission agrees that the amounts reported as actuals in the instant case are almost identical to the forecasts reported to have been included in the last rate case at 6 Tr 2312. The Commission finds the testimony describing the difference between 2022 and 2023 costs to be adequate and rejects the Attorney General's proposed disallowance to working capital for this cost category.

3. Incentive Compensation

DTE Electric includes in working capital $3.88 million in a regulatory asset, which represents the difference between the amount of incentive compensation related to operational metrics approved in Case No. U-20836 and the amount the company forecasted based on achieving the targeted results approved in that case. 6 Tr 1570; Exhibit A-12, Schedule B4.

The Attorney General argues that there is no recoverable balance for 2022; that 2023 actually involves a regulatory liability of $6.79 million; and that it is premature to forecast a balance for 2024 because the company's performance is not known. Thus, the Attorney General proposes a $9.99 million total reduction to working capital. 6 Tr 3644-3645; Exhibit AG-20; Attorney General's initial brief, pp. 78-79. The Attorney General contends that the regulatory liability balance should be amortized over five years, and that working capital should include $1.36 million in negative amortization as a reduction to the forecasted O&M expenses for the test year. The Attorney General contends that DTE Electric attempts to "use the results of certain performance measures over 100% to compensate for underperformance in other measures. This is not the methodology accepted by the Commission in prior rate cases and should be rejected." *Id*., p. 79. The Attorney General argues that her proposed methodology conforms to the Commission's directives in Case No. U-20836. Attorney General's reply brief, pp. 10-11.

DTE Electric counters that the Attorney General does not understand how the incentive compensation tracker mechanism works. 6 Tr 1571-1574, 2901-2903; DTE Electric's initial brief, p. 22. DTE Electric argues that "a performance weighted average is the basis for the actual incentive compensation plan payouts that recognizes there are gradients[.]" 6 Tr 1572. The company contends that the Attorney General mistakenly applies a binary approach to whether the target was met, but actually "[t]here are also various gradients of performance between Threshold and Maximum." 6 Tr 1572; DTE Electric's reply brief, p. 11.

In the November 18 order, p. 301, the Commission adopted a two-way tracker for operational-related incentive compensation requiring a refund to customers if 60% of targeted metrics were not achieved, but allowing additional cost recovery up to 100% of targeted metrics, all of which is to be recorded as a regulatory asset or liability (depending on whether the percentage of metrics achieved is over or under 60% of target operational metrics). In the December 1 order, p. 239, the Commission continued this deferral treatment but lowered the base amount to 52% of targeted metrics. Also in the December 1 order, the Commission quoted the administrative law judge in that case as follows:

The ALJ stated:

> [I]n allowing DTE the possibility of recovering additional EICP [employee incentive compensation plan] [expense] associated with operational measures, the Commission in Case No. U-20836 did not intend to require ratepayers to provide DTE with a return on that potentially-deferred amount of incentive compensation, prior to a determination whether the operational targets for a given year actually were met.

December 1 order, pp. 173-174 (quoting the Case No. U-21297 PFD, p. 412). The Commission agreed with the judge, stating "[t]he Commission finds the ALJ's recommendation well-reasoned and supported by the record. The Commission indeed did not intend to require customers to provide the company a return on incentive compensation prior to knowing whether the targets for the company to pay this incentive compensation were even met." December 1 order, p. 174.

DTE Electric points out that the Attorney General started her calculation for 2023 with the incentive compensation forecasted by the company for 2023 in Case No. U-20836, but argues that, as a tracker, the calculation should start with 2023 actuals which are now available. 6 Tr 1571-1572. The company further argues that the Attorney General's calculations are incorrect because they do not reflect the fact that various performance targets are weighted, and they do not take the weighting into account. 6 Tr 1572-1573. The company also makes a case for a regulatory asset for 2022 and a liability for 2023, and argues that the correct deferral for 2022-2023 is a regulatory liability of $5.99 million as of December 31, 2023. 6 Tr 1573-1574. The company contends that, if the Commission approves the Attorney General's proposal to amortize the regulatory liability over five years, then "the annual credit to O&M should be $1.200 million (instead of the

$1.358 million proposed by Witness Coppola). This would result in a 2025 ending balance of $4.799 million and an average liability in working capital of $5.398 million. This is a $9.282 million reduction in working capital compared to the Company's filed position."
6 Tr 1574.

For rate base purposes, the Commission adopts DTE Electric's proposed $9.28 million reduction to working capital. This amount reflects the company's corrections to the Attorney General's calculations. Thus, the Commission agrees with the Attorney General's proposal to amortize the regulatory liability over five years, but disagrees with the Attorney General's reliance on forecasted amounts for 2023 rather than actuals. This amount reflects a regulatory asset of $750,000 for 2022 and a liability of $6.75 million for a net liability of $5.99 million as of December 31, 2023. 6 Tr 1572-1574. As the company states, even applying its weighted averaging, the actual 2023 outcome ranges from 33.6% to 52.7%. 6 Tr 1572. Consistent with the Commission's findings in the December 1 order, the Commission does not approve 2024 costs for regulatory asset treatment. The Commission declines to approve a return on an amount that may change significantly when actual data is available. The Commission approves the company's proposed $1.2 million credit to O&M. 6 Tr 1574.

The Commission observes that, while DTE Electric provided lengthy testimony describing the targets for the various operational measures and how the company scored itself in terms of proximity to each target, the testimony does not adequately explain the weighted averaging. *See*, 6 Tr 2881-2896. The company used the terms Target, Threshold, and Maximum. The Target appears to correspond to the percentage amount designated by the Commission in the November 18 and December 1 orders (60% and 52%, respectively). The Maximum represents 100% achievement of the relevant metric, and the Threshold appears to be the company's minimum target for the employee to achieve in order to receive some payout. As the Attorney General notes, the Commission's orders have referred only to the Target. The Commission is not averse to the concept of using gradations to incentivize employees to achieve the metrics, but finds that the testimony does not adequately explain the weighted averaging, how the weighting was tied to performance, or what dollars correspond to payouts for each level (Threshold, Target, Maximum). As DTE Electric describes it, "Exhibit A-35, Schedule Z1 shows that for the last five years, the actual weighted performance was 79.3% for the AIP [annual incentive plan], 81.5% for the AIP Executives, and 69.2% for the REP [rewarding employees plan], for a combined average of 76.6% (Fix, 6T 2901-2903)." DTE Electric's initial brief, p. 259. Use of a weighted average can be subjective, and the formulas applied in Exhibit A-35, Schedule Z1 are not obvious. In particular, the use of performance measures over 100% to compensate for underperformance on other measures needs to be more fully explained. The Commission agrees that a reasonable incentive plan may include payouts within a broader spectrum of performance levels than simply Target and Maximum, including over 100% of Maximum, but does not find that the weighted averaging has been adequately explained or supported in the instant case. The Commission notes that this issue is addressed further with respect to O&M expenses for incentive compensation, below.

In conclusion, the Commission finds that, pursuant to the decisions in this order, DTE Electric has a working capital balance of $1,279,873,000.

B. Capital Expenditures

DTE Electric reports 2022 capital expenditures of $2.6 billion, reports or projects bridge period capital expenditures of $5.2 billion, and projects test year capital expenditures of $2.6 billion. Exhibit A-12, Schedule B5.

1. Energy Supply

DTE Electric explains that, in this case, energy supply refers to fossil generation and energy storage assets, including hydraulic storage and BESSs. 6 Tr 1585; DTE Electric's initial brief, p. 23, n. 25. DTE Electric reports total energy supply costs of $459.4 million for 2022, $1.043 billion for the bridge period, and $460.4 million for the test year. *Id*., p. 23. Energy supply capital expenditures are divided into routine and non-routine projects, including major routine and major non-routine, and includes costs associated with compliance with the steam electric effluent limitations guideline rule and coal combustion residuals rule.

a. Belle River and Greenwood Projects

DTE Electric includes work on the Belle River and Greenwood generation units among routine maintenance projects greater than $1 million. Exhibit A-12, Schedule B5.1, pp. 6-7. The Attorney General proposes a disallowance of $13.27 million for 2024 for Belle River and $16.8 million for 2024-2025 for Greenwood ($8.58 million for 2024 and $8.22 million for the test year) based on applying inflation to a three-year average (2021-2023) of costs. 6 Tr 3618-3620; Attorney General's initial brief, pp. 29-31. The Attorney General notes that in discovery and in rebuttal the company admitted that the addition of these major maintenance projects (steam turbine replacements) in routine capital cost categories is unusual, since the projects are typically only done every 3-5 years. *Id*., p. 30 (citing Exhibit AG-53, pp. 4-5, and 6 Tr 1723-1724). The Attorney General proposes the disallowance based on the misclassification and the unusual forecast. The Attorney General states that she is not disputing whether this work should be done, but simply the forecasts which "inexplicably have routine capital expenditures doubling between 2023 and 2024." Attorney General's reply brief, p. 12. She notes that her projections are based on the three-year average of historical spending.

DTE Electric counters that the Attorney General provided no engineering analysis and did not actually evaluate the planned projects. The company notes that during the 2021-2023 timeframe, Belle River only had one outage and Greenwood only had a partial outage; but the projects planned for 2024-2025 involve two planned major maintenance outages for Belle River and one for Greenwood. 6 Tr 1722-1723; DTE Electric's initial brief, p. 25. The company argues that planned major outages are an important way to implement large capital projects, and thus annual spending varies depending on whether such outages occur during a particular year. DTE Electric states that it plans to replace the low pressure (LP) turbines on Belle River Unit 2 in 2024 and on Greenwood Unit 1 in 2025 due to industry-wide concerns with stress corrosion cracking. 6 Tr 1670-1671, 1723-1724. DTE Electric argues that the Attorney General's reduction is simplistic. DTE Electric's reply brief, pp. 11-12.

The Commission approves DTE Electric's proposed costs. Regarding the Belle River Unit 2 LP turbine rotors and blades, DTE Electric provided testimony that "[i]nspections have identified blade erosion and rotor cracking that needs to be addressed to ensure continued safe and reliable operation of the LP turbines. This work is a permanent fix to the issues identified and repaired on a temporary basis in 2020." 6 Tr 1670-1671. For the Greenwood Unit 1 LP turbine rotors and blades, DTE Electric indicates that "[s]tress corrosion cracking of multiple blade root connections is being addressed to ensure continued safe and reliable operation of the LP turbines." 6 Tr 1673. This work is identified under the category of routine projects with projected costs greater than $1 million for 2024 for steam power. The company explained that the amounts are exceeding the Attorney General's average due to the difference in the number of planned outages and the projects that are expected to be carried out during each outage. 6 Tr 1722-1723. DTE Electric adds that this "turbine maintenance is routine in nature but infrequent as evidenced by this being the first time the LP turbines have been replaced in the history of these plants" and the rotors are about 40 years old. 6 Tr 1723-1724. The Commission finds this evidence to be adequate to support the planned spend.

b. Blue Water Energy Center Conference Room Building Project

DTE Electric seeks recovery of $3.3 million associated with the construction of the Blue Water Energy Center (BWEC) Conference Room Building. Exhibit A-12, Schedule B5.1, p. 6. The Commission excluded this project from rate base in the December 1 order, pp. 37-38. DTE Electric contends that, in the instant case, it has justified the project, which is needed in order to provide additional workspace during both routine and major maintenance activities when a large number of support personnel must be onsite. DTE Electric posits that the project is supported by Exhibit A-34, Schedule Y1, which contains an analysis comparing the project to other options such as purchasing or renting trailers. DTE Electric's initial brief, pp. 26-27. The company contends that the analysis shows that it will save over $10 million over the life of the plant by constructing the conference room. *Id*., (citing 6 Tr 1699-1700, 1725-1726); DTE Electric's reply brief, p. 12.

ABATE argues that the conference room spend should be excluded again based on the same lack of evidence which concerned the Commission in the last rate case. 6 Tr 3354-3355; ABATE's initial brief, pp. 12-13. ABATE argues that the company has failed to explain why adequate office space was not included in BWEC's original design. ABATE also argues that the cost assumptions used in DTE Electric's alternatives analysis are not supported or even discussed on the record. ABATE contends that DTE Electric simply inputs assumptions into an Excel model without support or documentation. ABATE's reply brief, p. 8.

In the December 1 order the Commission stated:

> The company failed to provide sufficient detail to justify this project and failed to respond to inquiries with sufficient detail to demonstrate the definitiveness of or need for this project. *See*, 4 Tr 1134; 6 Tr 3717; Exhibit AB-7, pp. 38-40. Moreover, DTE Electric's comparisons of this project to its other power plant facilities reinforces the obvious question raised by the Attorney General of why the company's planned conference room [was] not included in the original design of the BWEC site if all of the company's power plant facilities require such conference facilities. The company's response did not shed light on this reasonable question or provide enough information to discern whether the current facilities are inadequate to serve such a purpose.

December 1 order, pp. 37-38. The Commission has studied Exhibit A-34, Schedule Y1, but is not persuaded that it answers the questions posed by the December 1 order. In response to discovery from the Staff, DTE Electric indicates that the conference room "was not needed at the time" of initial construction; that BWEC has an open air design that allows for "significantly less inherent building square footage as compared to other major DTE Electric power plants[;]" and that, while BWEC has 25 available workspaces for full-time employees, it actually needs to accommodate "surges of 100-plus" onsite workers to support "routine" and major activities. Exhibit A-34, Schedule Y1, p. 1. Additionally, "[r]outine maintenance activities are expected twice every year[.]" *Id*., p. 3. The temporary trailers used by the construction company were removed when construction was completed. *Id*., p. 2. This seems like something the company could have anticipated. DTE Electric avers that its analysis shows that the cost of future trailer use will exceed $15 million. *Id*., pp. 4-8. The analysis includes the years 2024-2052, and shows total estimated annual trailer rental costs plus O&M costs for either single-wide trailer rentals or double-wide trailer purchases with some rentals. Dollar amounts are provided, but no explanation of what they relate to or how they were sourced. *Id.* The evidence does not support the spending request. The Commission finds that this issue could and should have been addressed at the time of construction, and that the evidence provided in this case purportedly showing the cost effectiveness of the building over trailer rentals is insufficient. The Commission adopts ABATE's proposed disallowance.

c. Commission Staff Adjustments Based on Actual Expenditures

Based on the difference between DTE Electric's projected expenditures for the November 2023 to April 2024 time period and the company's actual expenditures for that time period, the Staff proposes to update certain expenditures for steam generation, both routine and non-routine, to reflect a net $21.33 million reduction to rate base for routine capital projects and a $5.1 million reduction for non-routine capital projects (blackstart projects are also discussed separately below). 6 Tr 5178-5180, 5052; Staff's initial brief, pp. 15-18; Exhibit A-12, Schedule B5.1; Exhibit S-16.0. The Staff notes that the company's as-filed case reflects actual expenditure amounts through October 2023, but that updated information provided during discovery can now take those amounts through April 2024. Exhibit S-16.0. On that basis, the Staff proposes the following bridge period reductions: (1) $3.71 million for steam non-routine (6 Tr 5178); and (2) $21.33 million for steam routine (6 Tr 5179-5180). Staff's initial brief, pp. 15-18. Based on updated project sheets showing lower projections for 2025, the Staff also proposes a reduction of $1.9 million for Monroe Bottom Ash Conversion (6 Tr 5179). *Id*.

DTE Electric counters that the variance between the projected amounts that appear in exhibits and the actual spends should not be the deciding factor because "[c]apital projects are managed on a total beginning-to-end basis" and "[t]here can be monthly timing differences that can shift spending between months during project execution." DTE Electric's initial brief, p. 27. The company argues that the entire portfolio of projects will meet the overall projected spend during the full time period. 6 Tr 1728-1729. The company contends that if the Staff's approach was applied across the board, non-routine expenditures would increase by over $14 million, making the application inconsistent. 6 Tr 1729; Exhibit A-34, Schedule Y2; DTE Electric's reply brief, p. 12. The company does not mention how this consistency argument would affect routine capital expenditures.

The Staff responds that it does not question the necessity of these projects, but that "the timing of projects is equally important as the total cost of the projects in setting reasonable rates." Staff's initial brief, p. 16. The Staff states that it "understands that capital expenditures can be reappropriated to more important projects during the year as maintenance arises. This is the reason why Staff did not choose to only update actual amounts for specific projects, but rather for all projects broad categories of capital expenditures where funding could be shifted." *Id*. The Staff also notes that DTE Electric did not file rebuttal regarding the Monroe Bottom Ash Conversion adjustment. *Id*., p. 17.

The Commission observes that DTE Electric's fleet is in transition and finds that it makes sense to utilize actual amounts where possible. DTE Electric states that the "variance between exhibit and actual project spends for these short few months is not a proper metric for measuring the performance of project execution, nor an adequate projection of final project results. Those referenced differences evidence nothing with regard to reasonableness and prudence of the projects." 6 Tr 1728. The Commission agrees with the latter statement and does not find the projects to be unreasonable or imprudent. Rather, the Commission finds that the evidence shows that the timing of the expenditures has changed. The Commission recognizes that projects are managed as a whole, but does not find that fact to be a convincing reason to burden ratepayers with aspirational spending goals when actual spending is available. DTE Electric posits that the reduction is being applied inconsistently, but the Commission notes that the Staff applied the proposed reduction based on actuals to the full routine and non-routine cost categories, with the exception of the reduction to the Monroe Bottom Ash Conversion, which the company did not rebut. The Commission adopts the Staff's proposed disallowances including the Monroe Bottom Ash Conversion disallowance which the company conceded in its reply brief. DTE Electric's reply brief, Attachment A, p. 2.

d. Commission Staff Adjustments Based on Classification/Development

The Staff proposes an additional adjustment to steam generation routine maintenance capital projects. The Association for the Advancement of Cost Engineering (AACE) International Cost Estimate Classification System specifies class cost levels which reflect the degree of risk associated with the cost estimate. The Staff notes that DTE Electric does not use this system but rather uses three internal levels consisting of PAT0 (a new project), PAT1 (engineering and procurement are undertaken), and PAT2 (construction is complete). 6 Tr 5180. Applying the AACE system to these levels, the Staff proposes a 15% reduction to projections for May-December 2024 ($10.65 million) and 20% for 2025 ($28.45 million). 6 Tr 5181; *see*, Exhibit A-12, Schedule B5.1, pp. 4-8. The Staff argues that the 2025 work is at an earlier stage akin to AACE Class 5 (most of the projects are at the PAT0 stage), and that the 2024 work equates to AACE Class 4. In support of this proposal, the Staff also notes that monthly actuals for the January to April 2024 timeframe are lower than the company's projections. 6 Tr 5180-5181; Staff's initial brief, pp. 19-21; Exhibits S-16.3 and S-16.4.

DTE Electric counters that the Staff is mistaken because these projects do not include any contingency cost estimates, meaning that they have already been stripped of risk. 6 Tr 1731. Thus, the company argues, the Staff proposes to de-risk projects that have already been de-risked and at a greater magnitude than the AACE scheme recommends. DTE Electric's initial brief, pp. 28-29. DTE Electric contends that the AACE guidelines themselves indicate that the "+/- value represents typical variation of actual costs from the cost estimate after application of contingency for the given scope[.]" 6 Tr 1731 (quoting Exhibit S-16.3, p. 3, Note A (emphasis removed)); *see*, DTE Electric's reply brief, p. 13. The company argues that the AACE guidance has been applied improperly since the projects do not include contingency funding.

The Staff responds that it does not question the necessity of the projects, but rather the timing of the spending and what is reasonable to put on ratepayers in the instant case. Staff's initial brief, pp. 20-21. The Staff states that it used the AACE ranges as a general guide and applied the lowest possible recommended adjustment for Class 4 and 5 cost estimates, which takes into consideration that contingency has already been removed. *Id*., p. 21; Exhibit S-16.3, p. 3. The Staff states that it was not privy to how the company arrived at its ranges or developed its cost estimates. *See*, 6 Tr 1595-1598. The Staff argues that underspending for six months shows a pattern, revealing that the projections "are either potentially overinflated to begin with, are not meeting projected schedules and spending milestones, or have cost reductions for other reasons compared to when the Company prepared it[s] forecast." Staff's initial brief, p. 21.

The Commission agrees with the Staff. In explaining its capital governance process, DTE Electric states that a "Project Approval Team (PAT) form is utilized to record CGB [Capital Governance Board] approvals." 6 Tr 1597. Beyond this, it is difficult to identify information in the evidentiary record detailing the PAT process other than the Staff's testimony at 6 Tr 5180 describing the meaning of the PAT levels, and what is provided in the Staff's Exhibit S-16.4, which indicates that the Staff got the assigned PAT levels from "project sheets." Exhibit S-16.4, pp. 1-2. The Commission is thus unclear what PAT0 and PAT1 indicate in terms of the expected certainty of the associated engineering, procurement, and construction costs. The categories seem to be both vague and broad, with PAT0 simply meaning that the project has entered the list of potential projects, and PAT1 encompassing everything between PAT0 and completion. The Commission encourages DTE Electric to add evidentiary detail to this process or to utilize the AACE (or something comparable), which provides significantly greater granularity. *See*, Exhibit S-16.3, pp. 2-9.

In the absence of more definite information on the cost certainty, the Commission finds that the Staff's proposed reductions are reasonable and should be approved. The Commission is not convinced that the fact that the company has already removed contingency funding is sufficient reason to reject the Staff's proposed reductions. As the Staff points out, the evidence showing the actual spending supports the argument that the estimates may be high. Additionally, in response to DTE Electric's contention that the AACE guidance does not apply to amounts that contain no contingency spending component, the Commission observes that the AACE's definition of the expected accuracy range states that "[t]he state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope." Exhibit S-16.3, p. 2, n. [a]. It goes on to state that the expected accuracy range "results in a 90% confidence that the actual cost will fall within the bounds of the low and high ranges" and that the ranges may be exceeded in unusual circumstances. *Id*., p. 3. The accuracy range for Class 5 is from a low of -20% to -50% to a high of +30% to +100%. *Id*., p. 2. Against this background, the Commission finds the Staff's proposal to be reasonable even in the absence of contingency funding. The evidence is simply not sufficient to show that the full amounts that are proposed by the company will be spent during the designated time periods.

Moreover, the Staff's recommended 15% and 20% reductions in the instant case are for class levels that are more uncertain than the levels for which they have been recommended in past cases (and in the instant case in other cost categories). The Commission observes that it has made similar findings in the July 2, 2024 order in Case No. U-21461, pp. 24-25 (a 15% reduction to a Class 2 power generation project); the November 18 order, pp. 191-192 (a 20% reduction to Class 3 IT projects); and the December 1 order, p. 147 (a 20% reduction to Class 3 IT projects). As the Commission has stated, its "determination of reasonableness and prudency (and its obligation to protect ratepayers) involves more than the simple hope that the over- and under-projections balance one another out. MCL 460.6; MCL 460.6a." November 18 order, p. 192. And, in DTE Electric's most recent rate case, "[t]he Commission also finds persuasive the Staff's rationale for using the AACE Class 3 Estimate to derive its 20% disallowance here, and as acknowledged by the Staff, '[i]f the Company spends more than 80% of the projected cost, it can include the updated information in the next electric rate case to be reviewed for reasonableness and prudency.' *Id*., p. 60." December 1 order, p. 147 (quoting the Staff's initial brief). The same is true in the instant case.

e. Blackstart Projects

DTE Electric projects a total of $34.4 million for several blackstart projects (including the peaker unit 2 starting system project and the unit major overhaul project) in the bridge period and test year. Exhibit A-12, Schedule B5.1. A blackstart unit refers to a generation unit that is capable of starting on its own without support from the grid, in the event of a major grid event such as the 2003 blackout. 6 Tr 4753. Blackstart units constitute part of a reliable system restoration plan (SRP) that is required by the North American Electric Reliability Corporation (NERC). 6 Tr 4754-4755.

ABATE proposes a full disallowance of $34.4 million for 2023-2025 associated with the blackstart projects. 6 Tr 3348-3354; Exhibit AB-2; ABATE's initial brief, pp. 10-12. ABATE argues that the project management and planning documents (PMPDs) were redacted and thus the parties could not properly review these projects because much of the information about the scope and timelines is not available. *Id*. ABATE notes that it is not possible to determine what revisions have been made to the projects from the exhibits, and the testimony also provides limited information. ABATE contends that DTE Electric cannot demonstrate reasonableness on the basis of so little information.

DTE Electric counters that the redactions reflect the fact that the PMPDs contain CEII. The company argues that the Commission rejected ABATE's argument in the December 1 order, p. 43, and it should be rejected again. 6 Tr 1735; DTE Electric's initial brief, p. 30; DTE Electric's reply brief, pp. 13-14.

Additionally, based again on the variance between projections and actuals, the Staff proposes an update to the projected costs of certain non-routine projects to disallow $1.37 million for 2023 and $1.23 million for 2024 (reductions to multiple projects of a combined $611,000, $886,000, and $1.07 million). 6 Tr 5050-5056; Staff's initial brief, p. 22-29; Exhibit S-10.2. The Staff's disallowances are based on actual spending for 2023, and the disallowances for 2024 are based on the discrepancy between the amounts forecasted in Case No. U-21297 and actual capital incurred (a 14% difference). Staff's initial brief, p. 27. The Staff notes that in the November 18 order, pp. 43-48, the Commission disallowed all bridge and test period spending in this cost category, and in the December 1 order, pp. 42-43, it adopted partial disallowances based on the Staff's updates reflecting actual spending. The Staff argues that the company has shown a consistent pattern of overestimating costs for blackstart projects. 6 Tr 5054; Staff's initial brief, p. 24. The

Staff notes that it has not proposed reductions across the board, but rather its evidence "zeroes in on a specific line item rather than looking at all projects . . . [N]on-routine projects are by their very nature those that do not have a good basis to be used to estimate from." *Id*., p. 26. The Staff adds, "[c]ouple that with the fact that the Company chooses to and does not have to use a projected test year, the benefit of doing so should reasonably come with a higher burden of proof for the Company to ensure it is accurately forecasting project expenses." *Id*. The Staff argues that its adjustment methodology for 2024 has been approved by the Commission in at least four prior rate cases. *Id*., pp. 27-28.

DTE Electric counters the Staff's update argument on the same grounds as stated above and claims that the Staff is also inconsistent in its application of this method. The company states that "future spending is likely to be higher than the original forecast due to spending milestones shifting to the future." DTE Electric's initial brief, p. 30; 6 Tr 1737; DTE Electric's reply brief, p. 14.

ITC supports recovery of the blackstart amounts. 6 Tr 4753-4759; ITC's initial brief, pp. 16-18; ITC's reply brief, pp. 4-5. ITC contends that blackstart resources are being lost due to the transformation of the generation fleet and that these investments will ensure that Michigan is prepared for a major event. ITC argues that the redacted documents contain CEII and there is a limit to how much DTE Electric can share, but that significant detail is still provided. ITC argues that there has been no change in circumstances since the Commission rejected ABATE's argument in the December 1 order.

In its reply, ABATE argues that the parties could not sufficiently review these projects, particularly with respect to the scope and the timeline. ABATE's reply brief, pp. 6-7.

The Commission recognizes that these blackstart resources are critical to the safety and resilience of the grid at times of major outage events. As it found in the December 1 order, pp. 43-44, the Commission is not persuaded to approve the large disallowances proposed by ABATE simply on the basis of the fact that the PMPDs contain redactions, as these documents contain highly confidential CEII. The Commission finds that DTE Electric has placed sufficient detail in the record to justify recovery. 6 Tr 1627-1630, 1701-1705. However, the Commission also finds that the Staff's proposed disallowances, which simply update the revenue request to reflect actual spending, are appropriate and should be approved. Thus, the Commission adopts reductions of $1.37 million for 2023 and $1.23 million for 2024. 6 Tr 5053-5054.

f. Trenton Channel Storage Project

The Staff proposes a reduction to the projected spend for the Trenton Channel BESS project, related to the work that has not yet been contracted, of 10% for the bridge period ($1.6 million) and 20% for the test year ($8.3 million). 6 Tr 5061-5062; Exhibit S-10.6; Staff's initial brief, pp. 33-34; Exhibit A-12, Schedule B5.1, p. 2. The Staff explains that this is construction work in progress (CWIP) with an allowance for funds used during construction (AFUDC) offset, and argues that the proposed spending is uncertain because there are no established contracts associated with these amounts. The Staff states that its proposed reduction is made to all cost categories that do not have an executed contract, arguing that a contract that has not been executed "is no more defined than non-contract[ed] work." Staff's initial brief, p. 34.

DTE Electric counters that the Staff provided no explanation for how it selected these percentages and the calculations appear to be inconsistent. 6 Tr 1738; DTE Electric's initial brief, p. 31; DTE Electric's reply brief, p. 14.

The Commission finds no inconsistency and adopts the Staff's proposed bridge and test year disallowances for projects that either have no contract or have a contract that has not been executed. Based on data provided by the company, the Staff shows (in Exhibits S-10.5 and S-10.6) what work will be performed under contract. 6 Tr 5061. There is $59.36 million in projected work that has no associated contract. 6 Tr 5061. The Staff proposes a flat percentage reduction to the bridge and test periods and the Commission agrees that this adjustment makes sense in light of the uncertainty of the work and the cost estimates.

g. River Rouge Decommissioning Project

DTE Electric projects costs of $33.96 million in the bridge period for this project; of those costs, $12.8 million is projected for 2024. Exhibit A-12, Schedule B5.1. ABATE proposes a disallowance of $4.4 million for 2024 for the River Rouge decommissioning project based on the difference between the company's projection and the amount indicated on the company's Capital Appropriation Request Form (CARF), which shows that the company provided an appropriations request reflecting spending of $8.4 million in 2024 ($4.4 million less than the projection). 6 Tr 3350-3351; Exhibit AB-2; ABATE's initial brief, p. 10. The CARF is used for projects greater than $10 million. 6 Tr 1597-1598.

DTE Electric counters that the CARF actually shows that this project has total funding of $94.9 million which includes $48.3 million for the test year. DTE Electric's initial brief, p. 32. Thus, the company argues, "there is more than enough funding authorized and anticipated for this long-term project to cover the $4.4 million paperwork difference identified by ABATE." *Id*.; 6 Tr 1739-1740; DTE Electric's reply brief, p. 14.

ABATE replies that the CARF shows spending of $8.4 million in 2024 and any approval should be limited to this amount, thus disallowing $4.4 million for 2024. ABATE's reply brief, p. 6.

The Commission adopts ABATE's proposed disallowance. DTE Electric asks the Commission to find that there is "sufficient approved funding to cover the 2024 difference in paperwork" identified by ABATE. 6 Tr 1740. In that testimony, the company addresses the projected spending for the test year but does not mention 2024, and refers to the "minor paperwork difference." 6 Tr 1739. The Commission finds that $4.4 million is not irrelevant and adopts ABATE's proposed $4.4 million reduction in conformance with the company's appropriation for this work.

h. Slocum Battery Pilot

The Slocum battery pilot involves replacement of diesel-fueled generating units with a BESS which will be available for dispatch during peak hours, for which the Commission approved partial disallowances in the November 18 order, p. 51, and the December 1 order, p. 245. 6 Tr 1630-1631. The Staff proposes a disallowance of $2.18 million in the bridge period on grounds that this amount represents increases to project overheads since the last rate case that were not supported by the company on the record. 6 Tr 5055-5058; Staff's initial brief, pp. 31-33; Exhibit S-10.3.

DTE Electric counters that it fully explained that the increases resulted from increases to material and labor costs on which indirect overheads are calculated, and that the increase is proportional to the overhead amount that the company presented in Case No. U-21297. 6 Tr 1741; DTE Electric's initial brief, p. 33; DTE Electric's reply brief, p. 14.

The Staff responds that this explanation is still inconsistent with the updated costs. The Staff explains that allocations of overheads are done monthly and overheads are based on actual direct costs such as labor, material, and contracts. The Staff finds DTE Electric's explanation of the increased overheads to be nonspecific and not credible. The Staff states that:

> [b]etween this filing and MPSC Case No. U-21297, project materials were forecasted to increase by $5M, or 25%, while project labor increased by $2M, or 37%, for a combined increase for the two categories of $7M, or 34%. (6 TR 5057-5058.) The forecasted $2.2M increase to project overhead [for this pilot], however, represents an almost 45% increase to that category.

Staff's initial brief, p. 32. The Staff notes that overhead costs are about 1.3% higher in the instant case than they were in Case No. U-21297 for this particular cost category, and contends that this increase is unsupported. *Id*., p. 33.

The Commission adopts the Staff's proposed reduction. The Staff notes that, based on data provided by the company, material and labor costs have increased since the last rate case by about 34%, but project overhead costs have increased by 45%. DTE Electric does not rebut the Staff's calculations or argue that the Staff relied on the wrong data, but rather argues that the overhead costs have remained consistent as a percentage of total project costs. 6 Tr 1742. However, the Staff showed that the percentage increase to overhead costs does not align with the percentage increases to projected material and labor costs as originally claimed by DTE Electric, and the Commission finds that the disallowance based on the discrepancy should be approved.

i. Trenton Channel Seawall Project

DTE Electric projects costs of $1.43 million in the bridge period and $9.5 million in the test year for this project. Exhibit A-12, Schedule B5.1. DTE Electric argues that the project is necessary because the existing seawall at the Trenton Channel Power Plant is at the end of its life. The company argues that it is required to ensure the stability of the land at the Detroit River riverfront, and that it is also required by the City of Trenton to develop a pedestrian green path. 6 Tr 1743-1744; Exhibit A-12, Schedule B5.1; DTE Electric's initial brief, p. 33.

ABATE proposes a disallowance of the full $10.9 million, on grounds that the evidence does not support the level of investment shown in the company's exhibit. 6 Tr 3348-3350; Exhibit AB-2; ABATE's initial brief, p. 10. ABATE notes that these costs have not yet been the subject of an actual internal appropriations request for the full amount. *See*, 6 Tr 1744.

DTE Electric counters that Exhibit AB-2, p. 1, shows that $1.1 million has been appropriated for the project and the company has already spent half of that, and the project will be completed in 2025. 6 Tr 1744; DTE Electric's initial brief, p. 33; DTE Electric's reply brief, p. 14.

ABATE replies that this appropriations request does not support the level of expenditure that is being sought by the company. ABATE's reply brief, p. 5.

As DTE Electric notes, it has spent $500,000 on this project to date and has appropriated $1.1 million. 6 Tr 1744; DTE Electric's initial brief, p. 33; DTE Electric's reply brief, p. 14. As such, the Commission adopts ABATE's proposed disallowance, with the exception of the $1.1 million appropriated for the project. This work is associated with the demolition of the Trenton Channel power plant and the construction of the new BESS. While recognizing that the work is likely to be carried out at some point, the Commission finds that the evidence provided by the company in support of the cost estimates is not adequate to allow for approval of the proposed amounts in the instant case. The Commission reminds the company that, "even for otherwise worthwhile investments, whether a proposed investment is likely to be made during the time period in question goes to the heart of whether that investment is truly 'reasonable, prudent, and worthy of recovery.'" November 7, 2024 order in Case No. U-21291 (November 7 order), p. 24 (citations omitted). In regards to the Trenton Channel Seawall Project, DTE Electric indicates that it has appropriated $1.1 million for the whole project thus far. Absent additional support for the remaining $9.8 million projected to be spent on the project, including that the full amount will be spent in the test year, it is unreasonable to include this amount in customer rates on a prospective basis. As such, the Commission adopts a disallowance for this project of $9.8 million and finds that the company may seek additional supported amounts beyond the $1.1 million approved for this project in a future rate case when these projects have received additional internal review and approval.

j. Distribution-Connected Storage

GLREA asks the Commission to direct DTE Electric to "consider the benefits of installing future BESS capacity in smaller, distribution-connected units, and that any future BESS proposal should include an analysis of opportunities for distribution-connected BESS, and why that option was, or was not selected by the Company." 6 Tr 4857-4858; GLREA's initial brief, pp. 27-29. GLREA contends that the company has unique knowledge about which of its substations are under stress and about the estimated cost of addressing that stress, arguing that a BESS request for proposal (RFP) does not provide that information and this discourages RFP respondents from proposing substation-located systems. *Id*., p. 28; GLREA's reply brief, pp. 8-9. GLREA argues that "third-party developers could install transmission-connected BESSs" rather than utility capital being spent on these efforts. *Id*., p. 9.

DTE Electric counters that, under its currently-approved integrated resource plan (IRP), the company is required to comply with the Commission's Competitive Procurement Guidelines for Rate-Regulated Electric Utilities approved in the July 26, 2023 order in Case No. U-21193, and that it is doing so. DTE Electric argues that it is already required to apply an open and transparent evaluation when considering distribution-connected resources and it is providing the required information. DTE Electric's initial brief, p. 34. Noting GLREA's RFP arguments, DTE Electric contends that "GLREA appears to suggest that the Company should redesign RFPs to include information on stressed substations. The brief's new proposal is unfounded and comes too late for evaluation. Therefore, no Commission action is necessary or appropriate, and GLREA's proposal(s) should be disregarded." DTE Electric's reply brief, p. 15.

The Commission encourages DTE Electric to consider the deployment of BESS capacity in smaller, distribution-connected units and substations, but finds that compliance with the Competitive Procurement Guidelines is sufficient to address GLREA's concern at this time.

k. 2023 Underspend

The Attorney General notes that 2023 capital expenditures were underspent by $25.2 million. Attorney General's initial brief, pp. 28-29; 6 Tr 3617-3618. DTE Electric agreed to this adjustment on rebuttal. 6 Tr 3086-3087. The Attorney General also notes that the actual 2023 capital expenditures for power generation reported by DTE Electric are $3.95 million lower than the forecast provided by the company for 2023 and she proposes that this difference should be removed from rate base. 6 Tr 3620; Attorney General's initial brief, p. 31. The company provided no rebuttal to this specific proposal and did not address it in its initial brief. The Commission notes that DTE Electric reflects the 2023 underspend of $25.2 million, the $3.95 million underspend, and the accumulated depreciation of $1.98 million, in Attachment A, p. 2, of its reply brief. The Commission adopts these adjustments to the 2023 capital expenditure forecast.

2. Midwest Energy Resources Company and Fuel Supply

DTE Electric proposes MERC and Fuel Supply capital spending of $2.2 million for 2022, $2.9 million for the bridge period, and $1.2 million for the test year, in order to maintain safe and reliable environmentally-compliant operations for MERC's transshipment capabilities and Fuel

Supply's railcar availability. 6 Tr 1752-1763; Exhibit A-12, Schedule B5.2; DTE Electric's initial brief, p. 37; DTE Electric's reply brief, p. 16. In response to the Commission's direction in the December 1 order, p. 50, to provide an evaluation of the MERC investments, DTE Electric explains the critical nature of transshipment of coal. 6 Tr 1754-1755. DTE Electric states that it plans to cease MERC transshipments at the end of 2026, which coincides with the end of coal deliveries to Belle River, and it plans to retire the railcar fleet in 2032 consistent with the retirement of the last two units at Monroe. Thus, the company contends that its spending requests are substantially reduced. The Staff proposes a reduction of a net $103,000 based on updated actual amounts known through April 2024. 6 Tr 5181; Exhibit S-16.5; Staff's initial brief, p. 35. DTE Electric did not file rebuttal on this proposal or mention it in its initial or reply briefs. The Commission adopts the Staff's proposed adjustment.

3. Nuclear Generation – Fermi 2

The Fermi 2 Nuclear Power Plant (Fermi 2) is licensed by the Nuclear Regulatory Commission to operate through 2045. DTE Electric reports or proposes capital spending of $257.8 million for 2022, $451.5 million for the bridge period, and $215.9 million for the test year. 6 Tr 1805-1808; Exhibit A-12, Schedule B5.3, pp. 1 and 4; Exhibit A-20, Schedule J2; DTE Electric's initial brief, p. 39. Testimony at 6 Tr 1814-1849 describes certain routine and small projects as well as non-routine and large projects necessary to maintain safe and reliable operations per DTE Electric, and indicates that none of the amounts include contingency spending. For nuclear generation, DTE Electric reports that "2022 capital expenditures totaled approximately $254.5 million, and the projected capital expenditures are approximately $339.5 million for the bridge period ending December 31, 2024, and $80.9 million for the projected test year." DTE Electric's initial brief, p. 40 (footnote omitted) (citing 6 Tr 1883, 1895).

a. Commission Staff Adjustments Associated with Actual Amounts and Risk Class

Again based on actual expenditures and the risk of inaccurate projections, the Staff proposes $45.5 million in disallowances related to Fermi 2, consisting of: (1) $15.7 million for the five-month period ending April 30, 2024 ($7.87 million for routine and small projects; $7.87 million for non-routine and large projects) based on actuals; (2) $13.6 million for the seven-month period ending December 31, 2024 ($3.73 million for routine and small projects; $9.89 million for non-routine and large projects) based on Class 4 cost estimates; and (3) $16.2 million for the test year ($8.49 million for routine and small projects; $7.68 million for non-routine and large projects) based on Class 5 cost estimates. Exhibit A-12, Schedule B5.3, pp. 2-4; Exhibit S-16.6; 6 Tr 5182-5185; Staff's initial brief, pp. 35-41. Like the adjustments discussed above with respect to steam generation, the Staff argues that these projections should be updated to reflect actual amounts provided in discovery for the five-month period ended April 30, 2024; and should be reduced by 15% for the remainder of the bridge period and by 20% for the test year based on the relative accuracy of the projections as reflected by their stage of development, applying AACE Class 4 and Class 5 cost estimates. *Id*.

DTE Electric counters that this is another proposed disallowance "based on project timing variances rather than any performance variance" and a timing variance simply means that the "work was completed or will be completed for the projected expenditure, but the projected expenditure's timing is sooner or later than originally forecast." DTE Electric's initial brief, p. 41 and p. 41, n. 34. DTE Electric contends that this is an unreasonable basis for a reduction to proposed spending because it is based only on short-term looks at monthly spending. DTE Electric again argues that capital projects must be managed as a whole, particularly where the timing of refueling outages must be considered. 6 Tr 1886-1888. DTE Electric contends that this is particularly relevant for the Staff's first proposed disallowance related to actual amounts spent in November 2023 to April 2024. The company argues that variances in timing do not represent permanent underspends and spending must be expected to peak during refueling outages. DTE Electric states that Exhibit A-47, Schedule LL1, updates the five-month capital expenditures shown in the Staff's Exhibit S-16.6 to include May, June, and July 2024 expenditures. The company argues that this demonstrates that the total capital expenditures for the eight-month period were close to projected, showing actual expenditures of $160.4 million and planned expenditures of $162.8 million. 6 Tr 1888-1889.

Again, DTE Electric also argues that risk has already been removed from these projections because no contingency costs have been included, making the Staff's proposal incorrect. DTE Electric's initial brief, p. 43; DTE Electric's reply brief, pp. 16-17. The company contends that the AACE guidelines call for application of the percentage reductions to estimates that already have contingency built in. *See*, Exhibit S-16.3, p. 3. DTE Electric maintains that the evidence shows actual nuclear expenditures through July 2024 and those should not be ignored. DTE Electric's reply brief, p. 17.

The Staff responds that it "can accept the Company's explanation on nuclear spending during a refueling outage being variable. However, Staff did not have additional monthly information available before internal deadlines and would argue that the monthly amounts Staff updated are still representative of the Company's actual spending." Staff's initial brief, p. 37. The Staff also contends that, in response to discovery, DTE Electric "did not provide any indication of what stage of planning each project is in or how complete each nuclear project is; therefore, Staff adjusted all nuclear capital projects." *Id.*, p. 38. Again, the Staff indicates that it used the AACE adjustment ranges as a general guide in the absence of information from the company on how it developed its own ranges and estimates.

The bases for the Staff's proposed reductions are identical to the bases articulated by the Staff with respect to steam generation, discussed above, and the Commission finds that the same conclusions are reasonable. The Commission adopts the Staff's proposed reductions based on actual spending and on the risk associated with uncertain cost estimates for the reasons described above in Sections V.B.1.c. and V.B.1.d. of this order.

b. The Michigan Department of Attorney General's Adjustments

The Attorney General proposed five adjustments totaling $175.4 million in disallowances for nuclear generation. The adjustments are addressed below.

i. Service Beyond the Test Year

The Attorney General proposes a reduction of $58 million for 2024 and $25.87 million for test year nuclear capital expenditures, which includes amounts associated with projects with an in-service date of 2026. 6 Tr 3628-3629; Attorney General's initial brief, p. 35. In the Attorney General's reply brief, p. 13, she again states that $25.87 million should be excluded from the test year for projects that will be put into service beyond the test year. The Attorney General states that she agrees with the company that, if her adjustment is made, then there should be a corresponding reduction to AFUDC of $12.39 million. Attorney General's initial brief, p. 35.

DTE Electric counters that the Attorney General misunderstands accounting principles and the company's exhibits, because such projects have no impact on the company's revenue deficiency. 6 Tr 1567-1568, 1896-1902; DTE Electric's initial brief, p. 44; DTE Electric's reply brief, p. 18. DTE Electric explains that the in-service date does not affect the revenue requirement because

CWIP is offset by an AFUDC allowance. The company adds that it provided the in-service date projections to Exhibit A-12, Schedule B5.2, to offer transparency.

The Commission observes that ABATE made this same in-service timing argument in Case No. U-21297, and ABATE makes the same argument again in the instant case with regard to strategic capital (which is discussed below). The Commission addressed this issue in the December 1 order as follows:

> The Commission is not persuaded to adopt ABATE's proposed adjustments. The Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base. Many worthwhile and necessary projects have to be implemented over time spans that well exceed the end of the test year and the decision made in the May 10 order addresses the associated accounting issue. That said, the Commission wholeheartedly agrees with the ALJ's (repeated) observation that the projected total cost must be provided for all such projects. The Commission recognizes that it is a projection, but in order to make fully informed decisions, the projected total cost of a project must be known. Nevertheless, the Commission does not find that all such projects must be excluded from rate base, despite the fact that the exclusion has no impact on the revenue requirement. The Commission finds it preferable to examine the evidentiary basis for including or excluding each program at the requested funding level (which, the Commission observes, the ALJ often examined as well).

December 1 order, pp. 84-85. Nothing on the record in the instant case persuades the Commission to deviate from this recent holding. The Commission rejects the Attorney General's proposed adjustment to nuclear project costs based on the in-service date. The Commission will continue to examine the evidentiary basis for each program or project.

ii. Security System Computer and Plant Radio System Projects

The Attorney General proposes a $41.1 million reduction associated with the security system computer and plant radio system projects. 6 Tr 3621-3625; Attorney General's initial brief, pp. 32-33. The Attorney General argues that the security system computer project should be allowed no more than the initial project cost of $9.9 million plus 10%, which comes to $10.94 million, and the plant radio system project should be funded in the same manner (original cost was $6 million), which amounts to $6.6 million. 6 Tr 3621-3625. Regarding the security system computer project, the Attorney General notes that this project has ballooned from a total of about $9.9 million to $39 million, but that the documentation provided by DTE Electric does not fully explain the cost overruns. 6 Tr 3621-3623. Based on imprudent cost management, she argues that the Commission should approve the original cost plus 10% ($10.94 million) for 2024, and disallow $9.19 million from 2024 and fully disallow the remainder, that is, $19 million from 2023 and 2022. 6 Tr 3623; Attorney General's initial brief, p. 32.

Regarding the plant radio system project, she makes the same arguments, based on the fact that the original projection was for a total of $6 million but it has risen to $19.43 million. Based on a similar claimed lack of information as to why the costs have risen so quickly, the Attorney General labels this imprudent cost management and seeks a reduction of $1.5 million for 2024 and $11.3 million for 2023 and 2022. 6 Tr 3625; Attorney General's initial brief, p. 33. The projected original cost was $6 million, so she advocates approval of that amount plus 10%, or $6.6 million. She argues that these costs are not contingency but rather overruns which reflect imprudent practices. Attorney General's reply brief, p. 13.

DTE Electric counters that the Attorney General misunderstands the company's internal capital appropriations request forms where only partial approvals are sought. DTE Electric's initial brief, p. 45. The company states that it has presented both of the projects to the Commission with higher numbers in the past, in Case Nos. U-20836 and U-21297, and argues that it has provided testimony explaining the changes to the original budgets. 6 Tr 1897-1900. DTE Electric explains that the $9.9 million which the Attorney General refers to as the original budget was actually only an "initial partial appropriation approval to initiate the project." 6 Tr 1897 (emphasis in original). The company maintains that this initial amount was only sufficient to start the project and allow for the development of a full budget, stating that this "is a reasonable practice when the necessity and reasonableness of the intended work is not in doubt, as is often the case in Nuclear Generation." 6 Tr 1897. DTE Electric argues that it is standard practice to request authorization of a full budget at a later date or in tranches. 6 Tr 1898.

The company makes the same argument with respect to the plant radio system project, explaining that the $6.0 million was only the initial partial appropriation, which was internally approved in October of 2022. 6 Tr 1898. DTE Electric notes that in Case No. U-20836 the company presented projected costs of $24.8 million for the security system computer project and $8.1 million for the plant radio system project, and in Case No. U-21297 it presented projected costs of $23.9 million and $11.9 million, respectively. 6 Tr 1899. DTE Electric maintains that these projections still exclude contingency and are "highly certain" to be incurred. DTE Electric's initial brief, p. 46; DTE Electric's reply brief, p. 17. The company contends that these are not simply cost overruns.

The Commission finds that DTE Electric adequately supported these projects and rejects the Attorney General's proposed reductions. These two projects are multi-year routine and small projects that are related to plant safety at Fermi 2, "with predominantly online implementation." 6 Tr 1817. DTE Electric reports spending of $7.1 million in 2022, projects spending of $26.8 million in the bridge period, and nothing in the test year for the security system computer project, which addresses the obsolescence of the existing security system computer. 6 Tr 1817. The need for the project and its goals, along with regulatory requirements for security, are described at 6 Tr 1817-1821, and the company states that the work was competitively sourced. Reported/projected costs for the plant radio system are $4.2 million for 2022, $7.5 million for the bridge period, and nothing for the test year, which addresses the replacement of the Fermi 2 plant radio system. 6 Tr 1821. The need for the project and its goals, along with regulatory requirements for communications systems, are described at 6 Tr 1821-1824. The Commission notes that both of these cost categories were disallowed in the November 18 order, pp. 52-55, and 57-59. However, the Commission finds that the record in the instant case provides a sufficient explanation for the increases in both budgets. For the security system computer project, the increase arises from nine security-related items with changed costs, and for the plant radio system project the increase is related to the wires powering the uninterruptible power supplies. 6 Tr 1899-1901. The Commission approves the company's projected costs.

iii. Natural Draft Cooling Towers and Other Projects

The Attorney General apparently proposes a $24 million reduction for the natural draft cooling towers, document management system enhancements, and remote monitoring projects. 6 Tr 3628; Exhibit AG-12, p. 2. In testimony, the Attorney General contends that the company failed to identify project phases and timelines. However, the Attorney General did not mention any of these projects in either her initial or reply brief. *See*, Attorney General's initial brief, pp. 31-35; Attorney General's reply brief, pp. 12-14.

DTE Electric counters that it does not use the approval process that the Attorney General envisions (describing it as the phase-gate approval process) for nuclear generation because it would result in "decision-making paralysis[,]" and further because these nuclear generation activities are not the same as typical building construction activities. DTE Electric's initial brief, p. 47 (quoting 6 Tr 1904); 6 Tr 1903-1906; DTE Electric's reply brief, pp. 17-18. DTE Electric contends that these are capital maintenance activities with few engineering requirements and are not suited to the type of approval process that the Attorney General relies on.

The Attorney General incorporates all of her witness's (Mr. Coppola's) testimony by reference in her initial brief, p. 34, n. 82, but does not argue this issue in her briefs, thus it appears to have been abandoned. The Attorney General asked in discovery for the project's phases, a timeline, and the current project phase. The Commission finds DTE Electric's discovery response located at Exhibit AG-12, p. 2, to be wholly inadequate. However, DTE Electric provided some additional evidence on rebuttal. 6 Tr 1902-1906. It is not clear to the Commission, on this record, why nuclear projects must be excused from having phases or timelines (which clearly they must have). However, as her introductory argument was not further pursued, the Commission rejects the Attorney General's proposed reduction to these three capital projects based on DTE Electric's rebuttal, without opining on the company's nuclear project management process as a whole. The Commission expects that, in future, DTE Electric will respond to discovery that simply asks for a project's phases, a timeline, and identification of the current phase of the project (unless, of course, the question is subject to objection). In Exhibit AG-12, p. 2, the company indicates that it "cannot provide project status in the requested manner." However, the Attorney General did not designate any particular manner, and, if the examples given by the Attorney General were in-apt, the company could still have provided the information in whatever manner the company compiles the information. The information was requested only for projects in excess of $3 million. The Commission believes that it is likely that any $3 million project has some kind of project schedule or timeline that goes beyond simply the in-service date.

iv. Sanitary System Replacement Project

This project addresses aging and undersized piping in the Fermi 2 sanitary wastewater system which the company intends to replace. 6 Tr 1847-1848. DTE Electric projects no spending in the historical or bridge periods, and $6.5 million in the test year. 6 Tr 1847. The Attorney General proposes a full disallowance of $6.5 million for the test year for this sanitary system replacement project because the project lacks a plan, timeline, and completion date. 6 Tr 3629; Attorney General's initial brief, p. 34.

DTE Electric counters that the project is intended to be completed in 2025, but some additional expenditures may extend beyond the test year. 6 Tr 1847-1848; DTE Electric's initial brief, p. 48. DTE Electric states that it "does not status projects as a particular phase or in the manner requested." *Id*. The company adds that the project will not start until 2025, and argues that this essentially means that the company cannot respond to the Attorney General's discovery request for information such as concept scoping, engineering design, whether it is out for bids, and other basic information. 6 Tr 1907-1908; Exhibit AG-12, p. 2.

The Attorney General argues that the company's rebuttal simply includes excuses for not providing the requested basic information. Attorney General's initial brief, p. 35.

The Commission agrees with the Attorney General. Again, the Commission is not persuaded that nuclear-related projects must necessarily lack timelines and basic planning information, even if such planning uses a process that is different from the planning process used for non-nuclear cost categories. The company's testimony describes the need that has been identified and states that the work will probably begin and end in 2025, but also explains that "[a]dditional expenditures to replace or reroute additional portions of the sanitary system may be required – though not known at this time[.]" 6 Tr 1906. The Commission again notes the inadequate response to discovery in Exhibit AG-12, p. 2. The Commission finds that DTE Electric did not adequately support this proposed expenditure and adopts the Attorney General's reduction. This project appears to be premature. The Commission observes that, if this project is actually undertaken in the test year, DTE Electric may provide sufficient support and seek recovery of reasonable and prudent costs in a future rate case.

v. Nuclear Fuel Capital Expenditures

The Attorney General proposes a $20 million reduction to projected nuclear fuel costs for the test year because the projections do not align with historical amounts, particularly with 2023. 6 Tr 3623-3627; Exhibit AG-11; Attorney General's initial brief, pp. 33-34. The Attorney General argues that DTE Electric has a tendency to overestimate its nuclear fuel costs, and argues that the company has historically asked for more than it spent. 6 Tr 3627; Exhibit AG-50, p. 21. The Attorney General advocates using an average of the 2021 ($120 million) and 2023 ($110 million) amounts, which results in the $20 million reduction to the company's requested $135 million for the test year.

DTE Electric counters that the Attorney General misunderstood its discovery response or its projections, because the difference in the number of fuel assemblies results in differences in cost and 11% more assemblies are indicated for 2025 compared to 2023. 6 Tr 1908; DTE Electric's initial brief, pp. 48-49. DTE Electric contends that Exhibit AG-11, p. 3, shows these differences and explains that nuclear fuel costs are related to the nuclear fuel cycle components and are consistent with the company's 2024 PSCR plan approved in the July 23, 2024 order in Case No. U-21425. 6 Tr 1908-1909. The company argues that the Commission can have confidence in its projections based on historical accuracy. 6 Tr 3626, 1912-1914. The company also urges the Commission not to rely on a simplistic average of costs in 2021 and 2023 because each refueling outage involves the replacement of a different number of fuel assemblies. DTE Electric's reply brief, pp. 18-19. The company argues that the Attorney General ignores the increase to the volume of fuel.

The Commission notes that the fuel cycle was 18 months (and moved to 24 months in 2022) and thus does not align easily with annual figures. *See*, 6 Tr 1811. The Commission also finds that DTE Electric showed that its historical cost estimates have been reasonably accurate, with the net variance for the three years of 2019, 2020, and 2021 being less than 0.5%, and a slightly higher percentage of variance (1% and 4%) for other years from 2018 onward. 6 Tr 1911-1912. The company also showed that the number of fuel assemblies differs from year to year. The Commission finds that the Attorney General did not demonstrate the overestimation that she posits, and approves the company's projected test year nuclear fuel expenditures.

4. Distribution Operations

a. Overview

DTE Electric reports or projects distribution operations (DO) capital expenditures of $1.5 billion for 2022, $3.14 billion for the bridge period, and $1.63 billion for the test year. 3 Tr 317; Exhibit A-12, Schedule B5.4, p. 1. DTE Electric states that it agreed with the Attorney General's proposed removal of $25.2 million from 2023 capital expenditures based on actuals being less than the forecasted amounts for that year. 6 Tr 3086-3087; DTE Electric's initial brief, p. 51, n. 38; Staff's initial brief, p. 42. DTE Electric describes its equipment as "relatively aged, with 8 of the 18 asset classes having an average age at or near the equipment life expectancy (Kryscynski, 3T 306-309)." DTE Electric's initial brief, p. 52. The company states that its DO investments will provide a foundation for grid modernization and greater resiliency. Regarding reliability, DTE Electric states:

> AG-MN witnesses Alvarez (6T 3931) and Stephens (6T 3992), and Ann Arbor witness Stults (6T 4248) suggested that all-weather system-wide reliability is not showing an improving trend, despite recent increases to investment. The reason is that, at the macro level, volatile weather conditions greatly influence system-wide all-weather System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Many customers are seeing

> reliability improvements from investments, but the Company continues to face three primary challenges going forward: (1) an increase in the number of high wind speed days, which adds additional stress to the already-aged fleet of equipment and provides more opportunities for failures; (2) the system continues to get older, which requires continuing investments to decrease the rate at which the Company's assets are aging; and (3) the Company is early in its journey to stabilize and rebuild the grid, which requires increased and sustained investments to improve and then maintain reliability (Kryscynski, 3T 313-17, 399-400).

Id. DTE Electric acknowledges the need to address harsher weather conditions, advancing electrification, and greater integration of DERs. 3 Tr 317. DTE Electric explains that DO capital spending is divided into base capital and strategic capital, and base capital is further divided into emergent replacements (reactive expenditures to address immediate safety or operational concerns) and customer connections and relocations (planned expenditures to integrate customers). Further, emergent replacements have three major categories: Storm, Non-storm, and Substation reactive. DTE Electric's initial brief, pp. 52-53.

In general remarks, the Attorney General asserts that DTE Electric's reliability metrics are "some of the poorest in the nation and . . . she advocates for increased accountability metrics that tie revenue increase requests to actual, quantifiable improvements." Attorney General's reply brief, p. 15. The Attorney General rejects as unconvincing the company's explanation regarding volatile weather. *Id*.

MNSC also argues that "DTE has not provided evidence correlating outages with wind speeds. DTE has not provided evidence correlating outages with old equipment. DTE has been increasing its investments in distribution plant for years without while [sic] reliability worsens[.]" MNSC's reply brief, p. 6 (citing 6 Tr 3931).

Specific disallowances are addressed below, along with the issue of DTE Electric's modeling.

b. Emergent Replacements

This cost category includes the subcategories of Storm, Non-storm, and Substation Reactive. DTE Electric explains that a storm is defined as greater than 760 customer outage events impacting more than 200 circuits, and a non-storm is defined as fewer than 760 customer outage events for the entire distribution system. DTE Electric's initial brief, p. 53, notes 39 and 40; 6 Tr 3034, 3041. The company forecasts storm expenditures of $282 million for 2023, $244 million for 2024, and $251 million for the test year; and non-storm expenditures of $207 million for 2023, $220 million for 2024, and $227 million for 2025. 6 Tr 3034, 3043-3044; Exhibit A-12, Schedule B5.4, pp. 1-3. DTE Electric states that all projections are based on a five-year (2018-2022) inflation-adjusted historical average which is consistent with the method approved by the Commission in the company's last four rate cases. DTE Electric's initial brief, pp. 54-55. The company argues that 2023 is higher than the average due to the five catastrophic storms that occurred during that year.

i. Historical Adjusted Inflation and Blended Inflation Rate

The Attorney General proposes a reduction of $24.5 million to the 2024 projection and a reduction of $28.6 million to the 2025 projection for emergent replacements for two reasons. Attorney General's initial brief, pp. 14-20. First, while agreeing with the five-year average, the Attorney General argues that DTE Electric's inflation adjustment to the historical averages is simply a vehicle to "arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors." 6 Tr 3601. The Attorney General argues that:

> DTE arrived at its forecasted level of expenditures for emergent replacement programs by applying retroactive inflation adjustments to historical amounts from 2018 to 2022 and labeling them normalization adjustments. It then applied forecasted inflation factors for 2023, 2024, and 2025 to the adjusted five-year average cost base to determine the forecasted capital expenditures for the forecasted bridge periods and projected test year. The AG does not agree with that approach.

> DTE is simply compounding inflationary increases on top of inflationary increases that already occurred in the historical years.

Attorney General's initial brief, p. 15 (citing Exhibit A-12, Schedule B5.4, p. 3). The Attorney General contends that if any inflation was experienced by the company in those prior years, it is already reflected in the actual amounts and the amounts should not be inflated twice. She further argues that this adjustment is not applied consistently, stating that "the Company does not adjust all distribution historical capital expenditures, [nor any] of the non-distribution capital expenditures (such as generation or information technology), [or] O&M historical costs." Attorney General's initial brief, p. 16; Exhibit AG-56. The Attorney General contends that this practice also violates the Uniform System of Accounts, Electric Plant Instruction No. 2, because the normalization modifies actual costs. The Attorney General states that "[a]lthough the Commission accepted this approach with regard to emergent capital expenditures in Case U-20836, it has not been accepted for other capital expenditures or O&M expenses." Attorney General's initial brief, p. 16 (emphasis omitted).

Second, the Attorney General contends that the Commission has rejected DTE Electric's use of a blended inflation rate (using both Consumer Price Index (CPI) numbers and internal wage increase numbers) in this normalization adjustment. Exhibit AG-38; 6 Tr 3601; Attorney General's initial brief, pp. 15-16. However, the Attorney General does not argue the issue but refers to her discussion of this issue within the O&M Expense – Inflation Adjustment section of her brief. *Id*., p. 16. These arguments are described below.

Lastly, in a related argument, the Attorney General asserts that DTE Electric has not provided an analysis of the "offsetting effects of significant distribution capital investments on inflationary pressures on Emergent Replacements." 6 Tr 3601; Attorney General's initial brief, pp. 18-20. The Attorney General asserts that DTE Electric "is improperly conflating capital expenditure reductions from strategic capital expenditures and tree trimming costs, with efficiency costs savings that prior year Emergent Projects should have created." *Id*., p. 18 (citing Exhibit AG-56, pp. 8-10). The Attorney General contends that the company continues to fail to comply with the Commission's directive to supply such an analysis in the last three rate cases. Attorney General's reply brief, p. 16.

DTE Electric counters that "prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2022 dollars, consistent with the historical test year) because the value of a dollar decreases over time due to inflation. Omitting the adjustment would understate the amount of capital required to do the same scope of work in future years (Hill, 6T 3066-67)." DTE Electric's initial brief, p. 56. The company also argues that this method of adjustment was approved by the Commission in the May 8, 2020 order in Case No. U-20561 (May 8 order), p. 86, the November 18 order, p. 63, and the December 1 order, pp. 74-76; and that the Commission also approved use of the blended inflation rate in the November 18 order, p. 258, and the December 1 order, p. 193. DTE Electric posits that this type of constant dollar normalization is used by the U.S. Department of Defense. DTE Electric notes that the Attorney General acknowledges that the Commission accepted this adjustment approach in Case No. U-20836. DTE Electric's reply brief, p. 20.

DTE Electric further argues that the composite inflation rate best reflects the inflationary pressures faced by the company since labor costs are driven by collective bargaining agreements. 2 Tr 174; DTE Electric's initial brief, p. 57. Addressing the Attorney General's final argument regarding the potential offset, DTE Electric contends that:

> Exhibit A-12, Schedule B5.4, page 1, line 6, columns (e) and (f) show reductions in Emergent Replacements of $20,819,951 for 2024, and $21,435,815 in 2025. These savings are based on strategic capital investments and the tree trim surge program, calculated using the Company's reliability model. The Company provided the

> calculations as a workpaper with direct testimony (Kryscynski, 3T 366; Hill, 6T 3035, 3071; Exhibit A-52, Schedule QQ3).

Id.; DTE Electric's reply brief, p. 21.

Beginning with the Attorney General's historical inflation adjustment argument, the Commission recognizes that it has displayed some inconsistency with respect to this issue. In the December 1 order, p. 76, the Commission found that DTE Electric had "computed the historic average in a manner consistent with Case Nos. U-20836 and U-20561[,]" which is accurate as far as this adjustment application goes. However, also in the December 1 order, pp. 228-232, the Commission analyzed a very similar argument presented by the Attorney General and the Staff regarding the O&M costs for active healthcare. DTE Electric applied the same constant dollar averaging method used in the instant case for emergent replacements (and other capital expenditures) to the active healthcare expenses in that case. The Attorney General argued that "'[DTE Electric] is simply compounding inflationary increases on top of inflationary increases over the eight-year period from 2017 to 2024.'" December 1 order, p. 229 (quoting 6 Tr 3778 in Case No. U-21297). The Staff also opposed the constant dollar averaging and the company's "'use of three different rates of inflation for this highly volatile expense[.]'" December 1 order, p. 228 (quoting 7 Tr 4681 in Case No. U-21297). The administrative law judge recommended rejection of the constant dollar normalization proposed by the company for these O&M costs, which she found to be in line with Commission precedent on the issue of active healthcare expense. The Commission adopted the judge's recommendation, finding that the company "insufficiently demonstrated that its proposed constant dollar normalization will not result in compounded inflationary increases." December 1 order, p. 232.

In the instant case, regarding active healthcare costs, DTE Electric states that its increased projection "reflects the normalization of the 2022 Active Healthcare costs to reflect an historical average of constant dollar costs and thereby establish a sound starting point[.]" DTE Electric's initial brief, p. 247. Thus (and like emergent replacements), these expenses receive the same treatment by the company in the instant case as they received in Case No. U-21297. DTE Electric cites to cases in which the Commission has previously upheld this approach (November 18 order, p. 63, and December 1 order, p. 76) but both cites are to findings regarding the inflationary adjustment to emergent replacements (capital expenditures) in those cases, not to active healthcare expenses (O&M). DTE Electric's initial brief, pp. 249-250. The company notes that the Commission "previously declined to adopt the constant dollar normalization in this context" but contends that it has addressed the Commission's concerns. *Id*., p. 250.

In arguing against the company's normalization adjustment to these O&M costs, the Staff states as follows:

> The Company adjusted the Company's Active Healthcare base year expense with the "constant dollar" adjustment, as testified to by Jerome K. Hooper. (Hooper, 6 TR 2931.) This method has been consistently rejected by the Commission for healthcare projections. (Rueckert (Revised), 6 TR 4993.) The adjusted historic expense was projected forward with adjusted annual increase trends provided by independent healthcare experts Willis Towers Watson (WTW).

Staff's initial brief, p. 103 (footnote omitted). Similarly, the Attorney General states:

> As the AG has made clear in the past and as the Commission has agreed, the "constant dollar averaging" DTE likes is simply a process that increases actual historical costs in a way that is divorced from reality. It adds inflationary costs to historical costs, which already include inflationary pressure, thereby doubling down in a blatant attempt to abuse the projected test year method.

Attorney General's initial brief, p. 69. Significantly, in explaining how the active healthcare costs are adjusted, DTE Electric refers to its historical treatment of emergent replacements in capital expenditures. 6 Tr 2930-2935. DTE Electric's witness states that:

> [t]he only difference between the two normalization adjustments is that emergent replacement expenditures are adjusted for overall inflation as measured by the Consumer Price Index whereas the Active Healthcare normalization adjustment is

> based on actual historical national medical cost trends as measured by the PwC [Pricewaterhouse Coopers International Limited] actual medical cost increases. This difference in historical bases for escalation recognizes that overall inflation is an inappropriate measure of historical medical cost escalations.

6 Tr 2934-2935. The Commission observes that the company's responses to the Attorney General's attempts to elicit additional support for the constant dollar normalization approach are not illuminating. *See*, Exhibit AG-56, pp. 1-13.

The Commission notes that no year within the 2018-2022 five-year average period nor any year in the bridge or test periods is actually inflated twice. That said, the Commission agrees with the Attorney General that the application of historical inflation to the emergent replacement capital expenditures is unwarranted. As it did with respect to these O&M costs in the December 1 order, the Commission finds that DTE Electric has not provided a convincing argument that it is necessary to inflate the years within the five-year average. When asked for evidence that historical costs actually increased by the inflation factors that the company applied, DTE Electric provided the following testimony:

> Actual historic capital expenditures only include inflation incurred in the years leading up to and during that year. Using 2019 historic capital expenditures as an example, they include inflation incurred from prior years and in 2019. However, for calculating a baseline from which to forecast future emergent replacements it is necessary to adjust the 2019 historic capital expenditures with inflation seen from 2019 through 2022.

6 Tr 3067 (cited in Exhibit AG-56, p. 7). That is the extent of the company's justification. The Commission is not persuaded and agrees with the Attorney General that if any inflation was experienced by the company during those prior years, that inflation is already reflected in the actual amounts. The Commission observes 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. However, Exhibit A-12, Schedule B5.4, p. 3, shows downward

trends for emergent replacements (storm) in 2020 and 2022 (2 years out of 5), and for emergent replacements (substation reactive) in 2019, 2020, and 2022 (3 years out of 5). The costs reflect variability but no consistent upward trend. The Commission finds that the application of forecasted inflation factors to a simple five-year average for 2023, 2024, and 2025 is appropriate, but the prior historical adjustment that the company uses in the instant case, and which DTE Electric has now expanded to several other capital expenditure categories (Connections and New Load, Relocations, Electric System Equipment, Normal Retirement Units Changeout (NRUC) and Improvement Blankets, and General Plant, Tools & Equipment) is not. *See*, Exhibit A-12, Schedule B5.4, pp. 4-9. The Commission finds that the historical inflation adjustment for 2018-2022 to all of these proposed expenditures should be removed. (The Commission makes the same finding for active healthcare costs, which is discussed below.)

The Commission further finds that, while DTE Electric did present some evidence regarding the offsetting effects of significant distribution capital investments as described above, the company 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.'" December 1 order, p. 74 (quoting the PFD in that case, p. 202, which is quoting the November 18 order, p. 63). The Commission has been seeking convincing evidence through several rate cases. In the company's next rate case, DTE Electric shall present evidence on the continuing need for *any* inflationary adjustment to these expenditures.

Turning to the question of the inflation rate to be applied, the Commission approves the company's use of its blended rate, which is consistent with the November 18 order, p. 258, and the December 1 order, p. 193. DTE Electric provided evidence that the composite inflation rate "separates labor inflation, which is subject to Company-specific dynamics like collective bargaining agreements, from non-labor inflation. 2 Tr 174; DTE Electric's initial brief, p. 57. 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. 2 Tr 175. 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.

Having approved the use of the blended rate, the Commission finds that the removal of the 2018-2022 historical inflation adjustment to emergent replacements results in a disallowance of $44.46 million for 2024 and $45.75 million for the test year.

ii. Four-Year Average and Inflation Rate

In addition to the Attorney General, ABATE proposes a $122.89 million reduction to emergent replacements based on a four-year average (2018, 2019, 2020, 2022) for storm related emergency replacements rather than the five years proposed by the company, arguing that 2021 should not be included because of the abnormal amount of storm activity that year. 6 Tr 3357-3359; ABATE's initial brief, pp. 14-15. ABATE argues that data from 2021 unreasonably skews the five-year average, and notes that even though 2023 was also an anomalous year, spending in 2021 was still significantly higher than in 2023. ABATE also argues that the Real GDP Chained Price Index should be used to project inflation on base capital. *Id*., p. 15; 6 Tr 3358-3359. ABATE contends that the costs of response for the 2021 storms were more than double the costs "for 2018 through 2021 and nearly double the Company's expenditures in 2022." ABATE's reply brief, p. 9.

DTE Electric counters that ABATE's proposal undermines the intent of using an average, and that 2023 was actually worse than 2021. DTE Electric's initial brief, p. 58. The company contends that the Commission has repeatedly approved the five year average, and that the CPI-U is a widely used measure of inflation that has also been approved by the Commission. DTE Electric argues that ABATE failed to show how the alternative is superior. 2 Tr 175-176; 6 Tr 3072-3075; DTE Electric's reply brief, p. 21.

The Staff also disagrees with ABATE's proposal, arguing that it would not be appropriate to exclude 2021 from the five-year average. Staff's initial brief, p. 45.

The Commission rejected ABATE's proposed exclusion of 2021 in the December 1 order, p. 97, and sees nothing on the instant record that persuades the Commission to deviate from that decision. As the Commission noted in that order, high variations in weather are becoming the norm and the Commission supports the use of the five-year average. The Commission also rejects the proposal to switch to use of the Real GDP Chained Price Index. As the company points out, 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. 6 Tr 3342; 2 Tr 175-176; 6 Tr 3075. ABATE testified that even the Real GDP Chained Price Index does not cure ABATE's primary concerns involving employee tenure and productivity impacts. 6 Tr 3342.

c. Customer Connections, Relocations, and Other Investments

DTE Electric states that it forecasts its 2024 and 2025 capital expenditures for this cost category using a three-year (2021-2023) inflation-adjusted average which is consistent with the Commission's approval in the December 1 order, with the exception of two projects: the I-375 relocations project and the Incremental Infrastructure for EV project. 6 Tr 3049-3050; DTE Electric's initial brief, p. 61.

i. Inflation Adjustment

For Electric System Equipment, the Attorney General proposes reductions of $3.15 million for 2024 and $3.45 million for 2025; and for General Plant, Tools & Equipment and Miscellaneous, the Attorney General proposes reductions of $1.76 million for 2024 and $1.86 million for 2025, again based on her disagreement with the company's inflation adjustment method (as seen above under emergent replacements). 6 Tr 3612-3613; Attorney General's initial brief, pp. 25-26; Attorney General's reply brief, pp. 17-18. The Attorney General argues that "the Company improperly inflates actual historical capital expenditures to create a larger cost base on which to add future inflation adjustments." 6 Tr 3604.

DTE Electric again counters that this is the appropriate way to express a constant-dollar denomination in order to avoid understating the amount of capital required to do work in future years, and argues that it has the Commission's approval. DTE Electric's initial brief, p. 61; DTE Electric's reply brief, p. 22.

The Commission adopts the decision rendered above in Section V.B.4.b.i. for this cost category. The Commission again notes that these cost categories, which are based on a 2020-2022 three-year average, do not exhibit a consistent trend upwards: Electrical System Equipment trended downwards in 2021 (1 year out of 3), NRUC and Improvement Blankets trended downwards for both 2021 and 2022 (2 years out of 3), and General Plant, Tools & Equipment trended downwards in 2021 (1 year out of 3). Exhibit A-12, Schedule B5.4, pp. 6-9. For Electric System Equipment, this results in a disallowance of $2.55 million for 2024 and $2.62 million for 2025; and for General Plant, Tools & Equipment, this results in a disallowance of $607,000 for 2024 and $625,000 for 2025. The Commission notes that this decision also results in a disallowance for NRUC and Improvement Blankets of $1.74 million for 2024 and $1.79 million for 2025; and results in an increase for Customer Advance for Construction of $1.7 million in 2024 and $1.76 million in 2025. *See*, 6 Tr 3053-3054; Exhibit A-12, Schedule B5.4, pp. 4-9.

ii. Customer Connections and New Load

For this cost category, the Attorney General proposes a reduction of $14.45 million for 2024 and an increase of $3.4 million for the test year based on the 2021-2023 average but without the inflation adjustment that the company adds. 6 Tr 3603-3607. Regarding the inflation adjustment, the Attorney General asserts that:

> the Company expanded the use of inflation adjustments to historical costs to other type[s] of capital expenditures . . . The Commission has not previously addressed this issue and in the past has approved the AG's approach of using actual historical costs without historical inflation adjustments. DTE was asked about this in follow up discovery and in response, the Company points to DR 1.26c, which contains some language from the U-21297 order [December 1 order, pp. 78-81]. However, that reference response pertains to *surge savings* and not Customer Connections etc., and as such is irrelevant to the discussion and should be disregarded.

Attorney General's initial brief, p. 21 (citing Exhibit AG-56, pp. 11-12) (emphasis in original). The Attorney General also applies data regarding Michigan housing starts which forecasts a decrease of 3.8% in 2024 and an increase of 10.8% in 2025. 6 Tr 3606-3607; Attorney General's initial brief, pp. 21-22. The Attorney General argues that the "use of future housing starts is a superior approach because it creates a link to a factor that drives customer connections" and is the best objective proxy. Attorney General's reply brief, p. 18. Based on her analysis of historical actual amounts and her forecast of new connections, the Attorney General proposes a reduction of $14.45 million to 2024 and an increase of $3.4 million to 2025. 6 Tr 3607.

DTE Electric counters with the same argument regarding the inflation adjustment and constant dollar averaging as is described above. DTE Electric further argues that the Attorney General's housing starts forecast is inappropriate because the activities that are funded in this category go beyond just housing starts (new connections) and includes upgrades and business expansion. 6 Tr 3080; DTE Electric's initial brief, p. 62; DTE Electric's reply brief, p. 22.

Regarding the inflation adjustment, the Commission adopts the decision rendered above in Section V.B.4.b.i. which results in a disallowance for Customer Connections and New Load of $11.58 million for 2024 and $11.92 million for 2025; and in a disallowance for Relocations of $1.84 million for 2024 and $1.89 million for 2025. Like the cost categories discussed just above, these also relied on a three-year average and also failed to show a consistent trend upwards, though not across the board: certain categories within Connections and New Load went down in 2022 (1 year out of 3), and certain categories within Relocations went down in 2021 and 2022 (2 years out of 3). Exhibit A-12, Schedule B5.4, pp. 4-6.

The Commission is not persuaded to adopt the Attorney General's housing starts forecast. *See*, 6 Tr 3606-3609. DTE Electric relied on an historical three-year average, and also showed that this cost category must respond to more than just new housing, including upgrades to existing housing, work for non-residential customers, and resolving circuit loading issues. 6 Tr 3050-3051, 3080. DTE Electric and the Attorney General appear to agree on a forecasted 10% increase for the test year. The Commission is not convinced that DTE Electric's forecast is excessive and rejects the Attorney General's proposed disallowances based on housing starts.

The Attorney General also proposes a reduction of $3.73 million for 2024 and $10.17 million for the test year associated with utility make ready (UMR) projects that support EV adoption. 6 Tr 3607-3609; Attorney General's initial brief, pp. 22-24. The Attorney General argues that the market for EV adoption is smaller than what is forecast by the company. She contends that DTE Electric has not supported its request to increase UMR capital spending almost 200% over 2022 actual net spending in this category. The Attorney General states that in rebuttal testimony DTE

Electric "admits that EV adoption is growing at a slower pace than prior projections and notes that the Energy Information Administration (EIA) projects that 16% of new vehicle sales will be electric by 2032, well below DTE's forecast of 22% by 2028." *Id*., p. 23. The Attorney General contends that DTE Electric has an incentive to inflate this forecast but has not produced evidence showing that a 200% increase in net spending over actual 2022 UMR spending in this category is justified. Attorney General's reply brief, p. 19.

MEIU counters that the Attorney General fails to provide evidence supporting her lower forecast, other than news articles that cover a short period of time. MEIU's initial brief, pp. 29-31. MEIU notes that DTE Electric does not rely on EIA data but rather uses multiple credible sources plus data from the company's experience within its own service territory. 6 Tr 1940-1941. MEIU argues that the company's EV adoption forecast is too low. 6 Tr 4062. They argue that the Commission should ignore the Attorney General's proposal for reductions to this UMR funding. MEIU's reply brief, pp. 2-3. MNSC also argues that the Attorney General's forecast is mistaken. MNSC's initial brief, p. 119.

EVgo also disagrees with the Attorney General's claim that EV adoption is waning and supports the company's forecast. EVgo's initial brief, pp. 24-25 (citing 6 Tr 3318).

DTE Electric counters that it must ensure that the grid is ready for EV adoption. 6 Tr 3081; DTE Electric's initial brief, p. 62; DTE Electric's reply brief, p. 23.

The Commission approves DTE Electric's UMR projections related to the EV forecast. While agreeing with the Attorney General that these projections are subject to uncertainty, the Commission finds the Attorney General's proposal of simply using the 2023 amount plus inflation to be too low. In this highly changeable arena, the Commission currently finds the company's forecast to be more credible than either the Attorney General's or MEIU's.

iii. I-375 Relocation Project

DTE Electric reports that it has been notified by the Michigan Department of Transportation (MDOT) that it must relocate distribution infrastructure located in the I-375 corridor. Exhibit A-12, Schedule B5.4, p. 7; 6 Tr 3052-3053; DTE Electric's initial brief, p. 63. The Attorney General proposes a full disallowance of $25 million for 2024 and $8 million for 2025 on grounds that the proposed spend is premature because the project is very likely to be delayed. 6 Tr 3611; Attorney General's initial brief, p. 24. She argues that there are no definitive timelines for this project and that, if the company incurs costs in 2024 or 2025 it may recover them in the next rate case.

DTE Electric counters that it has received a notice to vacate and it is unreasonable to assume that no work will be done in 2024 and 2025. Additionally, the company notes that its updated forecast seeks only $8.84 million for 2024 and $13.8 million for 2025. DTE Electric's initial brief, p. 63; 6 Tr 3083-3084; DTE Electric's reply brief, p. 23. The updated forecast shows a total reduction of about $10.3 million and a shift of costs from the bridge period to the test year.

The Attorney General responds, arguing that the fact that the forecast has changed during the short duration of this proceeding shows the uncertainty of this spending. Attorney General's reply brief, p. 20.

The Commission approves DTE Electric's revised projections, reducing the original total projection by $10.36 million. DTE Electric, in rebuttal, changed its projections based on known delays; conversely, the Attorney General did not present evidence demonstrating that additional delays would occur. The company showed that MDOT plans to begin construction in 2025, and that the company began work in 2023. 6 Tr 3052-3053, 3082-3083. The Commission approves the revised forecast of $8.84 million for 2024 and $13.8 million for 2025.

d. Strategic Capital

DTE Electric projects total spending on strategic capital programs of $2.337 billion, of which $827.3 million is projected for the test year. Exhibit A-12, Schedule B5.4, p. 1. These programs are divided into the three subcategories of (1) infrastructure resilience and hardening, (2) infrastructure redesign and modernization, and (3) technology and automation. Exhibit A-12, Schedule B5.4, p. 1; DTE Electric's initial brief, pp. 63-64.

ABATE argues that the Commission should approve projected spending on strategic capital only for projects that are expected to be in service during the bridge period and test year, which results in a reduction of $613.59 million in projected capital expenditures for strategic capital. ABATE's initial brief, pp. 15-17; 6 Tr 3359-3361. ABATE contends that the increased spending on strategic capital and the associated rate increases have not produced corresponding improvements to service, and notes that some in-service dates range as far as 2035. ABATE asserts that DTE Electric routinely underspends on strategic capital and diverts those funds to emergent replacements, while customers have seen little improvement in reliability metrics. ABATE's reply brief, pp. 10-11.

MNSC states that they share ABATE's concern that projects not in service until beyond the test year "are not providing benefits to ratepayers" and that "CWIP recoverability is insufficient support for the reasonableness of DTE's investments in projections years away from completion." MNSC's reply brief, pp. 7-8.

DTE Electric counters that the Commission rejected this argument in the December 1 order, p. 94, and contends that project costs may be included in rate base if they are reasonable and prudent, whatever their in-service date may be. The company also notes that capital expenditures on projects that will not be in service during the test year have no current revenue requirement because, under the May 10, 1976 order in Case No. U-4771, CWIP may be included in rate base but is offset by AFUDC. DTE Electric's initial brief, p. 65; DTE Electric's reply brief, p. 24. DTE Electric further notes that, if the Commission adopted ABATE's proposal, then it should direct a corresponding adjustment to pre-tax AFUDC to offset the removal of these projects. 6 Tr 1568.

The Staff also opposes ABATE's proposal. The Staff indicates that it "is not opposed to most of the spending requested in the strategic capital programs. Staff also acknowledges that with the results of the Liberty audit now available, the spending priorities of the Company may soon shift. (6 TR 5157.)" Staff's initial brief, p. 193. The Staff argues that "whether a project will be completed within the test year does not determine if it is reasonable and prudent enough to include in rate base." *Id.*, p. 194.

As with the Attorney General's argument above regarding nuclear generation, the Commission is not persuaded to reject programs and projects for inclusion in rate base on the basis of their in-service date, and nothing in the evidentiary record regarding strategic capital convinces the Commission to alter that finding. The Commission rejects ABATE's proposal for the reasons articulated above in Section V.B.3.b.i. of this order.

e. 2022 Actual Expenditures Compared to the Case No. U-21297 Forecast

DTE Electric contends that parties should not be relying on differences between actual expenditures for 2022 and the forecasts provided in Case No. U-21297 as a basis for objecting to projected expenditures in the instant case, labeling this as the use of hindsight. DTE Electric's initial brief, p. 67; DTE Electric's reply brief, p. 24. The Attorney General responds that it is "proper to use such benchmarks to inform decisions about the reasonableness and prudence of certain actual DTE expenditures that are not currently in rates, as well as DTE's future projections." Attorney General's reply brief, p. 21.

These arguments were not well fleshed-out by the parties and the Commission finds that no decision is required. The utility, the Staff, and the intervenors routinely rely on data associated with the historical year in rate cases. Beyond that, the Commission does not opine.

f. Alignment with the Distribution Grid Plan

DTE Electric explains that on September 29, 2023, the company filed an updated DGP in Case No. U-20147; that the "DGP supports the development of the investments that are the basis of this case[;]" and that the alignment between the DGP and the instant case illustrates "the Company's long-term plans and larger strategy for improving the strength of the distribution system." 3 Tr 323; Exhibit A-23, Schedule M8.

The Staff recommends that the Commission direct DTE Electric to improve the alignment between the DGP and its rate case evidence and better communicate the reasons for increases or decreases in spending categories that appear in rate cases. 6 Tr 5041; Staff's initial brief, pp. 171-174. The Staff also proposes an annual update to the DGP as a way communicating such changes. *Id.*, p. 173.

DTE Electric indicates its support of both of these recommendations. DTE Electric's initial brief, p. 69. The company indicates that the largest variants between the 2023 DGP and the instant case resulted from emergent replacements, tree trimming, and infrastructure resilience and hardening. 3 Tr 442. The company states that it "will work toward minimizing changes to planned investments between the rate case and DGP filings, and when strategic changes are necessary after the DGP filing, the Company will work with Staff to coordinate these changes with increased transparency (Kryscynski, 3T 441-43)." DTE Electric's initial brief, p. 69. The company states that it will also coordinate with the Staff to develop an update process. *Id*.

MNSC states that it does not oppose the update but notes that the information in Case No. U-20147 "is not a substitute for proving the reasonableness and prudence of spending strategies and plans." MNSC's reply brief, p. 8. MNSC goes on to state that:

> Staff's position appears to reflect a perspective that spending levels in the rate case should align with those in the DGP. MNSC strongly disagrees. DGP spending appears to reflect the Company's aspirational spending goals and insufficiently addresses cost-effective reliability benefits and affordability impacts. Unless and until the grid plans are subject to a contested docket and regulatory approval, the Commission should treat them as merely informational. If Staff has concerns about spending deviations between the DGP and rate case, it may explore them through discovery in the rate case as it did in this proceeding. Requiring annual updates to the DGP complicates that docket and has the effect to impose more weight on grid plans in the rate case than they are rightly due. The Commission should reject Staff's request, irrespective of the Company's willingness to comply. Instead, the Commission adopt [sic] MNSC's suggestions to improve the robustness and credibility of grid planning.

Id., p. 9 (citations omitted).

The Commission acknowledges the fact that DGP proceedings are not contested cases and are not subject to the same level of analysis and scrutiny as is applied in a rate case. The Commission is in the process of reviewing the requirements for and interaction of DGPs, TEPs, and rate cases in Case Nos. U-21637 (rate case process improvements), U-21492 (TEPs), and U-20147 (distribution planning), and the DGP straw proposal is currently out for comment in Case No. U-20147. The Commission looks forward to making changes and improvements to these processes to better align and produce more streamlined, coordinated results. This process is underway in all three interconnecting dockets. In the interest of making interim improvements, the Commission approves the Staff's recommendations and directs DTE Electric to work with the Staff to develop a process for regularly updating the DGP between filings, to ensure that increases and decreases to proposed spending that appear in the rate case but fail to conform to the current DGP are adequately explained.

g. The Quality of the Global Prioritization Model

DTE Electric explains that the GPM was developed by its DO team:

> to prioritize investments by ranking projects and programs based on the benefits the project or program delivers for a given level of investment. The ranking is done by evaluating a project or program across ten impact dimensions (listed and summarized in Table 7 at Kryscynski, 3T 351) that represent project benefits, and developing a total project score based on the weighting of each impact dimension. The benefits of strategic investments relate to five planning objectives: (1) Safe, (2) Reliable and Resilient, (3) Affordable, (4) Clean, and (5) Customer Accessibility and Community Focus (listed in Table 6 at Kryscynski, 3T 349), which align with the Commission's overarching objectives for the electrical distribution system of safety, reliability and resilience, cost effectiveness and affordability, and accessibility (October 11, 2017 Order in Case No. U-18014, pp 10-12; August 20, 2020 Order in Case No. U-20147, pp 36-38). The GPM results serve as the initial basis for the Company's investment prioritization and highlight the projects that have the highest relative benefit for improving the grid and the overall customer experience, and/or are most urgent (Kryscynski, 3T 346, 349-51, 355, 420-21).

DTE Electric's initial brief, p. 70. DTE Electric reports that the GPM was also updated in 2023 to add three new dimensions, including the "investment in EJ [environmental justice] communities" dimension, in response to the November 18 order, pp. 458-459. DTE Electric further states that:

> [i]n response to the Commission's guidance in the Company's last rate case concerning the DGP, GPM, and benefit-cost analysis (BCA) (December 1, 2023 Order in Case No. U-21297), the Company's distribution investments in this case are further supported by (1) the level of detail on project purpose, scope and benefits in the capital summaries (Exhibit A-23, Schedules M5, M6, and M7); (2) a new BCA methodology for PTMM and Undergrounding, with BCA spreadsheets and calculations provided in this case; and (3) a more comprehensive, circuit-level, reliability model to help tie potential investments in six key investment areas (Tree Trimming, 4.8kV [kilovolt] Hardening, PTMM, Customer Excellence, Distribution Automation, and 4.8kV Conversion) to future reliability improvements. The Company also submitted a working version of the GPM and the Reliability Model as a workpaper in its initial filing and as an Exhibit in rebuttal (Exhibit A-43, Schedules HH4 and HH5; Exhibits MEC-71 and MEC-72) to allow for a detailed review of the prioritization process. The Company intends to continue enhancing its investment analysis, but notes that not every grid/reliability investment can be

> effectively translated into a monetized valuation (Kryscynski, 3T 415-16, 475. See also 3T 532-33, 595-96).

DTE Electric's initial brief, p. 71. The company notes that the GPM does not determine whether benefits exceed costs because only two captured benefits (O&M avoidance and capital avoidance) are monetized. *Id*. However, DTE Electric reports, strategic investments are assessed, scored, and ranked in a quantitative manner and hundreds of projects and programs are prioritized. 3 Tr 353-357. Exhibit A-23, Schedule M14 (the GPM) provides the complete rankings, and the top 50 strategic capital investments are listed on Table 9 at 3 Tr 357. Based on the model and the proposed investments, DTE Electric predicts that customers will experience an all-weather SAIDI of 504 minutes in 2024 and 482 minutes in 2025, as compared to a historical baseline of 563 minutes; and an all-weather SAIFI of 1.31 in 2025 as compared to a historical baseline of 1.37. DTE Electric's initial brief, p. 75 (see footnotes 52 and 53 for corrections to the record).

MNSC provides extensive criticisms of the GPM, the DGP, and the reliability model (RM). MNSC's initial brief, pp. 8-45; *see also*, pp. 45-115.[15] MNSC argues that increased DO capital spending will not bring about the reliability results that are promised, contending that "the regulatory incentive for capital spending may influence the utility's preference for capital projects, as evidenced by the Company's spending plan through at least 2028." *Id*., p. 8. MNSC contends that there is a disconnect between the causes of the company's poor reliability and the spending plan. MNSC argues that DO capital spending has steadily increased since 2015 while performance has steadily deteriorated. MNSC urges the Commission to slow the capital spending because DTE Electric's proposals are premature and inadequately supported.

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[15] In the Attorney General's reply brief, pp. 21-22, she indicates that she relies on the "analysis and recommendations as laid out in MNSC's initial brief [pp. 8-115] to support rejection of DTE's filed positions and adoption of more reasonable numbers." *See also*, Attorney General's initial brief, pp. 84-90.

MNSC notes that the GPM provides the foundation for DTE Electric's strategic capital requests. *See*, 4 Tr 346-361; Exhibit A-23, Schedule M14; MNSC's initial brief, p. 11. MNSC further notes that this is the first proceeding where the GPM has been made available to the Commission and the intervenors, with a read-only version appearing at Exhibit A-43, Schedule HH4, and a working version appearing at Exhibit MEC-71. MNSC states that the GPM "scores distribution capital programs and projects across 10 weighted 'impact dimensions' then ranks each program/project relative to the other programs/projects being scored and ranked. The main output of the GPM is a Top 50 list with scores." MNSC's initial brief, p. 11 (citing 3 Tr 346-357, 471-475, and Exhibit A-23, Schedule M14).

MNSC argues that most of the GPM inputs are not based on data but rather on subjective information, thus making the model vulnerable to manipulation. 6 Tr 3959; MNSC's initial brief, pp. 12-16. MNSC observes that the company presents different lists depending on why the list is being generated, noting that different Top 50 lists were produced in Case No. U-21297, in the 2023 DGP, and in the instant case. MNSC states that "[o]ver the course of about 12 months, [distribution and outage management programs] went from top rank to absent to top rank." *Id*., p. 12. They argue that the model can be manipulated by selecting which projects and programs to include for ranking. MNSC also argues that there is subjectivity in the scoring, because the scoring is based on "subjective GPM inputs from DTE's modeling, engineering, and other teams." *Id*., p. 13 (citing 6 Tr 3960, 3 Tr 513-517, 528-529). MNSC contends that DTE Electric's subject matter experts (SMEs) also select the risk probability, which is manually entered, along with the relative size of the expected benefit. Thus, MNSC argues, project benefits are an input to the model rather than something that the model generates. MNSC asserts that the SMEs also assign the probability that a project will achieve the projected benefit, adding another layer of subjectivity. MNSC argues that cost input is also manipulated and they provide a chart showing the substantial cost differences within the GPMs provided in Case No. U-21297 and the instant case. *Id*., p. 15.

MNSC argues that the GPM should not be evaluating both projects and programs. 6 Tr 3960-3962; MNSC's initial brief, pp. 16-20. MNSC complains that this method means that "any mile of PTMM outranks every substation project." *Id*., p. 16. MNSC asserts that the GPM provides no information on cost effectiveness, but rather is used to justify investment decisions rather than to guide those decisions. MNSC also argues that the company approves large projects independently of the GPM in any case, and that the company is unlikely to abandon an ongoing project if its ranking drops. MNSC avers that even if some inputs are objective, the score is based on multiple subjective assessments. *Id*., p. 18.

MNSC goes on to criticize the RM, for which a read-only version is available at Exhibit A-43, Schedule HH5, and a working version is available at Exhibit MEC-72. Per MNSC, DTE Electric relies on the RM to support proposed expenditures for the six programs of tree trimming, distribution automation, PTMM, customer excellence, 4.8kV hardening, and 4.8kV conversions. 3 Tr 361-366. MNSC argues that the RM provides only unsupported projections of reliability benefits. MNSC's initial brief, pp. 21-23. MNSC states that the RM uses only 10 months of data (January to October) for 2017-2022 and has not been updated to include 12 months. MNSC also observes that the RM begins its analysis of benefits only in the year of treatment (such as trimming or hardening) and compares it to the years after treatment, rather than showing the years before treatment compared to the years after treatment; and the RM always assumes that treatment occurs mid-year, so that benefits that may occur in Year 0 are halved. *Id*., p. 23; 3 Tr 557-558; 6 Tr 928-930; Exhibits MEC-4, MEC-70.

MNSC further argues that the reliability program analysis (RPA) does not provide credible support for the RM, particularly with respect to tree trimming, 4.8kV hardening, and PTMM (where it provides only indirect support). Exhibit A-43, Schedule HH6; MNSC's initial brief, pp. 24-36. Starting with tree trimming, MNSC argues that the model simply assumes benefits, and the assumed reductions do not align with the outage reductions reported in the company's regular tree trim reports. Exhibit MEC-72; MNSC's initial brief, p. 24. MNSC contends that five years of enhanced tree trimming program (ETTP) reports suggest that "tree trimming is unlikely to reduce outage events to the extent reflected in the [RPA and RM], undermining the credibility of both." *Id*., p. 25. Turning to 4.8kV hardening, MNSC again argues that the benefits are inflated, only ten months of data are used, the sample size is small, and the data does not align with other data presented by DTE Electric. MNSC states:

> Company witness Elliott Andahazy presented an evaluation of 4.8kV circuits one-year after hardening in all-weather conditions, which shows 38% reductions in event frequency (SAIFI) and 65% in SAIDI one year after hardening. The Company's evaluation of hardened 4.8kV circuits excluding MEDs [major event days], comparing 3-year average before and after hardening, showed 44% improvement in all-weather customer interruptions. Neither comes close to the Reliability Program Analysis and Reliability Model assumptions that the 4.8kV Hardening program reduces non-tree ex-MED [excluding major event days] outages by 70-80% in the first 3 years after hardening. Moreover, those Company evaluations of Hardening benefits likely exaggerate its benefits by conflating tree trimming and hardening into the same assessment.

Id., pp. 27-28 (citing 4 Tr 917, 928-929, 1034). MNSC notes that many circuits hardened in 2020 and 2021 performed slightly worse the year of and after hardening compared to the years before hardening, and they posit that most of the benefits from hardening result from tree trimming and not from equipment replacements. MNSC's initial brief, pp. 28-30. Turning to PTMM, MNSC argues that the benefit methodology is internally contradictory and only indirectly supported by the RPA, relies on partial years, and most circuits performed worse the year after PTMM treatment compared to preceding years. *Id*., pp. 30-36.

MNSC argues that the RM has additional flaws. MNSC notes that the RM classifies all outages that are not tree related as being caused by equipment failures; thus, this category includes the non-tree categories of Unknown, Animal, Weather, Loading, etc. MNSC states that "DTE analyses show Equipment causes a fraction of outages – 33.2% of SAIFI (ex-MEDs), 20.8% of outage events (including MEDS)." *Id*., p. 38 (citing 3 Tr 411 and Exhibit A-23, Schedule M8 (the 2023 DGP), p. 42). MNSC notes that the RM uses a baseline that pre-dates the ETTP, and converts outages to interruptions and minutes based on circuit averages rather than on actual circuit conditions or customers. For all of these reasons, MNSC posits that the RM overstates the benefits of PTMM, conversion, and hardening, and they recommend that the RM be updated for full year data and better validated. MNSC argues that massive increases to DO capital spending on equipment replacement is misguided, because the data shows that such spending is already taking place and reliability has worsened during that time. MNSC's initial brief, pp. 40-41. MNSC argues that, after blaming trees and wind as the leading causes of outages in the 2023 DGP, the company "rebutted the 2023 DGP analysis with a new analysis suggesting Equipment is the lead cause when considering the subset of data that excludes MEDs and a different period (2019-2023 versus 2018-2022). MNSC renews the request that the Commission strike this improper rebuttal."[16] *Id*., p. 42 (citations omitted). MNSC urges the Commission to direct DTE Electric to

[16] On September 4, 2024, the ALJ granted MNSC's motion to strike in part and denied it in part. 2 Tr 52-57, 61. MNSC apparently seeks leave to appeal under Mich Admin Code, R 792.10433(5) (Rule 433(5)), though MNSC offers no argument disputing the ALJ's findings. The Commission finds the ALJ's ruling to be reasonable and declines to find that a different result is more appropriate under Rule 433. *See*, June 5, 1996 order in Case No. U-11057, p. 2. The ALJ found that Mr. Kryscynski's rebuttal is responsive to Mr. Alvarez's and Mr. Stephens' testimony. 2 Tr 56-57. The Commission agrees.

accurately document outage classifications in order to identify equipment failures as a cause.

MNSC recommends the use of risk-informed decision support (RIDS) "to optimize capital budgets and select projects when affordability and other restraints constrain capital spending." 6 Tr 3963-3965; MNSC's reply brief, pp. 9-12. Acknowledging that RIDS was developed in California over many years and has had many iterations, MNSC states that they agree with DTE Electric that RIDS could be tailored to apply to Michigan investor-owned utilities (IOUs). *Id*., p. 11. MNSC contends that they have provided evidence showing accurate prioritization of projects, and that the Commission "should begin the process to tailor a RIDS-type methodology to Michigan utilities." *Id*., p. 12. MNSC further argues that they support improvements to the BCA and the distribution automation prioritization model, and the first improvement must be to improve the outage management system (OMS) so that actual failure rate data can be collected.

The CEOs commend DTE Electric for its introduction of several new analytical models, but also recommend upgrades to those models, particularly the RM and the distribution automation model. 6 Tr 3243; CEOs' initial brief, pp. 10-15; CEOs' reply brief, pp. 2-4. The CEOs argue that the company should use actual performance data in each of the models rather than "assumptions and estimates generated by subject matter experts." *Id*., p. 2. The CEOs argue that DTE Electric committed to this improvement at 3 Tr 447-448. The CEOs contend that the scope of the models should be expanded to include more programs, and that BCAs should be provided for more programs than just PTMM and undergrounding and should include hardening, conversions, distribution automation, and subtransmission redesign and rebuild.

The Attorney General also supports greater use of robust BCAs and quantifiable metrics. Attorney General's reply brief, p. 22.

On the topic of scoring and risk, DTE Electric counters that the GPM considers other benefits besides risk reduction, and that the different metrics mean different things and do not overlap. DTE Electric's initial brief, p. 76. The company also argues that the GPM is based on objective inputs and on subject matter expertise, and that subjective topics still have a quantitative basis. DTE Electric states that, for the 138 projects scored in the GPM, "five dimensions (Reduce Electrical Hazards, SAIDI, SAIFI, O&M Avoidance, and Capital Avoidance) are calculated entirely on objective information and contribute 45% of the overall scoring" and there is "also 18% for Investment in EJ Communities (using the MiEJScreen score . . .), so total scoring in the GPM is 63% objective." *Id*.

On the topic of subjectivity, DTE Electric counters that most of the GPM inputs are objective and the methods are applied uniformly. The company notes that it has taken feedback from interested persons resulting from technical conferences and DGP filings, and has provided the entire model in this case. DTE Electric states that the challenges associated with comparing projects and programs is one of the reasons that the GPM was developed. DTE Electric's initial brief, p. 77. The company also notes that tree trimming is an O&M expense (or a regulatory asset), so it is not included in the GPM because it is too fundamental to be prioritized, and it also has its own model, which is the Surge Model (Exhibit A-22). Regarding RIDS, DTE Electric contends that RIDS was designed to address large scale California public safety risks such as earthquakes and wildfires, and is also very complex, making it necessary to tailor it to Michigan. *Id*., pp. 78-79. The company also contends that Mr. Alvarez's example of how to select investments under his alternative methodology contains mathematical errors.

Regarding the expansion of the IRM and tree trimming, DTE Electric counters that the RM is only one component of support for the company's six reliability improvement programs and additional support appears in testimony and in the GPM. The company responds that it does not use the reliability modeling approach that MNSC assumes it uses (difference of differences), but rather uses the approach provided in discovery as Exhibit A-43, Schedule HH6. 3 Tr 435-437; DTE Electric's initial brief, p. 80. DTE Electric further argues that the RM separates tree trimming from strategic capital because it calculates the benefits separately (tree and non-tree) for events and for outages, and the model also uses multiple years of baseline reliability to account for weather variation. *Id*.; 3 Tr 437-438. The company asserts that it uses accurate units and criticizes the unit cost analysis method promoted by MNSC, contending that MNSC's costs "are off by a factor of ten" and offering other criticisms. DTE Electric's initial brief, p. 81.

On the topic of poor reliability, DTE Electric counters that MNSC misunderstands the evidence. The company argues that its SMEs "use many factors to determine equipment life expectancy (including age but not depreciation status) in estimating investment needed for equipment replacements (Kryscynski, 3T 309, 405-406)." DTE Electric's initial brief, p. 82. DTE Electric argues that it began the tree trim surge program in order to address the fact that vegetation is indeed a significant cause of outages. But the company argues that addressing vegetation alone will not solve the problem because the underlying equipment is not resilient enough to withstand increasingly harsh weather. 3 Tr 406-408; DTE Electric's initial brief, p. 82. DTE Electric asserts that "the real issue impacting storm response has been, and continues to be, the volume of events that occur during a narrow window of time during large weather events." *Id*., pp. 82-83. The company asserts that equipment is still the leading cause of outages over the last five years and customers want to see significant reliability improvements, which can only be delivered by improvements to equipment. 3 Tr 410-412; DTE Electric's initial brief, pp. 83-84.

DTE Electric further argues that it provided a clear explanation as to why project rankings move around, including considerations such as whether the target document is forward-looking or not. 3 Tr 490-493; DTE Electric's reply brief, p. 25. DTE Electric notes the new dimensions added to the GPM for the 2023 DGP and argues that "comparisons between GPM outputs from previous rate cases and the current case are inappropriate because of changes to the GPM structure." *Id*., p. 26. The company asserts that MNSC's comparisons between programs from different years are based on speculation because of the programs' changes, including the significant improvements to the PTMM in recent years. *Id*. DTE Electric contends that a decrease in investment will result in a decrease to benefits, thus not necessarily improving BCA ratios. DTE Electric rejects the idea that its inputs are subjective, arguing that they are based on sound engineering analysis. The company states, with respect to PTMM, that the point of inspection is to identify poles that need remediation. DTE Electric acknowledges that the GPM does not account for variance between circuits, but adds that it has provided a circuit-level BCA for PTMM. *Id*., p. 28. DTE Electric states that it "intends to provide effectiveness [data] for PTMM and Distribution Automation programs as data is collected post-construction." *Id*., p. 29.

Turning to the RM, DTE Electric argues that the RM is just one component of its support for the six reliability programs/projects, and additional support comes from the capital summaries, testimony, and GPM. The company states that it "plans to update the analysis to use a full calendar year in the next iteration of the [RM], but the 10 months used in the current version is not a fatal flaw." *Id*. DTE Electric posits that adding the full calendar year will not appreciably change the results. DTE Electric concludes that "[t]he Company is open to reasonable suggestions to improve the accuracy of the model, and a more granular assumption on the types of events may be considered in the future. There is always a balance between increasing model complexity, and the value that increased complexity brings." *Id*., p. 30. Noting the CEOs' request for additional BCAs, DTE Electric argues that "BCA efforts are timely, costly, and may not make sense for all investment areas. The Company believes an order requiring BCAs for every investment area would be counter-productive and would instead encourage further engagement with interested parties to prioritize which BCAs would make the most sense." *Id*., p. 31.

In Case No. U-21297, objections to the GPM were presented by MNSC, the Attorney General, the CEOs, the DAAOs, MI-MAUI, and the Staff. December 1 order, pp. 56-62. In the December 1 order, the Commission found, in part, as follows:

> The Commission requires greater transparency into the basis for the GPM and the internal review process, as well as some explanation for the instances where the company deviated from the GPM's conclusions and sought funding for projects that were assigned a low priority. Without this additional information on how the rankings were arrived at, assessments of reasonableness and prudence are hampered and at times impossible. The Commission also expects DTE Electric to provide adequate supporting information, either in its initial rate case filing or in response to discovery, when intervenors seek basic information on the company's assertions about priority and need. Additionally, to the extent that either the GPM or the DGP offers a facsimile of a BCA, costs are not always addressed and benefits are not quantified. As DTE Electric is well aware, that does not constitute a BCA. . . . The company clearly put significant work into both the DGP and the GPM, but as long as the company's internal review process remains a black box the Commission's review and ability to evaluate the reasonableness and prudence of the project for which the company seeks recovery is likewise obstructed.

December 1 order, pp. 70-72. Additionally, in that order, the Commission noted the problematic nature of the decision to use "the GPM and the DGP as the sole sources of support offered by the company for so many capital expenditure programs, and, accordingly, emphasizes the importance of providing transparency to the selection process behind the GPM scores and supporting information to develop the DGP-based recommendations." December 1 order, pp. 84-85.

The Commission agrees with the CEOs that DTE Electric has introduced several new and useful analytical models on this record, and has relied somewhat less exclusively on the GPM as its sole source of support in certain cost categories. In the December 1 order, the Commission directed the company to provide greater transparency into the basis for the GPM and a better understanding of the deviations that occur. While MNSC makes several valid points, the Commission finds that DTE Electric has responded to that directive with additional information, and the internal review process is not the "black box" that it was in Case No. U-21297. The Commission also agrees with DTE Electric that requiring a full BCA for every investment category is not practical or advisable. The Commission sees progress in the company's efforts at transparency in this case and notes that DTE Electric has committed to adding additional actual performance data in the future rather than simply relying on subject matter experts, and to updating the RM to include full calendar year data. *See*, 3 Tr 445-448. DTE Electric has made clear its willingness "to continu[e] to work with CEO and other stakeholders if the Reliability Model methodology does not provide the information they are seeking." 3 Tr 445. The Commission does not expect the Top 50 list (or the associated cost estimates) to remain static. The Commission continues to adhere to the following observations from the December 1 order:

> As an initial matter, the Commission agrees with the ALJ that given the ever-growing 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.

December 1 order, pp. 70-71. Finally, the Commission acknowledges that the results of the audit performed in Case No. U-21305 are likely to impact certain aspects of DTE Electric's modeling efforts in the future, and the open-source BCA tool being developed in Case No. U-20898 will help simplify and streamline the ability to evaluate benefits and costs for many projects. The

Commission will continue to review the reasonableness and prudence of each expenditure request and the strength of the evidentiary basis for each request. At this time, the Commission does not find it necessary to direct the company to undertake broad changes to its modeling efforts.

h. Infrastructure Resilience and Hardening

DTE Electric explains that these projects and programs are focused on near-term investments in hardening the grid and addressing circuits with frequent outages. The company projects capital costs associated with these projects of $671.5 million for the bridge period and $364.7 million for the test year. 4 Tr 911; Exhibit A-12, Schedule B5.4, p. 13; Exhibit A-23, Schedule M5; DTE Electric's initial brief, p. 84. DTE Electric plans to invest in 16 different programs in this cost category. 4 Tr 912-1020. Specific disputed programs are discussed below.

i. 4.8kV Hardening

DTE Electric describes this as a program of near-term investments which addresses the removal of abandoned Detroit Public Lighting Department (DPLD) arc wire and the improvement of safety and reliability in Detroit, ahead of the longer-term 4.8kV circuit conversions. In addition to removing arc wire and distribution wire, this program includes "replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing service lines to abandoned properties, removing primary conductor in sparsely-populated areas (primary deconductoring), and trimming trees to support construction activities (Elliott Andahazy, 4T 913-14, 930-31)." DTE Electric's initial brief, p. 85. DTE Electric notes that the Commission has supported investments in this program in its last four rate cases. 4 Tr 917. The December 1 order, p. 93, directed the company to create a more comprehensive and longer-term plan for this program, that includes an equity and safety analysis. DTE Electric states that it performed an EJ/equity analysis of the 4.8kV hardening program using the MiEJScreen tool. DTE Electric's initial brief, p. 86. DTE Electric reports that the analysis "reflects that 85% of all 4.8kV Hardening Program investments from 2018-2025 impact communities that score in the top 80-100% MiEJScreen scores and are deemed vulnerable (Kryscynski, 3T 358; Elliott Andahazy, 4T 923)." *Id*.

The company states that it responded to the Commission's direction to proceed faster with arc wire removal by removing 208 miles in 2023, by planning the removal of 95 miles in 2024 (and the hardening of 145 circuit miles), and by planning the removal of 189 miles in 2025 (and the hardening of 310 circuit miles). *Id*. DTE Electric explains that there are fewer removed miles than hardened miles because the DPLD system does not perfectly overlap with the company's system, and, when hardening, the company hardens the entire circuit as there is a fixed cost for the work in any case. *Id*., n. 55; 4 Tr 923-925. Regarding the efficacy of the program, DTE Electric reports as follows:

> Circuits that were hardened experienced (1) a 38% reduction in All-Weather SAIFI vs. an increase of 23% in the control group (61% net improvement), (2) a 65% reduction in SAIDI ex-MEDs vs. a 3% reduction in the control group (62% net improvement), and (3) a 25% reduction in wire downs vs. an increase of 22% in the control group (47% net improvement). (Elliott Andahazy, 4T 927-30,1029-31).

DTE Electric's initial brief, p. 87. DTE Electric reports \$157.48 million in capital spending on hardening in the historical year, projects \$207 million for the bridge period, and projects \$125 million for the test year. Exhibit A-12, Schedule B5.4, p. 13.

MNSC argues that DTE Electric has overstated the benefits of the 4.8kV hardening program and the program should be slowed. 6 Tr 3993-3994; MNSC's initial brief, pp. 45-56. MNSC notes that in the November 18 order, pp. 192-193, the Commission directed the company to hold a technical conference, but Case No. U-21297 was filed prior to the date of the technical conference. Subsequently, based on the December 1 order, pp. 93-94, MNSC argues that DTE Electric reinvigorated the hardening program and proposed an investment plan but failed to present a plan to complete the arc wire removal. Exhibit A-12, Schedule B5.4, p. 13; 6 Tr 3993-3998; MNSC's initial brief, pp. 47-48. MNSC maintains that investments in arc wire removal should be increased and the ETTP should continue, but the other aspects of hardening should be halted. *Id*., p. 48. MNSC notes that wooden crossarms are being replaced with fiberglass crossarms irrespective of their condition. 4 Tr 913-914. MNSC states that their recommendation to proceed with arc wire removal in the test year at the pace that is proposed for hardening will reduce test year investments to $43.2 million, which is a 46% reduction in spending compared to the company's proposal for hardening. For the 2024 bridge period year, MNSC recommends maintaining spending at the level approved in the December 1 order of $6.7 million, which is a $73.3 million reduction. MNSC's initial brief, pp. 48-49.

MNSC contends that trimming alone, which is the first step in hardening, "has been shown to achieve significantly greater wire down reductions." *Id*., p. 49 (citing Exhibit MEC-4, p. 11). MNSC complains that the company has failed to evaluate the benefits of the non-trimming aspects of hardening. MNSC argues that simply removing the arc wire will provide most of the safety benefits at much less cost than the current program and with increased speed. 6 Tr 3994-3996. MNSC further argues that this program is redundant with the PTMM program because replacing crossarms where defects are identified is part of the PTMM work in any case, and that most of this hardening work will be rendered redundant when the conversion to 13.2kV occurs. 6 Tr 3995-3997. Since the cost of arc wire removal is 46% less than the cost of 4.8kV hardening, MNSC proposes total test year capital spending of $43.2 million for this effort which is a $81.8 reduction, and 2024 spending of $6.7 million which is a disallowance of $73.33 million for the bridge period. 6 Tr 3998; Exhibit MEC-72; MNSC's initial brief, pp. 49-52. MNSC states that the Commission "was clear in U-21297 that arc wire removal is the key benefit of Hardening, and it is proceeding too slowly. [MNSC's] recommendation to proceed with arc wire removal – while getting 4.8kV circuits on the ETTP cycle – is a more cost-effective way to remove arc wire than Hardening." *Id*., p. 54. MNSC argues that doing a BCA would not result in any delay to the effort, and, in light of the amount of data that is already available, would not be difficult. MNSC contends that the company has already invested nearly $500 million on hardening without a proper BCA, and a BCA should be provided before spending another $240 million in 2024-2026, whether or not the program is considered mature. Alternatively, MNSC argues, the Commission should approve half of the spending that is sought and direct it for arc wire removal only. *Id*., p. 55.

The Attorney General relies on MNSC's arguments. Attorney General's reply brief, p. 23. She contends that the AGMN witnesses Mr. Alvarez and Mr. Stephens have offered commonsense alternatives to DTE Electric's more expensive proposals to improve reliability, and she urges the Commission "to try a different approach – one that does not involve pouring more money into the system." *Id*.

The DAAOs agree with MNSC's observations about DTE Electric's reliability investments. They also note that BCAs provide important insights, but argue that BCAs will not resolve most capital expenditure issues, and they urge the Commission to focus on equitable solutions. 6 Tr 4444-4445.

DTE Electric counters that circuits in the 4.8kV hardening program are excluded from the PTMM program, and the two programs are coordinated such that these circuits will receive PTMM work on some future cycle. 4 Tr 1032-1033; DTE Electric's initial brief, p. 88. The company argues that the hardening program is coordinated with the 4.8kV conversion program so that circuits that are selected for near-term conversion are not hardened, and the circuits selected for hardening are not expected to see significant load growth. *Id*., p. 89. The company also contends that the equipment used for pole tops may be able to be retained when hardened circuits are converted to 13.2kV.

DTE Electric further counters that arc wire removal alone would provide 50% of the benefits at about 55% of the cost required for the hardening program. 4 Tr 1036-1037; DTE Electric's initial brief, p. 90. The company contends that this is a mature program which began in 2018 and will be completed in 2026, and for which DTE Electric provided actual performance data in the instant case and the two rate cases prior to this one showing clear benefits to customers. 4 Tr 927-1041; Exhibit A-51, Schedule PP9. The company maintains that the program should not be suspended in order to do a BCA. DTE Electric adds that it has not claimed that the program eliminates all risk but that it does reflect improvements. DTE Electric's initial brief, p. 87. The company further argues that it left out the trimmed circuits in order to show the benefits of the hardening versus doing nothing. DTE Electric indicates that this was the method used in the last two rate cases. But the company also argues that the data shows benefits even if the control group is not considered. *Id*., pp. 87-88; 4 Tr 1027-1031; Exhibit A-51, Schedule PP9. DTE Electric also counters that the Commission has directed the company to accelerate this work and such reductions will only result in delay. DTE Electric's initial brief, p. 92.

DTE Electric continues that "MNSC isolates the year of and year before circuit hardening to support its position. It is important to consider, however, the 2021 hardened circuits only have a limited sample of one-year of post-hardening performance data. Circuits with more after-hardening years (those completed in 2018, 2019, 2020) show more substantial non-tree related event reductions." DTE Electric's reply brief, p. 32; *see also*, pp. 33-34. The company contends that this data shows a reduction in the total duration of time that customers are without power.

Regarding MNSC's arguments supporting tree trimming alone with respect to wire downs, DTE Electric contends that the:

> ETTP analysis spans the Company's entire electrical system, includes data from 2012-2023, and is restricted to only wire downs associated with trees (Steudle, 6T 2967-2968). The 4.8kV Hardening Program before and after analysis provided in Company witness Elliott Andahazy's direct testimony more relevantly includes data from 2018-2023, all wire down events regardless of cause, and only considers 4.8kV circuits. The ETTP and 4.8kV Hardening analyses are simply not directly comparable as they include substantially different variables (e.g. geographical area, timeframe and types of wire downs included).

DTE Electric's reply brief, p. 35. The company also states that the tree trimming specifications for hardening are more comprehensive than the specifications for the ETTP.

The Commission approves DTE Electric's requested funding for the bridge period and test year. 4 Tr 913-916. The company held a technical conference for interested persons in March of 2023 which allowed for review of several of DTE Electric's analyses related to hardening and the 4.8kV system. 4 Tr 918-919. DTE Electric provided evidence showing its consideration of alternatives with quantified results and provided the EJ analysis as directed. 4 Tr 920-924. The company showed that 85% of 2018-2023 investments in hardening were spent in vulnerable communities, and 90% of planned 2024-2025 investments will be spent in vulnerable communities. 3 Tr 386-389; *see* 3 Tr 369-393. The company mapped its circuits to census tracts and cross-referenced those with the MiEJScreen tool. This is the type of information that has not historically been made available and is consistent with what the Commission was looking for. Progress has been made in terms of miles hardened and arc wire removed. 4 Tr 924. The Commission notes that 189 miles of arc wire remain to be addressed in 2025, 89 miles to be addressed in 2026, and there will be 253 miles remaining after 2026. 4 Tr 926. In its next electric rate case, DTE Electric is directed to present a comprehensive plan for the removal of the remaining 253 miles of arc wire.

The Commission is not persuaded to adopt the large disallowances proposed by MNSC. Beyond the primary safety issue, DTE Electric demonstrated the benefits that are accruing to customers as a result of both hardening and wire removal. 4 Tr 927-930. For example, all-weather SAIFI and SAIDI excluding MEDs have both improved in the wake of the hardening effort, as have wire downs. 4 Tr 928-930. While not a formal BCA, the Commission is satisfied with the level of quantification reflected in the company's evidence. Moreover, the Commission does not find that the company needs to show that the improved reliability metrics are solely due to the hardening effort in order to find value in this work. This program was never expected to eliminate the risk of all downed wires, but it is clearly addressing the risk associated with downed arc wire. 4 Tr 1033-1035. The company has also shown that the benefits of the hardening and tree trimming will not necessarily be lost when the conversion to 13.2kV takes place (such as retention of the crossarms); the program is not redundant with PTMM; and it doubles the number of circuit miles addressed for tree trimming, pole top inspection and replacement, and pole inspection and replacement. 4 Tr 1028-1044. For all of these reasons, the Commission approves the capital expenditures reported and projected by DTE Electric. As stated above, in its next rate case, DTE Electric is directed to present a comprehensive plan for the removal of the remaining 253 miles of arc wire.

ii. Pole and Pole Top Maintenance and Modernization

DTE Electric states that the PTMM is a pole and pole top inspection and replacement program for which the company has enhanced its requirements in recent years. 4 Tr 933-950; DTE Electric's initial brief, pp. 92-93. The company has approximately one million poles spread over about 31,000 miles, and poles have a useful life of about 40-50 years. 4 Tr 934. DTE Electric indicates that a 5-year inspection cycle is common practice in the Midwest for pole tops, and a

10-year cycle is common practice in the Midwest for poles; and the company notes that a 10-year cycle comports with a Staff report from 2009. 4 Tr 937; DTE Electric's initial brief, p. 93, n. 56. DTE Electric states that about 70% of its infrastructure is overhead, and "overhead-equipment related outages account for approximately 25% of all outages customers experience during all weather conditions, and over 30% of all outages customers experience excluding Major Event days (MEDs). (Elliott Andahazy, 4T 933-38, 948-50, 1076)." *Id.*, p. 93. DTE Electric notes that, while approving rate base treatment of $63.45 million per year in the December 1 order, the Commission directed the company to prepare an annual inspection report and complete a BCA for this program. *See*, December 1 order, p. 93. The company states that it has provided annual reports since 2010 and it completed a BCA in February 2024, which shows an overall average benefit-cost ratio (BCR) of 3.8, meaning that the benefits of the program are 3.8 times greater for customers than running all equipment to failure. 4 Tr 947-948; DTE Electric's initial brief, p. 94.

DTE Electric argues that the greatest cost driver is the increased number of defective poles and pole tops that have been identified. The company states that in 2022-2023, it increased defective pole replacements by over 2,900 poles per year and increased defective pole top equipment replacements by over 5,500 per year. *Id.*; 4 Tr 950. However, DTE Electric argues that the limited funding of $63.45 million that was approved in the December 1 order will not allow it to complete 2024 and 2025 inspections consistent with a 10-12 year cycle for poles. Thus, the company indicates that it will complete inspections consistent with available funding, based on a prioritization of circuits for those years. DTE Electric's initial brief, pp. 94-95; 4 Tr 953-957. This will allow it to target 750 circuit miles in 2024 and 1,100 circuit miles in 2025, but for 2025 (the test year) the company seeks cost recovery of $121 million through the IRM.

MNSC opposes the PTMM investment plan and recommend that test year spending on this program be capped at the level approved in the December 1 order of $63.45 million, which is a $57.55 million reduction. MNSC also recommend rejection of the proposed IRM investment altogether. 6 Tr 4015, 4029; Exhibit MEC-11; MNSC's initial brief, p. 58. MNSC argues that DTE Electric did not hire a consultant or perform a BCA until after it had already decided to increase its pole construction and maintenance standards. MNSC further contends that the BCA is flawed because the company does not have data on the number of outages that result from specific types of pole top equipment failures. 6 Tr 4011-4012; MNSC's initial brief, pp. 59-63. MNSC argues that "PTMM is having the ironic effect of significantly slowing the pole and pole top inspection cycle, not progressing DTE towards its aspiration cycles. Increasing PTMM condemnation rates led to a construction backlog of pole and pole top replacements, so DTE halted most inspections in 2023." *Id*., p. 59 (citation omitted). MNSC contends that the company should pause spending and come up with a better plan based on an adequate BCA, and that, in light of their low cost and high value, the plan should prioritize inspections.

MNSC complains that the BCA assumes benefits that are not verified, and that the BCA projects equipment failures based solely on the age of the equipment. MNSC argues that the company should gather data about the cause of equipment-classified outages. MNSC does not support the BCA's reliance on a proprietary national database of failure probability forecasts and finds the 'do nothing' scenario unreasonable because it runs all poles and pole equipment to failure despite knowing that DTE Electric has an obligation to inspect poles. *Id*., pp. 61-62. MNSC states that "PTMM preemptively replaces functional but obsolete equipment that has never been demonstrated to be at risk of failure or causing outages." *Id*., p. 63. Finally, MNSC argues that even this BCA shows that PTMM is not cost effective, stating that:

> [o]f the nearly 3,800 circuits in the BCA, PTMM was cost effective for only about 100 circuits in terms of avoided reactive costs (ratio >1), or less than 3% of circuits. Systemwide, PTMM is not cost-effective relative to avoided reactive costs. Per the BCA, PTMM is not a cost effective program based on benefits to the Company and ratepayers generally; it only becomes cost-effective for some circuits when customer avoided customer outage costs through 2063 are included.

Id. (citations omitted). MNSC also contends that this amount of investment is premature before the results of the systemwide distribution audit have been assessed and before ETTP is 100% on-cycle. MNSC argues that PTMM spending should be held to the 2023 level in the test year and should be rejected for inclusion in the IRM. *Id*., p. 64.

DTE Electric rebuts that it performed the BCA after it was directed to do so by the Commission, and that the BCA was performed by a reputable company that has done similar projects with 19 other utilities and maintains a proprietary database of asset failures. 4 Tr 1048, 1096; Confidential Exhibit A-51, Schedule PP10; DTE Electric's initial brief, p. 96. Addressing some of MNSC's complaints, DTE Electric argues that the PTMM BCA model accounts for interest, the return to shareholders, and income taxes. DTE Electric's initial brief, p. 97. The company notes that the BCA uses a 6.92% discount rate. 4 Tr 1051. DTE Electric notes that it provided the entire model in discovery (Exhibit A-51, Schedule PP10), which shows that it looked at 3,844 circuits. DTE Electric further counters that its enhanced tree trimming requirements are supported by benchmarking and industry practices, and its funding request is supported by the BCA. 4 Tr 939-940; DTE Electric's initial brief, p. 99. DTE Electric states that:

> 2,359 of the 2,890 circuits (or 81.6% of the circuits) which contain overhead assets in the PTMM BCA Model have a benefit-cost ratio of one or greater when considering both emergent reactive reductions and LBNL [Lawrence Berkeley National Laboratory] ICE [Interruption Cost Estimate] Calculator reliability benefits. The PTTM Program's purpose is to increase safety and reliability. It is unclear why AG-MN witness Stephens discounts these reliability benefits.

DTE Electric's reply brief, p. 37 (citing Confidential Exhibit A-51, Schedule PP10). The company notes that a ratio "of one or greater means the benefits are equal to or greater than the costs." DTE Electric's reply brief, p. 37, n. 30.

The Commission agrees with MNSC that the recent audit is likely to affect the analysis of this expenditure category in the company's next rate case, but finds that DTE Electric's test year projection should be approved. The BCA demonstrates that the PTMM produces positive results. DTE Electric reports that about half of its one million poles are more than 50 years old (and about 26,000 poles are more than 91 years old). 4 Tr 935. In the last six years, the company has performed three benchmarking studies on 15 peer utilities looking at PTMM practices, the most recent being in 2022. 4 Tr 936. DTE Electric aspires to implement a 5-year cycle for pole tops and a 10-year cycle for poles, which includes inspection and construction. The Commission supports these work activities. *See*, 4 Tr 939-946. The Commission also notes that the report required by the December 1 order, p. 96, was filed in Case No. U-21297 on July 26, 2024, at filing #U-21297-0654, and provides information on the metrics. The BCA looked at the value of the benefits of the PTMM over a 40-year study period (calculating the benefits on the basis of avoided costs), and found an overall benefit of 3.8. 4 Tr 947-948; Exhibit A-23, Schedule M13. In the company's next rate case, the Commission expects to see progress in DTE Electric's goal of reaching the 5- and 10-year cycles "utilizing the reliability tier model and BCA output, to select the optimal mix of circuits to improve customer reliability" to match the industry standards that the company has identified through its benchmarking efforts. 4 Tr 956. However, the Commission rejects the company's proposal to expand the IRM to include the PTMM program, which is discussed in Section VIII.A. of this order, below.

iii. System Cable Replacement and Underground Residential Distribution Replacement – Exhibit A-12, Schedule B.5.4, Page 13, Lines 14, 18, & 19

In discussing its System Cable Replacement and Underground Residential Distribution (URD) Replacement programs, DTE Electric describes system cable versus URD cable and the different purposes of each. The company states that "[s]ystem cable is used to transmit higher voltage electricity from substation to substation and to feed primary circuits, while URD cable is designed to provide lower voltage electricity directly to residential neighborhoods." 4 Tr 987-988.

The company states that system cable replacement "is an industry standard program to reduce system risk and support reliability." 4 Tr 988. The company describes the scope of its Cable Replacement program; states that this program was included in its prior rate cases in Case Nos. U-21297, U-20836, U-20561, and U-20162, with the company specifically recalling the Commission's support for investments for this program in Case No. U-21297; and states that eight miles of system cable were replaced in 2023, with 41.4 miles replaced over the last six years, and with approximately 10 miles of cable replacement planned for 2024 and 11 miles in 2025 (with capital investments of $15 million and $16.5 million, respectively). The company then describes customer benefits of the program in terms of reliability, stating that "[t]his program reduces overall risk to customers and the grid by proactively replacing cables before they fail, in order to ensure necessary redundancies for this critical part of the system as designed." 4 Tr 997.

As far as URD cable and its URD Replacement program, DTE Electric describes URD cable as being "a specific type of cable designed for underground residential use on the Company's secondary electric system," consisting of "small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or less frequently is installed inside conduit" and "typically looped so that there are two paths to feed customers in case one URD cable fails," since underground repairs can take significant amounts of time to locate and repair as compared to overhead infrastructure. 4 Tr 997. The company states that, per Mich Admin Code, R 460.512, all residential subdivisions built since January 1, 1971, are served with either pre-1985 URD cable or 1985/post-1985 URD cable, with nearly 11,000 total miles of URD cable on the company's system. DTE Electric further provides that from 2018 through 2023 there have been approximately 930 URD cable failures per year on average. 4 Tr 999-1000. The company describes the scope of its URD Replacement program; states that this program was included in its prior rate cases in Case Nos. U-20162, U-20561, U-20836, and U-21297, with the company specifically recalling the Commission's support for investments for this program in Case No. U-21297; and states that 75.3 miles of URD cable were replaced in 2023, with approximately 223 miles of URD cable replaced from 2018-2023. The company explains that Exhibit A-12, Schedule B5.4 reflects a planned investment of $0 in 2024 and 2025 because URD Replacement investments have been moved to Exhibit A-33, Schedule X1 as a result of the Commission's approval of the company's IRM in Case No. U-21297. And, as far as customer benefits for the URD Replacement program, DTE Electric states that:

> [t]he program will improve reliability by reducing the number of residential customer interruptions experienced by URD cable failures in the areas in which this program has completed work. This will also benefit customers by reducing the risk of multiple failures and long duration outages due to pre-existing open loops as described above [in testimony].

4 Tr 1005.

AGMN contends that customer benefits of the URD Replacement program do not exceed costs and that rider programs shift risk to ratepayers and thus asserts that, because the company has not provided a BCA to support the investments, the Commission should not approve inclusion of this program in the 2026 and 2027 IRM. 6 Tr 4026-4028; Exhibit A-33, Schedule X1, line 5; Attorney General's initial brief, p. 89; MNSC's initial brief, p. 65.

In rebuttal, DTE Electric asserts that AGMN's position neglects the Commission's decision in Case No. U-21297 and the fact that the company has performed three BCAs (on PTMM, Strategic Undergrounding, and Overhead to Underground Services) and is moving to perform more. DTE Electric's initial brief, p. 102 (citing December 1 order, p. 99). Moreover, per DTE Electric:

> System cable and URD cable replacement are prerequisite infrastructure investments, however, that are foundational for the continuity of electric service. The consequences of failure are also so great (with large scale prolonged outages and the possibility of extensive system damage beyond the breaker itself), that a run-to-failure approach is not acceptable. Therefore, the investments are reasonable and prudent, and witness Stephens' suggestion [on behalf of AGMN] of not including the URD investments in the IRM for 2026 and 2027 should be rejected[.]

DTE Electric's initial brief, p. 102 (citing 4 Tr 1062; Exhibit A-23, Schedule M13); *see also*, DTE Electric's reply brief, p. 38.[17]

MNSC contends that the company's rebuttal is non-responsive to testimony on its behalf and does not indicate whether or how cable age correlates to outage risk and that the company has not yet satisfied the Commission's directive in the December 1 order to demonstrate that this program is cost-effective. MNSC thus asserts that it is premature and inappropriate to include preemptive URD cable replacement in the 2026 and 2027 IRM proposal. MNSC's initial brief, pp. 65-66.

The Commission finds DTE Electric's requested capital expenditures for its System Cable

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[17] In briefing, MI-MAUI states that while it "believes cost-effectiveness was not demonstrated in the main case, if the [company's underground cable capital replacements] program is administered primarily as described in the rebuttal testimony, MI-MAUI withdraws its recommendation for a disallowance of the program costs." MI-MAUI's initial brief, p. 16 (citing 6 Tr 3162-3165, 4316-4319). Given that DTE Electric addresses this under Community Lighting in its initial brief and references its rebuttal testimony on this topic and that MI-MAUI does not indicate any concerns with the same in its reply brief, the Commission has no reason to believe that the company's rebuttal testimony is misleading or untrue and therefore considers MI-MAUI's disallowance recommendation on the company's URD replacement program to thus be withdrawn in this case. DTE Electric's initial brief, pp. 165-166.

Replacement and URD Replacement programs to be reasonable and prudent.[18] As stated by the company, system cable and URD cable replacement efforts benefit customers by prioritizing and proactively replacing cables and transformers to reduce the risk of failures and prolonged outages, thereby supporting continued reliability. 4 Tr 996-997, 1005; DTE Electric's initial brief, pp. 100-101.

The Commission's decision on IRM spending for the company's URD Replacement program for 2026 and 2027 is separately addressed below, in Part VIII, Section A of this order.

iv. Breaker Replacement – Exhibit A-12, Schedule B5.4, Page 13, Line 16

DTE Electric describes the purpose of breakers and reclosers as electrical switches that recognize and isolate interruptions on the network from the rest of the distribution system to help minimize equipment damage and to allow power to continue flowing to as many customers as possible while restoration is completed on damaged circuits. 4 Tr 1005. The company states that it has approximately 6,000 breakers on its system, with approximately 60% of them at an age beyond their life expectancy and with breakers in the replacement program having an obsolete design (typically utilizing insulation oil for fault extinguishing) and classified into four categories: distribution breakers, subtransmission breakers, H-breakers, and substation reclosers. In addition to replacing breakers, DTE Electric states that the program also:

> replaces relays and controls to make the equipment SCADA-ready. SCADA (supervisory control and data acquisition) utilization on equipment, will provide the

[18] Aside from overall modeling and in-service date arguments raised by MNSC, the CEOs, and ABATE, which are thoroughly addressed by the Commission above (in Part V, Sections B.4.d. and B.4.g. of this order), the Commission notes that no other party recommended a disallowance of capital expenditures for these programs (noting again the Commission's consideration that MI-MAUI's recommended disallowance has been withdrawn). The Commission also highlights again that the company included no forecasted capital expenditures for its URD Replacement program for 2024 or 2025 in this case, as a result of the approval of the IRM. 4 Tr 1004; Exhibit A-12, Schedule B.5.4, p. 13, lines 18 and 19; Exhibit A-33, Schedule X1.

> Electric System Operations Center (ESOC) greater visibility to system performance, which will allow ESOC personnel to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits during both planned and unplanned outages.

4 Tr 1006. The company states that this program was included in its prior rate cases in Case Nos. U-20162, U-20561, U-20836, and U-21297, with the company specifically recalling the Commission's support for investments for this program in Case No. U-21297, and describes customer benefits of the program as follows:

> The benefits of breaker replacement and enhanced relaying and controls include enhanced safety, reduction of substation outage risk caused by breaker failures, improved customer reliability, reduction in reactive expenditures due to breaker failures, added ability to utilize SCADA controls, and the reduction of outage duration due to enhanced fault location and event analysis provided by SCADA capability.

4 Tr 1007. The company further describes how breakers are selected for replacement, details the number of breakers replaced from 2018-2023, and explains that Exhibit A-12, Schedule B5.4 reflects a planned investment of $0 in 2024 and 2025 because Breaker Replacement investments have been moved to Exhibit A-33, Schedule X1 as a result of the Commission's approval of the company's IRM in Case No. U-21297. 4 Tr 1008-1010.

AGMN contends that customer benefits of the Breaker Replacement program do not exceed costs and that rider programs shift risk to ratepayers and thus asserts that, because the company has not provided a BCA to support the investments, the Commission should not approve inclusion of this program in the 2026 and 2027 IRM. 6 Tr 4026-4028; Exhibit A-33, Schedule X1, line 4; Attorney General's initial brief, p. 89; MNSC's initial brief, p. 65.

In rebuttal, DTE Electric asserts that AGMN's position neglects the Commission's decision in Case No. U-21297 and the fact that the company has performed three BCAs (on PTMM, Strategic Undergrounding, and Overhead to Underground Services) and is moving to perform more.

DTE Electric's initial brief, pp. 103-104 (citing December 1 order, p. 101). Moreover, per DTE Electric:

> Breaker replacement is a prerequisite infrastructure investment, however, that is foundational for the continuity of electric service. The consequences of failure are also so great (with large scale prolonged outages and the possibility of extensive system damage beyond the breaker itself), that a run-to-failure approach is not acceptable. Therefore, the investments are reasonable and prudent, and witness Stephens' suggestion [on behalf of AGMN] of not including the investments in the IRM for 2026 and 2027 should be rejected[.]

DTE Electric's initial brief, p. 104; *see also*, DTE Electric's reply brief, p. 39.

MNSC responds and contends that the company's rebuttal is non-responsive to testimony filed on its behalf and does not indicate whether or how breaker age correlates to outage risk and that the company has not yet satisfied the Commission's directive in the December 1 order to demonstrate that this program is cost-effective. MNSC thus asserts that it is premature and inappropriate to include preemptive breaker replacement in the 2026 and 2027 IRM proposal. MNSC's initial brief, pp. 65-66.

The Commission finds DTE Electric's requested capital expenditures for its Breaker Replacement program in this case to be reasonable and prudent.[19] As stated by the company, "[b]reaker replacement is a prerequisite infrastructure investment . . . that is foundational for the continuity of electric service," with benefits of the program specifically including "enhanced safety, reduction of substation outage risk caused by breaker failures, improved customer reliability, reduction in reactive expenditures due to breaker failures, added ability to utilize

[19] Aside from overall modeling and in-service date arguments raised by MNSC, the CEOs, and ABATE and completely and thoroughly addressed by the Commission above (in Part V, Sections B.4.d. and B.4.g. of this order), the Commission notes that no other party recommended a disallowance of capital expenditures for this program. The Commission also notes that the company included no forecasted capital expenditures for this program for 2024 or 2025 in this case, as a result of the approval of the IRM. 4 Tr 1010; Exhibit A-12, Schedule B.5.4, p. 13, line 16; Exhibit A-33, Schedule X1.

SCADA controls, and the reduction of outage duration due to enhanced fault location and event analysis provided by SCADA capability." DTE Electric's initial brief, p. 104; 4 Tr 1007.

The Commission's decision on IRM spending for this program for 2026 and 2027 is separately addressed below, in Part VIII, Section A of this order.

v. Other Programs – Exhibit A-12, Schedule B5.4, Page 13, Lines 2, 17, 20, 21, 22, 25, 28, 30, & 31

DTE Electric's other specific strategic capital investment programs include its Mobile Fleet program, Pontiac Vaults program, Automatic Pole-Top Switch program, Disconnect and Switcher Replacement program, Steel Pole Highway Crossings program, Batteries and Chargers Replacement program, SCADA Pole-Top Device Replacement program, Substation Regulator Replacement program, and Portable Generators program. 4 Tr 1010-1020; 6 Tr 3058. For its Portable Generators program, the company requests $4.5 million for the purchase of portable generators in 2024 to deploy to customers to provide temporary electricity during storms. 6 Tr 3058; Exhibit A-12, Schedule B5.4, Page 13, Line 28. For this program, DTE Electric states that it "will prioritize generators to customers based on the estimated duration of storm outage, customer medical needs, and other factors," with the portable generators to cover "items like refrigerators, freezers, personal medical devices, and sump pumps." 6 Tr 3058.

The Attorney General disputes the Portable Generators program, arguing that, although the program may seem appealing, "it is fraught with pitfalls." 6 Tr 3615. Specifically:

> The vulnerable customers that the Company aims to help need heat and air conditioning during periods of cold weather and hot days when the worst storms usually occur. The generators would not be able to help with either of those life-threatening needs. It is also not clear what those customers would do for the first two days until the generators are delivered. With tens of thousands of customers usually out of power for multiple days, the demand would overwhelm the small supply of generators, thus causing more customer ill will than appreciation. Gasoline delivery could be compromised if nearby gas stations also do not have power to operate their pumps.

> If the Company believes there is merit and corporate image building benefits to such an idea, it should fund it with shareholder money. It is unfair for customers who pay the Company for electricity service, which they are not getting during power outages, to on top of that pay for backup generators through rates, which also may provide them with no service.

6 Tr 3615. The Attorney General thus recommends that the Commission remove the $4.5 million from DTE Electric's forecasted capital expenditures for the company's Portable Generators program in 2024. Attorney General's initial brief, pp. 26-27; Attorney General's reply brief, p. 24.

DTE Electric disagrees, asserting that, notwithstanding the inability to provide heat and air conditioning, the generators will still provide several benefits to customers, including "powering medical devices for vulnerable customers, powering appliances to preserve food and allow food to be cooked (avoiding customer frustration in having to throw away and repurchase food), power sump pumps (to prevent home flooding), and enabling customers working from home to use their internet services and computer devices." DTE Electric's initial brief, p. 105 (citing 6 Tr 3084-3085). The company also clarifies an apparent misunderstanding about the deployment of generators—that the company will create a list of all customers likely to be without power for at least 48 hours and immediately contact those customers to offer them a generator, not wait 48 hours to do so. 6 Tr 3085; *see also*, Exhibit AG-58. The company further provides that it does not anticipate generator demand to exceed supply at this time but will monitor supply and demand, adapting accordingly to serve customers, and that the company has several options to ensure gasoline is available during power outage events, including utilizing gasoline from large underground tanks in its field service centers and deploying employees and contractors to areas where gas stations have power. 6 Tr 3085. DTE Electric thus avers that its capital expenditure request for this program should be approved as reasonable and prudent, as providing portable generators to vulnerable customers during storms "is an effective method for mitigating some of the impacts of power disruptions." 6 Tr 3086; *see also*, DTE Electric's initial brief, pp. 104-105, and DTE Electric's reply brief, pp. 39-40.

The Commission finds sufficient evidence on this record to allow cost recovery of this program in this case and supports the company's attention to customers who are particularly vulnerable to the detrimental effects of power outages. The Commission, however, underscores the need for DTE Electric's focus to be on avoiding power disruptions in the first place and highlights that the company's use of the terminology "vulnerable customer" in describing this program is independent of any Commission requirements or input. Notably, the Commission points to the Commission's Consumer Standards and Billing Practices for Electric and Natural Gas Service which contain definitions of "critical care customer" and "medical emergency" as a benchmark for compatible considerations for potentially vulnerable customers. *See*, Mich Admin Code, R 460.102(n) and R 460.102a(*i*). The Commission further cautions that the company-asserted "benefits" like power for computer devices for remote workers should not be conflated with the pressing needs of truly vulnerable customers during an outage.

i. Infrastructure Redesign and Modernization – Exhibit A-12, Schedule B5.4, Pages 14-16

DTE Electric states that its Infrastructure Redesign and Modernization projects and programs "fundamentally rebuild and upgrade the distribution and subtransmission segments of the grid" and "add capacity by converting the distribution system to a higher voltage for growing customer load, reduce outages and shorten outage restoration time by incorporating modern technology and equipment, harden the grid, improve redundancy and resiliency of the system, and increase safety." DTE Electric's initial brief, pp. 105-106; *see also*, 5 Tr 1136-1137, 1218. The company states that these projects and programs "fall into five primary areas: (1) Conversion Programs (City of Detroit Infrastructure (CODI)), 4.8 kV Conversion, 4.8 kV ISO [isolation down]

Conversion, and 8.3 kV Pontiac Conversion); (2) Subtransmission Redesign and Rebuild; (3) Strategic Undergrounding (SUG); (4) Primary Deconductoring; and (5) System Loading."[20] DTE Electric's initial brief, p. 106; *see also*, 5 Tr 1137-1139. Projected capital expenditures for these projects and programs in this case total $777.7 million ($259.2 million for the 12 months ending December 31, 2023; $291.5 million for the 12 months ending December 31, 2024; and $227.0 million for the projected test year). Exhibit A-12, Schedule B5.4, pp. 14-16 (listing projects); Exhibit A-23, Schedule M6.

Disputed projects and programs within this cost category are discussed below.

i. City of Detroit Infrastructure Conversion – Exhibit A-12, Schedule B5.4, Pages 14 & 16, Lines 28-36 & 79-82

DTE Electric states that its CODI Conversion program directly impacts the core Downtown, Midtown, and New Center areas of Detroit, with additional projects to improve system reliability and safety in extended areas including Eastern Market, Corktown, Woodbridge, Island View, and the West and East River Fronts. 5 Tr 1154-1155. The company describes the customer base within this area (residential, commercial, and industrial customers, including commercial and multi-tenant buildings, healthcare facilities, universities, shopping centers, and stadiums) and then describes the drivers of this program (primarily challenges as a result of aging equipment, additional load growth realized and projected into the future, and high failure rates for the company's 4.8 kV and 24 kV electrical infrastructure with the need to serve customers safely and reliably), along with challenges with implementing the program and unique drivers that support prioritizing the CODI program to be completed in the next decade. 5 Tr 1156-1162. The

[20] Per DTE Electric, there appears to be no dispute relative to Primary Deconductoring and System Loading in this case. DTE Electric's reply brief, p. 44.

company further describes the scope of the projects in the CODI program included in this case as follows:

> The CODI program converts and consolidates substations, the AC network, and associated overhead circuits. This program will construct two new 13.2 kV substations (Corktown and Island View), expand three existing 13.2 kV substations (Midtown, Alfred, and Cato), and decommission five 4.8 kV substations (Charlotte, Walker, Howard, Kent, and Gibson). This program also converts and consolidates the AC network system, as well as converting and consolidating the associated overhead circuits from 4.8 kV to 13.2 kV. The program also includes decommissioning the aged underground 4.8 kV and 24 kV cables in the CODI footprint as shown in Figure 3 [representing the CODI Scope Area]. Table 3 provides a high-level summary of the projects in the CODI program with additional details provided in Exhibit A-23 Schedule M6.

5 Tr 1164; *see also*, 5 Tr 1155, 1165. The company also recaps this program from Case No. U-21297, including the Commission's recognition of the importance of necessary work on aging infrastructure and corresponding approval of the company's proposed spending but with the Staff's proposed disallowances in that case. DTE Electric's initial brief, p. 107 (citing December 1 order, p. 111). Projected capital expenditures for this program are $98.5 million for the 12 months ending December 31, 2023; $99.7 million for the 12 months ending December 31, 2024; and $48.4 million in the projected test year. Exhibit A-12, Schedule B5.4, pp. 14 and 16, lines 28-36 and 79-82.

AGMN addresses the company's conversion programs all together, including the CODI Conversion program, expressing concerns with the company's plan for the conversions without a supporting BCA and all to be completed within 15 years, which AGMN asserts "is an unreasonable aspiration" considering the likely 50-year period it took DTE Electric to build all these circuits in the first place. 6 Tr 4000-4001. Per AGMN, "DTE should pause its proposed ramp-up and demonstrate both that its planned pace of conversions – given the cost and value to ratepayers – is justifiable." 6 Tr 4001. MNSC disputes the company's rationale for its conversion programs, arguing that "DTE's proffered justifications of reliability, safety, and capacity do not withstand close scrutiny." MNSC's initial brief, p. 80; *see also*, *id*., pp. 81-87. MNSC additionally argues that "DTE's evidence lacks transparency – with information that conflicts across different exhibits, incomplete reporting of costs, and numbers that vary significantly from case to case." *Id*., p. 80; *see also*, *id*., pp. 87-90. Per MNSC, however, its witness (on behalf of AGMN) "did not challenge the test-year conversions spending but opposed preapproval of the 2026 and 2027 IRM spending levels because DTE has failed to support the need for such a rapid pace and so many dollars," with MNSC further highlighting that "[e]ven DTE's own internal communications acknowledge that 'we're concerned about execution' when it comes to the spending levels for conversions." *Id*., p. 80 (quoting Exhibit MEC-26, p. 20). In this regard, AGMN's witness specifically recommends the following for the company's conversion programs overall:

> I recommend the Commission moderate post-test year conversions spending and require DTE to provide further support for the program and in particular for its proposed rate of conversions. Consistently, the Commission should reject the Company's proposal to extend conversion spending through the IRM in 2026 and 2027. To that end, the Commission should direct DTE to solicit an independent expert to assess the appropriate pace of conversions. To the extent DTE justifies the pace based on capacity increases, DTE must provide independent analysis showing its EV adoption forecasts are likely; that its assumptions about EV charging behavior (peak vs. off-peak) are accurate; and that adoption forecasts and charging behaviors are associated to geographies, substations, and circuits. DTE must demonstrate the rate impact associated with the pace of 4.8kV circuit conversion, and that the impact is appropriate based on ratepayer interests and the value received. I also recommend the Commission require DTE to establish and present in its next rate case metrics, such as dollars per circuit mile converted, to budget and monitor circuit conversion costs.
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> [As far as recommendations related to proposed conversion projects], the Commission should clarify and improve the regulatory review process for all large ($10 million or more) voltage conversion projects. DTE should provide robust, project-specific risk-informed cost-benefit analyses for these projects, including a

> thorough review of alternatives, before substantial capital ($1 million) is invested beyond the conceptual and design phase.
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> * * *
>
> I am not recommending disallowance in this program area in the bridge and test years because DTE's proposed test year spending is for conversions ($78.8 million) and is substantially lower than conversion spending in 2022, 2023, and 2024. However, DTE proposes that circuit conversions would comprise $430 million of IRM spending in 2026 and 2027. DTE's lack of justification for the scope of circuit conversion based on its preferred pace of conversions undermines the prudence of the IRM proposal. The Commission should reject DTE's proposal to include Conversions in the 2026 and 2027 IRM because the Company has [sic: has not] supported conversions as a value proposition for ratepayers. Now that DTE has several conversion projects in service, it should have ample data to demonstrate the full actual costs and benefits to ratepayers of voltage conversion projects.

6 Tr 4006-4008 (footnotes omitted) (citing Exhibit A-12, Schedule B5.4, p. 16, line 15; Exhibit A-33, Schedule X1, line 2); *see also*, Attorney General's initial brief, p. 88.

The DAAOs argue that DTE Electric's equity analysis of its infrastructure spending and reliability performance is flawed and contradicts the company's rationale supporting its CODI conversion expenditures. More specifically, the DAAOs state that the company discusses exclusive use of the MI EJScreen tool to identify areas with high concentrations of low-income, minority, and other vulnerable populations, despite the tool's limitations, along with new load projects in the CODI area, which shows that the company is not primarily concerned with improving service to vulnerable populations but is rather focusing on investments to serve new load and new residents. 6 Tr 4410-4412. Per the DAAOs, "[w]ithout accounting for variation within tracts and demographic changes, the MI EJScreen tool alone would allow the Company significant leeway to invest in communities that are not the most vulnerable while claiming to be directing sufficient investment to EJ communities," and "[c]ounting investments in rapidly gentrifying areas that are primarily designed to serve new load and new residents as investments in vulnerable communities does not support the Company's conclusion that it is supporting vulnerable communities." DAAOs' initial brief, pp. 50, 54. The DAAOs also address the higher-than-average reliability already present in the CODI area. 6 Tr 4414-4416; DAAOs' initial brief, p. 52. To address the inequity of this investment and to prevent the perpetuation of future inequities, the DAAOs thus request that the Commission "order DTE to conduct a regression analysis with demographics and reliability as variables and provide this analysis in future rate cases," to improve the company's approach to EJ, similar to that required by the December 1 order for the company's distribution plans; "review DTE's claims that the CODI program contributes to equity and reduce DTE's capital spending on the program to the extent possible until the Company provides a proper equity analysis;" and "require DTE to consider changes over time in demographics that contribute to the MI EJ Score when assessing the equity impact of long-term infrastructure investments." DAAOs' initial brief, p. 56; *see also*, DAAOs' reply brief, pp. 14-17.

DTE Electric disagrees with the DAAOs, asserting that the DAAOs' arguments are unjustified and mischaracterize information provided by the company in terms of reliability, uniqueness to the CODI area, and the need to rebuild and maintain the system prior to the exponential escalation of large-scale failures. 5 Tr 1236-1239; 6 Tr 4413-4416; DTE Electric's initial brief, pp. 108-109; DTE Electric's reply brief, p. 40. DTE Electric further asserts, in response to AGMN, that the company's "15-year conversion goal is a directional target and may change in timing and priority as specific grid needs evolve in different geographic areas and circuits," with the grid being rebuilt "at a pace required to support customer needs and affordability" and driven by "capacity needs, reliability improvements, and addressing aging and end of life infrastructure." 5 Tr 1226; *see also*, DTE Electric's initial brief, pp. 111-112. The company further disputes AGMN's claimed lack of reliability improvements for conversion, asserting such claims to be inaccurate; disagrees with AGMN's safety assessment, contending that "reducing the risk associated with potential energized downed wires of the 4.8 kV ungrounded delta circuits should be a major focus and justification for converting the 4.8 kV circuits;" generally agreeing with AGMN that conversions should be prioritized based on loading but "from a capacity standpoint where 4.8 kV substations are over firm, and where there are circuit overloads," and also considering safety and reliability; noting that investments in the grid are required to prepare for the anticipated increase in EV and DER adoption; asserting that the company has been transparent, addressing AGMN's misunderstanding about information provided by the company; arguing that a third-party assessment would be redundant to the audit in Case No. U-21305; and disagreeing with the recommendation to develop metrics since conversion projects are complex and a one-size-fits-all metric would thus have limited value. DTE Electric's initial brief, pp. 112-114 (citing 3 Tr 443-444; 5 Tr 1144, 1225-1234; 6 Tr 3934, 4001-4007; Exhibit A-23, Schedule M8, pp. 19-21). Per DTE Electric, "Mr. Stephens' criticisms and recommendations regarding the conversion programs lack any valid basis. The record further reflects that the conversion projects will improve safety and reliability for customers, and are otherwise reasonable and prudent, so cost recovery should be fully approved." DTE Electric's initial brief, p. 114.

The Staff recaps the company's rebuttal in response to the DAAOs' arguments and states that the "Staff supports the projected spending for nearly all of the strategic capital programs" and that "[t]he projected numbers are in line with the Company's current path to improve the reliability, resilience and safety of the electric system." Staff's initial brief, p. 196 (citing 5 Tr 1235, 6 Tr 4414).

MNSC responds to DTE Electric, maintaining its opposition to the company's increase in capital spending for conversions and replying to certain specific arguments in the company's initial brief. Specifically, MNSC argues that the company's claimed reliability improvements are not supported by any analysis, that there is no universal reliability improvement from converting (rather reliability benefits need to be shown on a project-level basis), that the company has provided no safety analysis or data to justify its 4.8 kV circuit conversions, that the company only offers generalities (mostly without citation) to support its claimed capacity justification for conversions, that the lack of transparency was addressed by MNSC in its initial brief, and that each project being unique (in terms of metrics) is exactly the point (that projects need to be evaluated and justified individually instead of trying to rush through $25 billion of conversions in 15 years based on broad and unsupported claims about safety, reliability, and capacity). MNSC's reply brief, pp. 14-16.

The Commission acknowledges and shares the DAAOs' prioritization of investment concerns and, in this regard, wants to also see prioritization of investments by the company in neighborhoods within the company's service territory moving forward, not just investments in business districts. DAAOs' initial brief, p. 56. The Commission recommends, as put forth by the DAAOs, that DTE Electric evaluate changing demographics over time using data consistent with the underlying data sets for the detailed regression analysis already required to investigate "customer demographics and reliability for vulnerable communities to be used in the company's distribution plan case" to help enable a complete understanding of equity outcomes, including along the lines of race and class. December 1 order, pp. 375-376. The Commission recognizes MI EJ Screen scores as the primary screening criteria in assessing EJ impacts associated with planned company investments. That said, however, the Commission finds that DTE Electric reasonably supported its conversion capital expenditures requested for the historical, bridge, and test years in this case, including those related to the company's CODI program.

As far as capital for conversion spending moving forward, the Commission notes the audit report for DTE Electric filed on September 23, 2024, in Case No. U-21305 and the September 26, 2024 order in that case wherein the Commission invited comments from interested persons on the audit report and responses to company questions from the Commission. Because the topic of conversions is one of the programs at the heart of DTE Electric's audit and because the Commission expects further direction on the company's overall conversion plans to result from the audit, responses, and comments in that docket, the Commission agrees with AGMN and finds it reasonable and prudent to refrain from deciding future actions on this topic in the instant case, instead deferring the appropriate path forward for conversions to be decided in Case No. U-21305 and future cases. The Commission also notes that its decision on IRM spending for conversions for 2026 and 2027 is separately addressed below, in Part VIII, Section A of this order.

ii. Other Conversion Programs – Exhibit A-12, Schedule B5.4, Page 15, Lines 37-56 & 83-91

DTE Electric's other conversion programs include its 4.8 kV Conversion program, its 4.8 kV ISO Conversion program, and its 8.3 kV Pontiac Conversion program. DTE Electric's initial brief, pp. 109-114.

DTE Electric describes the scope of its 4.8 kV conversion program as:

- Building new, higher voltage substations or in some cases expanding and upgrading existing 13.2 kV substations. This will improve the ability to connect new customers and allow for load growth for existing customers.
- Completing overhead pre-conversion work including rebuilding pole top equipment, replacing poles, wires, and transformers as needed, and installing neutral wire.
- Undergrounding of the overhead wires will also be evaluated for construction feasibility, customer acceptance, and cost effectiveness.
- Reconfiguring circuits and establishing new jumpering points will be completed to improve operability. Jumpering is used during outage circumstances and is the act of feeding a circuit that has become deenergized by connecting it to an adjacent circuit, thus restoring power to the customers on the deenergized circuit.

- Converting and transferring the load from the 4.8 kV substations to the 13.2 kV substations.
- Installing controls and automation in the substations and circuits to current design standards.
- Remove arc wire and Detroit Public Light Department primary from the Company's system, on applicable Detroit circuits.
- Decommissioning of aging 4.8 kV substations and associated subtransmission infrastructure.

5 Tr 1144-1145. The company further describes the benefits and the 4.8 kV Conversion projects included in this case. 5 Tr 1143-1144, 1146-1150; Exhibit A-23, Schedule M6.

DTE Electric describes the scope of its 4.8 kV ISO Conversion program to convert isolation down (ISO down) circuits as:

- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire.
- Rebuilding underground infrastructure as needed. Reconductoring overhead wires as needed based on new circuit configurations and existing wire size.
- Reconfiguring circuits and establishing new jumpering points.
- Installing controls and automation in the substations and circuits to our latest design standards
- Removing ISO down transformers.

5 Tr 1170-1171. The company further discusses the benefits and the prioritization of circuits for this program. 5 Tr 1171-1172.

DTE Electric next describes the drivers of its 8.3 kV Pontiac Conversion program and provides the following scope for this program:

> The 8.3 kV system is served by four substations: Bartlett, Paddock, Rapid Street, and Stockwell and their combined eighteen (18) distribution circuits. The plan to address the 8.3 kV system has been developed, starting with upgrading the system underground vaults, additional project detailed information is provided in exhibit A-23 Schedule M6 as well as Section 9.3.7 of Exhibit A-23 Schedule M8 DGP. The additional scope for converting the 8.3 kV system includes expanding the existing 13.2 kV Catalina and Wheeler substations to add capacity. Once the Catalina and Wheeler substation expansions are completed, the overhead and underground infrastructure from Bartlett, Paddock, Rapid Street, and Stockwell substations will be converted and transferred to new 13.2 kV circuits.

> Additionally, the 8.3 kV conversion program will decommission all four 8.3 kV substations in the Pontiac area. The removal of at-risk, outdated, and obsolete 8.3 kV equipment from the system will reduce emergent costs and improve response time for customer restoration.

5 Tr 1174. The company then discusses the 8.3 kV Pontiac Conversion projects included in this case, along with the benefits of the program. 5 Tr 1174-1175.

As detailed above, AGMN does not challenge test-year spending for conversions in this case but does oppose preapproval of the 2026 and 2027 IRM spending levels without sufficient evidence to support the need and associated significant cost for such a rapid pace of conversion and also provides recommendations related to conversions moving forward. 6 Tr 4006-4008; MNSC's initial brief, pp. 80, 90; Attorney General's initial brief, p. 88; *see also*, MNSC's reply brief, pp. 14-16.

As also indicated above, DTE Electric disputes AGMN's recommendations. DTE Electric's initial brief, pp. 109-114. The company also disagrees with MNSC's assertion (relative to MNSC's assertion that the company's proffered justifications of reliability, safety, and capacity do not withstand close scrutiny) that MNSC requested a list of actual Occupational Safety and Health Administration (OSHA)-reportable safety incidents associated with the 4.8 kV system but that the company claimed to not have that information. DTE Electric's reply brief, p. 41 (citing MNSC's initial brief, p. 83). Per DTE Electric, MNSC's comment:

> is not a fair representation of the Company's response and neglects that OSHA requirements do not align with the discussion here, as the discovery response explained:
>
>> The Company does not have the data in the format requested. In addition, the number of events is not relevant because they include, for example, injury resulting from automobiles or structures making contact with poles and/or lines, and other incidents that do not bear on the relative safety of the system, or whether fault was found to lay with the Company.

> The Company records injury incident data in the format required by the Michigan Occupational Safety and Health Administration, specifically Part 11 Recording and Reporting of Occupational Injuries and Illnesses. [Exhibit MEC-77, p 7.]

DTE Electric's reply brief, pp. 41-42 (alteration in original).

As already decided directly above (in addressing DTE Electric's conversion programs overall, including the company's CODI Conversion program), the Commission finds that DTE Electric also reasonably supported its other conversion program capital expenditures requested in this case. 5 Tr 1225-1234. The Commission further reiterates that the appropriate path to address questions related to capital spending for the company's conversion programs moving forward will be addressed in other cases including Case No. U-21305 by way of the audit, responses, and comments, and the Commission's decision on IRM spending for conversions for 2026 and 2027 is separately addressed below, in Part VIII, Section A of this order.

iii. Subtransmission Redesign and Rebuild – Exhibit A-12, Schedule B5.4, Pages 14-15, Lines 5-27 & 66-78

DTE Electric describes its subtransmission system as "an interconnected web that transmits higher transmission voltage across the service territory to stations that step down the voltage to distribution levels to serve customers." 5 Tr 1176. The company discusses challenges and issues associated with its subtransmission system (aging, storm-related resiliency challenges, increased load leading to loss of contingencies, and difficult-to-access areas), along with benefits of the Subtransmission Redesign and Rebuild projects (safety, reliability, operability, and increased capacity). 5 Tr 1180-1182. DTE Electric discusses the scope of this program as follows:

> The subtransmission redesign and rebuild program is focused on installing new station equipment, as well as rebuilding both the overhead and underground portions of the subtransmission system. The station work involves the installation of large new transformers, capacitor banks and associated equipment, which provides significant improvements to the system with additional redundancy and voltage support. The overhead work will be completed to updated, more resilient

> standards which include the replacement of aged wood poles with new steel poles, porcelain insulators with polymer clamp top insulators, and smaller and aging conductors with larger wires. The new stronger poles are able to withstand winds up to 90 mph resulting in a much more storm resilient system. The larger wire standard conductor delivers multiple benefits such as providing significantly more capacity on each circuit, reducing the magnitude of voltage drop over long distances on the system, and additionally providing approximately twice the strength of existing conductors to withstand contact with a tree limb during storms or other tree related events. Similar to overhead construction, the underground work consists of replacing at-risk or overloaded cable with new sections and rebuilding cable poles to new standards, supporting greater reliability for both the underground cables themselves, as well as preventing cable failure impacts to adjacent cables in the same underground section of the system.

5 Tr 1182-1183. The company then describes how the program was developed, prioritization of circuits for the program, and Subtransmission Redesign and Rebuild projects included in this case. 5 Tr 1183-1189; *see also*, DTE Electric's initial brief, pp. 114-115. For this program, DTE Electric includes $72 million in capital expenditures for 2023, $40.6 million in capital expenditures for 2024, and $43.6 million in capital expenditures for 2025, in addition to IRM amounts approved for 2025 from Case No. U-21297 ($53.8 million), and further requests IRM amounts of $55 million for 2026 and $65 million for 2027, which are addressed separately in this order. Exhibit A-12, Schedule B5.4, p. 16, line 114; *see also*, 2 Tr 119 and December 1 order, p. 291.

AGMN contends that the projects in this program "can be extremely costly" and argues that the company "provides slender evidence outlining the full timing, cost, and value of these projects, which typically extend over multiple years" and which then makes it "difficult to determine the full actual cost to ratepayers resulting from these projects, and even more so to ascertain their quantifiable benefits (or value) to ratepayers." 6 Tr 4017. MNSC further contends that subtransmission equipment outages do not justify such a large subtransmission investment overall (that since subtransmission service interruptions are such a small portion of the company's total service interruptions the merits of each project should instead be evaluated individually); that the company exaggerates the resilience benefit of its subtransmission program (in that benefits are only indirect as the company rebuilds circuits with larger conductor and steel poles and wind and ice only comprised 1.3% of subtransmission equipment outages from 2019 to 2023, the company failed to explain why tree trimming is not a more cost-effective strategy for tree-related subtransmission outages, and the company provided no support for the assumption that one-quarter of equipment failures should be considered storm-caused); that the company's planning criteria exaggerates the need for full redundancy on the subtransmission system (as the company's use of single contingency for full redundancy at peak load is unsupported by any industry reference and the vast majority of distribution substations have a back-up source of supply for most hours of the year, casting doubt as to whether an expensive upgrade is really necessary to cover the remaining hours without a BCA); and that the company provided only limited loading data, which then contradicted its own claims that the subtransmission projects are needed for capacity reasons. MNSC's initial brief, pp. 68-74; *see also*, 6 Tr 4015-4019. In this regard, MNSC thus recommends:

> Because DTE exaggerates capacity constraints on the subtransmission system, fails to support its capacity claims with loading data, and does no cost-benefit analysis, the Company has not demonstrated that these projects are reasonable and prudent investments. Mr. Stephens recommended that the Commission disallow cost recovery on the Subtransmission projects that it has not already approved. Those projects are Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509. All are coming online in 2024 and 2025 with total expenditures of $28.15 million [for capital expenditures from 2022-2025]. Mr. Stephens also recommended that the Commission disapprove DTE's request for pre-approval of the $120 million total Subtransmission spending under the IRM for 2026 and 2027. Finally, Mr. Stephens recommended that going forward, the Commission should require DTE to provide project-specific risk-informed cost-benefit and alternatives analyses for all Subtransmission projects over $10 million, before investing substantial capital beyond the conceptual and design phase.

MNSC's initial brief, p. 75 (footnotes omitted) (citing 6 Tr 4020-4021; Exhibit A-12, Schedule B5.4, p. 14, lines 14, 15, and 18; Exhibit A-33, Schedule X1); *see also*, Attorney General's initial brief, pp. 88-89, and MNSC's initial brief, p. 78 (for clarification that the December 1 order "did not include approval of expenditures for Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509").

DTE Electric disagrees with AGMN. The company asserts that AGMN neglects "that when a subtransmission outage does occur, a large number of customers do not have power, often for an extended period of time," thus demonstrating that it is critical to improve the reliability of the company's aged subtransmission system and address concerns to maintain redundancy. DTE Electric's initial brief, p. 116. The company further disputes that the current condition of its subtransmission system can just continue, as the company cannot simply continue to operate as-is indefinitely without any significant consequences to its customers (in terms of the system losing the ability to maintain the required redundancy to ensure grid reliability). *Id*. The company also reiterates that it performed an analysis that revealed approximately one-third of the circuit miles on its subtransmission system violated the company's planning criteria, which then leads to capacity limitations and the inability to add additional load without the risk of damage. DTE Electric further disagrees with AGMN that improved resiliency through the program is unnecessary, arguing that wind and ice are not the only causes of storm damage. Per DTE Electric:

> Approximately 30% of subtransmission outages are weather related. Also, although ice historically has occurred infrequently in the Company's service territory, when it happens it often results in large, catastrophic storm damage. For example, the ice event in 2023 dramatically impacted the Company's system, including subtransmission equipment. The Company has also been experiencing more frequent and increasing wind speed weather events. Thus, there is a need for a more durable and resilient subtransmission system (Kryscynski, 3T 314; Deol, 5T 1251-53).

DTE Electric's initial brief, p. 118 (footnote omitted). Further:

> Witness Stephens stated that "[t]he question is, on which subtransmission circuits are the risks the greatest, and how quickly should they be addressed?" (6T 4019). The answer is that the Company's subtransmission engineers prioritize projects to address thermal and/or voltage planning criteria violations based on the violation severity and customer impact. Witness Stephens was also inaccurate in suggesting that the Company does not consider alternatives. The Subtransmission Planning Engineers lead multiple technical reviews during the detailed engineering scope development phase to evaluate project options and the most cost-effective solution. These technical reviews include the evaluation of alternatives to the project (Deol, 5T 1185-86, 1253- 55; Exhibit A-50, Schedule OO3).

DTE Electric's initial brief, p. 118. Lastly, the company disagrees with AGMN's recommendation to disallow costs for the Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 projects, as these projects, per DTE Electric, are supported by Exhibit A-23, Schedule M6 (including project drivers, required scope, and associated benefits) and bridge period and test year amounts for these projects were approved by the Commission in the December 1 order. DTE Electric's initial brief, p. 119 (citing 5 Tr 1262); DTE Electric's reply brief, p. 42. Thus, per DTE Electric, "witness Stephens' proposed disallowance for the three projects should be rejected, and all Subtransmission Redesign and Rebuild projects should be approved through the projected test year, as well as included in the IRM for 2026 and 2027." DTE Electric's reply brief, p. 43.

MNSC responds, clarifying the Commission's decision in Case No. U-21297, highlighting that subtransmission outages do not translate into significant customer impacts in reality, reiterating arguments from its initial brief, and emphasizing the need for a BCA to determine whether an expensive upgrade is really necessary. MNSC's reply brief, pp. 17-20. Additionally, MNSC notes that DTE Electric provided limited loading data to support the claim that approximately one-third of the circuit miles on its subtransmission system violate the company's planning criteria, and the data that the company did provide showed the opposite: The data provided showed that the thermal planning criteria were not, in fact, violated in either scenario. MNSC's initial brief, pp. 67-78. In sum, per MNSC, "DTE did not support its large subtransmission expenditures with substantial evidence demonstrating they are reasonable, prudent, or cost-effective. Nothing in the Company's initial brief changes that conclusion." MNSC's reply brief, p. 20.

The Commission agrees with DTE Electric that the capital expenditures for the Tie 4105 or Trunk 3509 projects were approved in Case No. U-21297. In approving the 11-month bridge period and test year amounts in Case No. U-21297, the Commission adopted the administrative law judge's findings and conclusion on the issue, only after stating that the Commission does "not agree[ ] that the in-service dates are dispositive of the issue." December 1 order, p. 106 (citing PFD, pp. 274-275). Because the reason the judge recommended disallowance for Tie 4105 and Trunk 3509 was on the basis of the in-service dates being outside the test year, the Commission did not disallow these costs. However, considering the findings in the December 1 order, the evidence provided in this case, and the significant costs of the projects within this program, the Commission further agrees with AGMN's recommendation that, going forward, a greater level of detail and quantifiable support is needed from DTE Electric to support its subtransmission projects. One way to provide this level of support, as suggested by AGMN, is "project-specific risk-informed cost-benefit and alternatives analyses for all Subtransmission projects over $10 million, before investing substantial capital [$1 million] beyond the conceptual and design phase." MNSC's initial brief, p. 75; *see also*, 6 Tr 4020-4021. As noted above, many of these distribution-related investments are covered in the distribution audit in Case No. U-21305, and the Commission expects that the findings of that audit will inform future subtransmission investments. The Commission also notes the development of an open-source BCA tool is underway in Case No. U-20898.

The Commission's decision on IRM spending for Subtransmission Redesign and Rebuild projects for 2026 and 2027 is separately addressed later, in Part VIII, Section A of this order.

iv. Strategic Undergrounding Program – Exhibit A-12, Schedule B5.4, Page 15, Line 64

As a result of aged overhead infrastructure and increasingly frequent and severe storms impacting reliability, DTE Electric explains that it "is interested in making undergrounding a viable option when circuits are being converted as that is the optimum time to take advantage of the synergy of the rebuilding process instead of just replacing the existing overhead infrastructure." 5 Tr 1191. The company states:

> Undergrounding protects the electrical infrastructure from increased storm frequency and severity, thus providing resiliency and improving reliability. An undergrounded circuit also has safety advantages since there are no downed wires during storm events. Furthermore, over the life cycle of the assets, undergrounding can provide the benefit of reduced maintenance and repair costs due to eliminating the need for tree trimming, pole top maintenance, and in most storm cases, trouble response.
>
> Through benchmarking, the Company has learned that many other utilities are also pursuing undergrounding of their existing overhead lines as a means to harden their systems for greater resiliency, increase reliability, and improve storm response. To take advantage of this unique opportunity to be able to underground larger portions of the new converted system, the Company plans to conduct pilot projects, and initially seek out areas where there are construction synergies, which could be achieved by jointly working with municipalities or other utilities. This approach will allow the Company to learn, develop best processes for undergrounding in mature urban, suburban, and rural areas while focusing on reducing implementation cost. These pilot projects will also allow the Company to further demonstrate the benefits of undergrounding and determine when/where this design choice can be applied effectively.

5 Tr 1191-1192. DTE Electric recalls the Commission's request in Case No. U-20169 for the company to explore potential pilot projects to eliminate rear-lot overhead infrastructure and associated hazards and discusses its Appoline pilot, including the objectives of that pilot project, the timeline, lessons learned, BCA, and results. The company further discusses significant

benefits of safety and resiliency for customers that were not included in the financial benefit/cost ratio (BCR) of the Appoline pilot project as these benefits "are not easily quantifiable in a way that matches present day customer needs or impacts;" however, the company "will continue to collaborate with the [Commission] and [interested] industry [persons] to determine an appropriate way to quantify these benefits." 5 Tr 1198. DTE Electric then describes its other strategic undergrounding pilot project (Buffalo-Charles) as follows:

> By collaborating closely with the city of Detroit, the Company developed a project to underground portions of the STLUS DC116 circuit in the Buffalo-Charles neighborhood. This is a bold initiative to underground approximately four miles of residential distribution lines using front-lot construction in a mature urban neighborhood with the intent of capturing additional benefits of joint gas and electric work.

5 Tr 1198. The company then explains why it selected this neighborhood as its next underground pilot project, how customers and other interested persons were engaged in the inception of this project, the scope of this project, and timing for the project (indicating that the project "is expected to be completed by end of 2024"). 5 Tr 1201; *see also*, 5 Tr 1198-1201. The company indicates that it conducted a BCA for its Buffalo-Charles project using the same approach as that conducted for the Appoline pilot and describes the results of that analysis as follows:

> The BCR results for Buffalo-Charles were similar to Appoline in that it was lower than the overhead rebuild, but nearly equivalent to PTMM. As with the Appoline BCR, the Buffalo-Charles project BCR result was not unexpected, given that the Company is still in the early stage of undergrounding pilots. Several factors contributed to the lower Buffalo-Charles BCR. The analysis used an initial cost estimate for implementing front-lot underground infrastructure in a mature urban neighborhood while removing old rear-lot overhead construction. The Company believes that actual project costs may come in lower with rigorous project management and the realization of project efficiencies with greater pilot experience.

5 Tr 1201; *see also*, Exhibit A-23, Schedule M13. The company also explains that safety and reliability were again not included in the financial BCR for this project, similar to Appoline.

From there, the company compares the scope of its undergrounding pilots to other utilities that it benchmarked, explains why it chose to pilot undergrounding in dense urban environments, and discusses its consideration of additional underground pilot projects in the future. 5 Tr 1203-1204. In briefing, the company recaps testimony and also discusses the Commission's findings and conclusions on this issue from Case No. U-21297. DTE Electric's initial brief, pp. 120-123.

AGMN recommends that the Commission eliminate this program and disallow the company's requested expenditures for 2024 and 2025. Per AGMN, while replacing overhead lines in customer backyards with underground lines does offer some reliability and safety benefits:

> underground lines are subject to reliability risk from flooding and careless excavation, and subject to safety risk from both excavation and contact voltage. In short, undergrounding is not the panacea many perceive it to be. But most critically, undergrounding overhead lines and service drops is prohibitively expensive. The extreme costs of undergrounding must be considered in any discussion of the benefits. The Appoline pilot cost $14,672.13 per customer, while the Buffalo-Charles pilot cost $37,908.50 per customer. These costs per customer are typical in our experience, and the results of DTE's benefit-cost analysis ($0.58:$1 for the Appoline pilot and $0.37:$1 for Buffalo-Charles pilot) are in line with published research on the topic.

6 Tr 4025-4026 (footnotes omitted); *see also*, MNSC's initial brief, pp. 183-186, and Attorney General's initial brief, p. 89.

In testimony, the Staff expresses concerns with the alternatives considered by DTE Electric in the company's BCA, in terms of incompleteness and a failure to consider true alternatives in the analysis. Specifically, the Staff opines that:

> the PTMM alternative considered is incomplete and not considered a true alternative following Staff's review. The Commission has ordered BCAs be informed by the provisions of the National Standard Practice Manual (NSPM). The NSPM glossary defines a BCA as "a systematic approach for comparing the benefits and costs of alternative options to determine whether the benefits exceed the costs over the lifetime of the program or project under consideration." The PTMM and overhead rebuild alternative options compared to the overhead-to-underground conversion should be true, finished alternatives that evaluate total costs in the BCA. The PTMM program is similar to an operations and maintenance

> activity involving inspection and testing of equipment and, where necessary, replacement of failed equipment on the overhead distribution system that does not involve converting 4.8 kV circuits to 13.2 kV. In contrast, the Appoline and Buffalo-Charles overhead-to-underground projects involve the installation of new cable with 13.2 kV conversion capability. To illustrate further, assuming PTMM is selected as the preferred alternative to overhead-to underground conversion, if the inspections under the PTMM result in pole and pole-top replacements, the work will not completely make the circuits 13.2 kV capable. The remaining work necessary to convert the circuit to 13.2 kV leaves PTMM an "unfinished" alternative compared to the overhead-to-underground conversion with no consideration or methodology in the BCA to account for the additional work needed to make PTMM "finished" and prove an "apples-to apples" comparison. In addition to the PTMM work, further work will be needed to convert to 13.2 kV which, to Staff's understanding, is not being considered in the analysis. It is Staff's understanding that DTE's future goal is to convert all circuits to 13.2 kV, making comparisons to true, finished alternatives an important aspect of BCA to ensure alternative investment options are complete with all benefits and costs considered. One option could be to include the projected costs associated with converting from 4.8 kV to 13.2 kV in the future with the PTMM option. It is not clear how the Company has applied a comparable PTMM alternative to the overhead-to-underground conversions to achieve the status of weighing an option against a true alternative.

6 Tr 5037-5038 (footnotes omitted). The Staff, in this regard, "recommends the Commission order the Company [to] improve its BCA alternative analysis in future distribution plans and contested cases by applying comparable alternatives to prove true and complete alternatives have been considered." 6 Tr 5041; *see also*, Staff's initial brief, pp. 171-172, 174. Later in briefing, however, the Staff recounts the company's rebuttal to AGMN's arguments and states that the Staff "supports these pilots and believes that the knowledge that can come from the undergrounding pilots will be very valuable in making decisions regarding the reliability and safety of the electric distribution system in the future." Staff's initial brief, p. 195 (citing 5 Tr 1263, 6 Tr 4025).

Ann Arbor supports the pilots and the associated funding requested by DTE Electric, acknowledging the importance of exploring the feasibility of undergrounding, but asserts that the Commission should also require the company to conduct SUG pilot projects in communities outside of the City of Detroit and to provide a more transparent process for selecting communities for these pilots. Ann Arbor's initial brief, pp. 4, 19-20.

DTE Electric disagrees with AGMN. The company reiterates the impetus behind these pilot projects from Case No. U-20169 and indicates that it "remains interested in undergrounding because it offers a unique set of benefits to customers, including eliminating the safety risk associated with downed overhead equipment, reducing emergent reactive costs, and being the most resilient option for severe weather-related events." DTE Electric's initial brief, p. 123. The company further states that local governments have also indicated interest in undergrounding, pointing to Ann Arbor as an example. DTE Electric further states that "[i]t also bears emphasis that the Appoline and Buffalo-Charles projects are pilots from which the Company can develop processes and gain efficiencies so it can determine when and where this design option can be used most effectively." *Id*. The company also disputes AGMN's reliability and safety assertions, stating that:

> (1) underground cable and equipment are specifically designed to be able to withstand flooding, and (2) using 2023 all-weather data, completely undergrounded circuits had 77% better SADI [sic] performance than completely overhead circuits. Also, the risk from careless excavation is very low compared to the risk associated with a downed conductor.

Id. DTE Electric asserts that the Commission should approve its funding request for this program, noting the Staff's and Ann Arbor's support. DTE Electric's reply brief, p. 43. DTE Electric, however, disagrees with Ann Arbor's assertion that the company has not taken action on Ann Arbor's interest in undergrounding pilots within the city limits. Per DTE Electric:

> Company witness, Deol, addressed this claim, citing discussions initiated in October of 2023 with the City to incorporate undergrounding to accommodate a paving project. Witness Deol's rebuttal testimony also identifies Ann Arbor city officials with whom the Company has been actively meeting to explore a second infrastructure alignment opportunity. This alignment opportunity is pending

> engineering review for late 2024 and would allow undergrounding to take place in conjunction with city infrastructure work (Deol, 5T 1270).

DTE Electric's reply brief, pp. 43-44.

Ann Arbor responds to MNSC's position that undergrounding pilots produce insufficient benefit to justify continuation. Per Ann Arbor:

> as the Company indicated in its briefing, undergrounding has benefits beyond those that can be accounted for in a financial cost-benefit analysis, such as increased safety and resiliency, and the Company "is still in the early stage of undergrounding pilots." DTE's Initial Brief, p. 122. Ann Arbor supports funding for further undergrounding pilots to explore the potential benefits of undergrounding and to gain experience that may lead to more cost-effective undergrounding processes, with the caveat that DTE must implement a more transparent selection process for undergrounding pilot projects and make the opportunity to coordinate with a municipality and other utilities on planned work a criterion for selection, for the reasons discussed below.
>
> Ann Arbor appreciates intervenor concerns regarding the cost of undergrounding and believes these concerns could be mitigated through better coordination efforts.

Ann Arbor's reply brief, p. 7.

MNSC responds to the Staff, arguing that other utilities' undergrounding efforts without additional details does not show undergrounding to be cost-effective (in fact, the company's own analysis confirmed that it is not), customers and communities requesting a very expensive service does not make undergrounding reasonable and prudent (unless those customers and communities are willing to contribute resources to undergrounding to change the cost-effectiveness of a particular pilot), and the value of future learnings does not make the investment cost-effective. MNSC's reply brief, pp. 21-22.

The Commission continues to see value in undergrounding for targeted areas where undergrounding is shown to be the best option but continues to have significant and ongoing concerns over DTE Electric's support for its SUG pilots. The present record contains a number of significant deficiencies relating to the evaluation of benefits to support its undergrounding initiatives and the comparison between undergrounding and other potential alternatives. As such, the company's BCR for the pilots raises real questions on whether undergrounding is superior to the other alternatives presented on a quantitative basis, as the BCR for undergrounding both Appoline and Buffalo-Charles is less than the overhead rebuild option (and in the case of Buffalo-Charles even less than the PTMM option, notwithstanding the question of whether PTMM is even an appropriate comparison as argued by the Staff). Exhibit A-23, Schedule M13, pp. 23-24; 6 Tr 5037-5038. The Commission is further concerned that it requested "an accompanying *comprehensive* BCA" in Case No. U-21297 but that the company provided a BCA/BCR that "does not account for . . . [s]afety[,] . . . [r]esiliency for catastrophic events[,] . . . [and] [s]ize of the benefits," the latter of which the company says in terms of undergrounding "drives the highest reduction in emergent reactive cost, cyclical program cost [e.g., vegetation management] and customer outages when compared to other investment options." December 1 order, p. 103 (emphasis added); Exhibit A-23, Schedule M13, p. 23 (emphasis omitted); *see also*, Exhibit A-23, Schedule M13, p. 12 (for mention of vegetation management as an example of cyclical program costs). The Commission, moreover, finds that the current SUG costs per customer, as noted by MNSC, of $14,672.13 per customer for Appoline and $37,908.50 per customer for Buffalo-Charles, further reinforce the Commission's ongoing concerns over the value of the company's SUG pilots and whether the company's current approach to undergrounding could ever result in scaled deployment. 6 Tr 4025-4026, n. 76.

At the same time, the Commission notes that, even while recommending improvements to DTE Electric's BCA and alternatives analysis, the Staff "supports these pilots and believes that the knowledge that can come from the undergrounding pilots will be very valuable in making decisions regarding the reliability and safety of the electric distribution system in the future."

Staff's initial brief, p. 195 (citing 5 Tr 1263, 6 Tr 4025). Indeed, the Staff's concerns with the company's alternatives are largely focused on the fact that the limitations of potential alternatives (PTMM) were not fully incorporated into the analysis, leaving "PTMM an 'unfinished' alternative compared to the overhead-to-underground conversion with no consideration or methodology in the BCA to account for the additional work needed to make PTMM 'finished' and prove an 'apples-to-apples' comparison." 6 Tr 5038. In addition to the Staff's concerns over not fully considering the costs and limitations of potential alternatives, Ann Arbor echoes the company's testimony that the full range of benefits of undergrounding was also not considered in the analysis, arguing that "undergrounding has benefits beyond those that can be accounted for in a financial cost-benefit analysis, such as increased safety and resiliency," and as such "Ann Arbor supports funding for further undergrounding pilots to explore the potential benefits of undergrounding and to gain experience that may lead to more cost-effective undergrounding processes." Ann Arbor's reply brief, p. 7. On this basis, even while maintaining its concerns over the quality of the company's BCA and consideration of alternatives, the Commission finds that the company's capital expenditures during the bridge period were reasonable and should be recovered, and so declines to adopt AGMN's proposed disallowance for that period.

However, given these same ongoing concerns and considering DTE Electric's insufficient response to the Commission's decision and direction in Case No. U-21297, the Commission finds it appropriate to disallow the company's projected capital expenditures for the test year. Prior to continuing to expend capital for pilots with an incomplete BCA, an incomplete documentation of benefits, an incomplete accounting of the costs of alternatives, and an incomplete framework for how to scale pilots that are inherently costly when measured on a cost-per-customer basis, the Commission strongly encourages the company to better develop the business case for undergrounding—both at the pilot phase and for scaled deployment—and to continue to develop processes, gain efficiencies, and find synergies where possible to lower costs and to incorporate updated costs and better quantified benefits into its BCA/BCR to support future cost recovery, considering projects on a full-scale basis. As noted in the December 1 order, because "[u]ndergrounding is such an expensive proposition for ratepayers," a comprehensive BCA is needed "*before that expenditure is undertaken*" to demonstrate that undergrounding at scale has the potential to be "*superior to other alternatives on a quantitative basis*." December 1 order, p. 104 (emphasis added). The Commission, in this regard, looks forward to future updates on the company's progress in collaborating with the Staff and other interested persons in determining an appropriate way to quantify the significant benefits of safety and resiliency for purposes of future BCAs/BCRs. 5 Tr 1198. The Commission also references Case No. U-20898, for DTE Electric to monitor the docket on BCA development to ensure consistency with future open-source tool application and the Commission's approach to BCA framing and guidelines, along with Case No. U-21305 for any audit outcomes that may impact the company's undergrounding strategy and cost recovery requests moving forward.

j. Technology and Automation – Exhibit A-12, Schedule B5.4, Pages 17-18

DTE Electric states that the category of Technology and Automation consists of Grid Automation and Operational Technology (OT), with Grid Automation focusing on physical technology infrastructure needed to support the efficient control and operation of a modern distribution grid and with OT being a set of enabling technologies that interact closely with, and tailored to support the objectives of, Grid Automation. Grid Automation covers four key areas: (1) Distribution Automation, (2) Grid Automation Telecommunications, (3) Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO), and (4) Non-Wires Alternative (NWA) pilots.

OT covers five key areas: (1) Grid Management, (2) Distribution Planning, (3) Work Management and Scheduling, (4) Asset Management, and (5) Mobile Technology. DTE Electric's initial brief, pp. 126-127.

Disputed issues within these areas are addressed below.

i. Distribution Automation – Exhibit A-12, Schedule B5.4, Page 17, Line 2

As described by DTE Electric:

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

4 Tr 637 (footnote omitted). The company states that its DA program is primarily composed of pole top recloser deployments to isolate outages into smaller sections and reroute power around damage. 4 Tr 638. The company describes the scope for DA as including:

> (a) installation of SCADA enabled reclosers on larger circuits with more than 400 customers to have at a minimum of one midline recloser and a SCADA enabled tie point, (b) installation of a recloser near the start of the overhead portion of a circuit for all ungrounded 4.8 kV circuits to enable ground detection and isolation, (c) installation of reclosers near the start of the circuit on 13.2 kV circuits that currently do not have SCADA enabled circuit breakers in the substation, (d) the construction of the necessary overhead equipment to create and enable load shifts between circuits, and, (e) the integration of devices and technology within ADMS [advanced distribution management system] to allow for the application of FLISR [fault location, isolation, and service restoration] with the new and existing devices. The scope will also include ground fault detection and isolation on the 4.8 kV system, SCADA monitoring and control of all general-purpose distribution circuits, and improved fault isolation and increased remote restoration capabilities to improve reliability.

4 Tr 642-643. DTE Electric further describes how its strategy for this program has evolved since Case No. U-21297, explaining that the company determined that an expanded focus was necessary

to improve reliability performance (i.e., extensive circuit automation over the entire distribution grid). 4 Tr 643-644. From there, the company discusses its plan for a single focused DA program, how circuit level benefits are estimated, the scope and benefits of its DA Plan for 2024 and 2025, and progress made in DA in 2023. 4 Tr 644-647. DTE Electric's projected capital expenditures for this program are $27.1 million for 2023, $21.2 million for 2024, and $125.6 million for the projected test year. Exhibit A-12, Schedule B5.4, Page 17, Line 2; *see also*, DTE Electric's initial brief, pp. 127-128.

AGMN supports the company's efforts to develop a cost-benefit model and the company's initial roll-out of the new reclosers but opposes the planned rapid investment ramp-up in 2025 and then continuing into the IRM years. 6 Tr 4021-4023. AGMN details its concerns with the cost-effectiveness of reclosers when new tie lines are required (given the construction costs of new tie lines) and notes that the company already has programs to reduce wire-downs on 4.8 kV circuits, including ETTP, Hardening, DLPD removal, and PTMM. 6 Tr 4021-4023. AGMN thus provide the following three recommendations related to this program: (1) for the Commission to require DTE Electric to develop a benefit-cost model (as opposed to a prioritization model) to govern DA deployment on a circuit-specific basis (as safety benefits without supporting analysis is insufficient), (2) for the DA deployment budget to be limited to the annual amount approved in Case No. U-21297 ($27.167 million less a 10% reduction recommended by the Staff in that case (i.e., $24.5 million))[21] until a circuit-specific DA model can be developed (to ensure cost-effectiveness), and (3) for the Commission to reject the company's request to include DA spending in the proposed extended and expanded IRM (due to variations in cost-effectiveness by

[21] *See*, December 1 order, p. 123.

circuit and other limitations). 6 Tr 4024-4025; Attorney General's initial brief, p. 89; MNSC's initial brief, p. 92.[22] In MNSC's initial brief, MNSC describes this program as "the costliest of all DTE's proposed distribution system investments in the [company's distribution plan]." MNSC's initial brief, p. 91 (citing Exhibit A-23, Schedule M8, pp. 162-164). MNSC further argues:

> While details are scant, it is worth noting that $20 million of the planned $150 million investment in Distribution Automation in 2025 appeared to materialize through a text exchange between an unidentified DTE staff person and Ed Karpiel in the process of developing the [Case No.] U-21534 rate case proposal. It's unclear if this is a typical practice to develop rate case spending proposals at DTE.

MNSC's initial brief, p. 91. (footnotes omitted) (citing 2 Tr 216-218; Exhibit MEC-26, pp. 49, 50).

The Staff recommends no adjustments to the company's technology and automation expenditures at this time. 6 Tr 5157; Staff's initial brief, p. 193.

DTE Electric disagrees with AGMN, maintaining the reliability and safety benefits of DA, along with the company's support for the program and its DA prioritization tool. The company further asserts that the timing is now right considering advancements in relays, that investments in reclosers today will be able to continue to be used when circuits are converted from 4.8kV to 13.2kV, that the G&W Viper reclosers are an industry-proven and reliable device, that overbuilding concerns are misplaced, that the company does not plan on building tie points on every circuit, and that DA has been proven to be an effective reliability-improvement strategy.

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[22] The Commission notes that MNSC's figures on page 91 of its initial brief transpose the IRM approved amounts for this program from Case No. U-21297. As set forth on page 291 of the December 1 order, the Commission approved $26.406 million in automation capital expenditures for Plan Year 1 of the IRM ending December 31, 2024, and $24.375 million in automation capital expenditures for Plan Year 2 of the IRM ending December 31, 2025.

4 Tr 825-837; DTE Electric's initial brief, pp. 129-132. DTE Electric also disputes AGMN's recommendation to limit the company's DA budget. Per DTE Electric:

> the Company's planned Distribution Automation investments provide proven and compelling safety and reliability benefits to customers, and the Company's Distribution Automation Prioritization tool appropriately prioritizes circuits based on benefits per dollar. The prioritized investment in this case is also a "no-regret" investment that the Company should pursue aggressively because we are in an early stage of the automation journey that will take many years to implement (Hartwick, 4T 837).

DTE Electric's initial brief, p. 132. The company thus asserts that it has demonstrated that its investments in DA provide benefits to customers, are otherwise reasonable and prudent, and should be approved, with all contrary and additional proposals rejected. *Id*.; *see also*, DTE Electric's reply brief, pp. 45-47.

MNSC responds, arguing that the company's rebuttal is not responsive to testimony on behalf of AGMN and largely just reiterates the company's initial testimony. MNSC argues that the company's rebuttal "simply confirms that it is premature to approve the spending ramp-up until after there is historic data to evaluate whether projected wire down reductions in fact materialized," that "[t]he Company asks the Commission to place a nearly $400 million bet on Vipers and the credibility of its DA Prioritization model" without first demonstrating benefits, and that the company's reliance on the 2016 DOE report does not actually support the company's model but rather "concludes with some key lessons and conclusions that are more instructive than the uncited contextless outage blurbs in the call-out boxes [relied on and quoted by the company]"—"unequivocally [stating] that reliability benefits and cost-effective[ness] of FLISR and reclosers are utility-specific," thus supporting "slowing down the Viper deployment plan to assess its benefits based on DTE's experience with Vipers." MNSC's initial brief, pp. 93-97. MNSC concludes:

> The Company resists the recommendation to develop a circuit-specific benefit-cost analysis to support Distribution Automation on the basis it already has the DA Prioritization model, but prioritizing which circuits should be upgraded first does not demonstrate that installing reclosers on any circuit is cost-effective. The Distribution Automation program is still in its infancy and lacks historical data to support the reasonableness and prudence of massively increasing test year and IRM year investments. Additional programs underway offer reliability and safety benefits, particularly on 4.8V [sic] circuits, making it premature to approve increasing spending on Distribution Automation in this proceed [sic]. Moreover, the distribution audit warrants assessment before committing to such a costly and yet-unproven program for DTE. The Commission should maintain the level of spending approved in [Case No.] U-21297 ($24.449 million), which is nearly triple spending in historical year 2022.
>
> One final point about Distribution Automation bears mention, which further supports imposing a spending pause now. According to DTE, its plan to install thousands of reclosers through the Distribution Automation program is in turn driving the Company's $100+ million Grid Automation Telecommunication investment. DTE asserts that much of its pole top and other equipment is not yet adequately connected for communications, so the Company needs to upgrade the communications network then connect it to equipment. As discussed below, the Commission found DTE's plan to address communications gaps – i.e., a privately owned fiber network – insufficiently supported in [Case No.] U-21297 and disallowed 2024 spending, though the Company spent the planned investment anyway. As discussed below, the presentation in this case remains indeterminate and deficient. Two conclusions can be drawn here. First, it seems DTE does not have infrastructure in place to support Distribution Automation deployment, particularly at the audacious scale it is proposing. That supports a delay in Viper deployment. It also renders even more speculative its claims about the performance and projected benefits of Vipers on its system. The Commission should pause spending on both Distribution Automation and Grid Automation Telecommunications until DTE has developed a comprehensive assessment of the full costs and a realistic assessment of benefits to facilitate evaluation of whether the investment is worth the benefits, particularly in light of other ongoing investments (ETTP, Hardening, PTTM) [and] those on the horizon – i.e., potential 4.8 kV conversion.

MNSC's initial brief, pp. 98-99 (footnotes omitted).

Aside from the $20 million addressed during cross-examination that should thus be disallowed as seemingly unsupported, the Commission finds DTE Electric's remaining DA capital expenditures requested in this case to be reasonable and prudent. 2 Tr 216-218; Exhibit MEC-26, p. 49. More specifically, the Commission finds persuasive the company's rebuttal testimony,

particularly rebuttal testimony in terms of the significant benefits of DA (i.e., offering measurable safety benefits, notably in terms of ground detection to detect and isolate grounds mitigating potential safety hazards; improving reliability; and shortening the duration of outages).
8 Tr 825-837. The Commission also notes that the company is working toward a BCA for DA moving forward and looks forward to these results but finds the existing support on the record sufficient to approve all but $20 million. 4 Tr 837.

The Commission's decision on IRM spending for DA for 2026 and 2027 is separately addressed later in Part VIII, Section A of this order.

ii. Grid Automation Telecommunications – Exhibit A-12, Schedule B5.4, Page 17, Line 6

DTE Electric describes Grid Automation Telecommunications as:

> refer[ring] to the use of telecommunications technology 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. The telecommunications network is the backbone system that connects the distribution automation equipment in the field to the ESOC, enabling two-way remote monitoring and control that provides visibility into grid conditions and allowing the ESOC to remotely operate grid devices. An advanced telecommunications infrastructure plays a crucial role in grid automation by providing reliable and secure communication channels for data exchange between various grid devices such as sensors, meters, switches, and control centers. Telecommunication networks have always played an important role in supporting the safe and reliable delivery of electric power. This role is becoming even more crucial in the looming industry transformation, since Smart Grid represents the convergence of telecommunications, computing, and energy technologies.

4 Tr 647-648. The company describes the structure of a utility telecommunications network, discussing key elements including the backhaul network (being the focus of the company's Grid Automation Telecommunications investments in 2025) and the last mile network (in which the company plans to significantly invest in the future), and states that the grid telecommunications network consists of:

> many technologies such as fiber, wireless systems, elevated structures, switches, and routers. Each of these technologies need supporting investment to create an integrated system that allows for the seamless flow of information, enabling remote monitoring and control of the grid and is the mechanism that [sic: through which] cybersecurity threat monitoring and security updates are performed.

4 Tr 649. The company describes the existing state of its Grid Automation Telecommunications network, discussing current deficiencies that need to be addressed, along with "[t]he increasing deployment and utilization of grid automation equipment, evolving grid demands, and aging telecommunications infrastructure" as the other key drivers of its investment in Grid Automation Telecommunications. 4 Tr 651. DTE Electric details its investment plan for Grid Automation Telecommunications, how customers will benefit from the investment, and what telecommunication options were considered in choosing the best technology investment to support the Grid Automation Telecommunications backhaul network expansion and why the company ultimately chose private fiber for this portion of the project (for its unmatched bandwidth, speed, reliability, security, suitability for backhaul of other networks, and resilience to interference). 4 Tr 652-668, 669-671. The company then discusses this investment from Case Nos. U-20836 and U-21297, including the Commission's findings in those cases; how the company is controlling its investment costs for this program; and the company's investment plans past 2025 and into 2028. 4 Tr 672-674. The company states that, in this case, its Grid Automation Telecommunications investments beyond prior rate case approvals are $2.3 million for the 11 months ending November 30, 2023,[23] $1.6 million for December 2023, $16.9 million for 2024, and $15 million for 2025. 4 Tr 840; Exhibit A-12, Schedule B5.4, Page 17, Line 6; *see also*, DTE Electric's initial brief, pp. 132-134.

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[23] In Case No. U-21297, $17.5 million was approved for the 11 months ending November 30, 2023. 4 Tr 840.

AGMN dispute the investment and contend that the Commission should reject the company's fiber-optic data communications cable deployment plan, ultimately disallowing spending in 2024 and 2025,[24] without being able to review the company's entire Telecommunications Plan, and require the company to present, in its next rate case, a make versus buy analysis of alternatives and a tool to identify appropriate alternatives, should the company propose further spending on its Grid Automation Telecommunications program. Attorney General's initial brief, p. 86; 6 Tr 3972-3978, 3979-3980. AGMN, in this vein, dispute the need for real-time communications and that company-owned options are the best option and contend that the company did not complete the type of analysis requested by the Commission in Case No. U-21297. AGMN argues that:

> [b]efore making an investment of $100 million or more [from 2022-2028], an unregulated business would undertake a comprehensive "make vs. buy" study. Such a study would compare the pros and cons of each technology on technical, operational, cybersecurity, reliability, and other characteristics, and compare these pros and cons to the risks associated with each technology (generally, the size of the up-front investment) and the cost of each technology – not just initially, but over the lifetimes of each alternative's operation. An unregulated business might even employ outside experts to complete such a study to ensure objectivity. DTE has not completed such a study.
>
> Assessments of the characteristics of various alternatives should also be supported by data. For example, it would not be enough for DTE to claim that a public carrier's service is insufficiently reliable; DTE must identify the frequency with which commands issued over DTE's owned network failed compared to the frequency at which commands issued through the public carrier's network failed. Assuming the public carrier's performance was worse than the Company's (which should not be assumed), DTE should provide the consequence of the difference to customers. For example, of the increased failure rate observed (hypothetically) in commands issued over a public carrier network, how many resulted in service interruptions to customers, and what were the consequences to customers (in dollars) of these service interruptions? A precise quantification of

[24] In testimony, AGMN recommends that the Commission disallow costs incurred in 2022 and remove plan spending from the 2023-2024 bridge period and 2025 test year but also recommends, through another witness, disallowance only for 2024 and 2025 planned spending. 6 Tr 3978, 4029. In briefing, MNSC clarifies that, while 2022 and 2023 spending was unreasonable, given the decision in Case No. U-21297, only disallowances for 2024 and 2025 are being recommended. MNSC's initial brief, p. 102; Exhibit MEC-11.

> Telecommunication Plan benefits in dollars is needed for comparison to the incremental costs of the Plan.
>
> With an objective understanding of the pros and cons of each alternative relative to cost and risk, the next step would be to develop a tool to identify which alternative communications solutions are the most appropriate for application in certain situations and circumstances. The tool would use defined criteria, informed by the rigorous analyses described above, to help optimize communications technology choices for various situations' circumstances. DTE has not developed such a tool, and clearly does not possess the data needed to inform the development of such a tool.
>
> In short, DTE must provide evidence of data-driven decision-making of the sort described earlier in this testimony, and as described by Mr. Stephens in his testimony. If the Commission does not establish such expectations for the supporting analysis now, then DTE will continue to make unsupported proposals for telecommunications network capital spending in the future.

6 Tr 3976-3977 (footnotes omitted) (citing Exhibits MEC-8 and MEC-9). Per MNSC, "Grid Automation Telecommunications has the hallmarks of a program – a continuing annual investment" and thus the Commission should hold the company to the December order and disallow 2024 and 2025 spending as "[t]he Company accepted the risk of proceeding with 2024 spending without a robust analysis of alternatives and a BCA." MNSC's initial brief, pp. 103, 106; *see also*, *id*., pp. 101-106.

DTE Electric disputes AGMN's rationale for their proposed disallowance. The company states that there are clear distinctions between investments in this case and those planned for beyond 2025 that have been stated in testimony and discovery and that investments beyond 2025 "will shift focus and scope of investments to remaining substations and last mile investments that will be presented in the 2025 [distribution plan] and the next rate case." 4 Tr 841. DTE Electric states that while it did indicate in discovery that deployments in 2026 and beyond are outside this case, the company did "provide[] a list of [its] 2024 and 2025 fiber deployments by route and identified the substations associated with each route." 4 Tr 842. Moreover, per the company:

> The absence of exact routes to be deployed beyond 2025 does not warrant disallowance in the instant case, as they are distinct from the instant case investments to connect critical distribution sites. However, the absence of the exact routes beyond 2025 can be understood as explained in my direct testimony on page SMH-27, lines 19-20, the plan beyond the instant case "will continue to expand the telecommunication network to the next tier of locations that are prioritized from a resiliency perspective." Page SMH-48, lines 1-3 of my testimony also explains that "[i]n 2026 and through the end of the program, fiber routes will run through a cost benefit analysis to support the selection of the appropriate future technology to be used." Both sentiments were reiterated in the Company's MNSCDE-7.4(c) discover [sic] response, provided in Witness Alvarez's Exhibit MEC-8, along with the acknowledgement that the tool for determining deployments beyond 2025 is not yet complete.

4 Tr 842-843. The company further contends that its 2023 distribution plan does in fact provide additional information on its Telecommunications Plan, pointing to Exhibit A-23, Schedule M8, pages 137 and 141. Succinctly, per DTE Electric:

> The general Telecommunications plan scope as stated in the DGP, Exhibit A-23, Schedule M8, page 142-143, is as follows: "Between 2024 and 2028 fiber routers will be installed to complete fiber loops and provide communications to end points. This work will include installing communication poles, fiber entrances and taps along installed routes to make final connections into substations and support the advanced mesh network deployment with additional mesh nodes."
>
> Testimony, pages SMH-25 through SMH-28, segregates the plan into three general phases. (1) Installation and commissioning of the fiber backbone to critical sites will continue through 2025. (2) Investments in 2026 through 2028 will focus on extending of the backhaul network to next tier locations that cannot be sufficiently served by existing deployed technologies or currently do not have communications capabilities. (3) Finally, future investments beyond 2028 in grid telecommunications will focus on building out the last mile network to pole top devices.
>
> For the instant case, the first phase, the installation of the backbone to critical sites, will run through the end of the test year—2025. A listing of more detailed work scope planned and installed between 2022 and 2025 is listed on pages SMH-42 through SMH-45. Additionally, exact routes were provided in MNSCDE-7.4(b), presented in Witness Alvarez's Exhibit MEC-8, for 2024 and 2025.

4 Tr 844. The company further argues that it did provide an analysis of alternatives as required by the December 1 order, pointing to testimony provided at 4 Tr 655-668, which the company asserts

supports the use of company-owned fiber for the backhaul network to connect critical assets and the associated investment of $35.7 million. 8 Tr 845-847. DTE Electric further disputes AGMN's recommendation for a benefit-cost or make versus buy analysis, asserting that the company provided the make versus buy study characteristics in this case, that the company has committed to developing a BCA for the next phase of its Telecommunications program, and that the company is currently developing the BCA tool for determining fiber deployments beyond 2025. 8 Tr 848-850. The company further disputes the practicality of the level of precision that AGMN seeks for a benefit cost or make versus buy analysis and asserts that the Commission should reject AGMN's additional recommendations about the need for an independent expert to complete a comprehensive analysis and to compare the options and for the company to complete a tool that identifies best alternatives in various situations and circumstances. 4 Tr 850-852. Per DTE Electric:

> The Company does not believe all four analyses [BCA, make versus buy analysis, a comprehensive analysis by an independent expert, and a tool to identify the best alternative] are required at this time and are redundant of each other. In the instant case, the Company provided a comparative analysis of alternative technologies on pages SMH-29 through SMH-42 of [company] testimony for use connecting critical distribution sites pursuant to the Commission's order in Case No. U-21297 on December 1, 2023. Additionally, the Company is committed to developing a benefit cost analysis for determining deployments beyond 2025, as stated in [ ] direct testimony on page SMH-48, lines 8 1-4. The tool is not yet completed and was acknowledged in MNSCDE-7.4(c), presented in Witness Alvarez's Exhibit MEC-8.

4 Tr 853. The company lastly disputes AGMN's presumptions, arguing that real-time communications are indeed required to operate the technologies in a modern grid and that the company did not presume company-owned options provide the best combination of attributes. 4 Tr 853-855; *see also*, DTE Electric's initial brief, pp. 134-140, and DTE Electric's reply brief, p. 48.

In briefing, the Staff responds to AGMN by recapping the company's rebuttal to AGMN's arguments. The Staff overall recommends no adjustments to the company's technology and automation expenditures at this time. Staff's initial brief, pp. 193, 194 (citing 4 Tr 851, 6 Tr 3978, 6 Tr 5157).

The Commission finds that the company provided direct comparisons between the alternatives, as specified in the December 1 order. As a result, the Commission finds sufficient evidence for recovery of the company's historical and bridge year spending. However, the company's failure to provide quantitative cost comparisons between the alternatives results in an insufficient record to support the company's projected 2025 spending. Thus, the Commission disallows the company's projected capital expenditures of $15 million at this time. For future Grid Automation Telecommunications investments, the company's BCA or alternatives analysis should include both qualitative comparisons between available technologies and quantitative cost comparisons. Additionally, the company should provide a more comprehensive description of the total scope of this project/program moving forward.

iii. Non-Wires Alternatives Pilots

DTE Electric has nine NWA[25] pilots, which include the company's first, completed pilot at Hancock Station and the following remaining pilots: (1) O'Shea Energy Storage; (2) Mobile Battery Trailer; (3) Omega Load Relief; (4) Fisher; (5) Port Austin; (6) Veridian; (7) EV Charging Demonstration at American Center for Mobility (ACM); and (8) Adaptive Networked Microgrid

[25] The Commission has previously defined non-wires alternatives to mean "[a]n electricity grid investment or project that uses distribution solutions such as [DER], energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades." August 20, 2020 order in Case No. U-20147, p. 11.

(ANM).[26] 4 Tr 679-680; Exhibit A-12, Schedules B5.4.1-B5.4.7, B5.4.9; DTE Electric's initial brief, pp. 141-142.

With respect to the ANM pilot, DTE Electric states that the company has been selected by the U.S. Department of Energy (DOE) for federal Infrastructure Investment and Jobs Act (IIJA), PL 117-58, grant funding to expand the company's NWA work. DTE Electric avers that the company will use this funding, which it expects to be finalized sometime in 2024, to expand deployments at the O'Shea solar park and Port Austin substation and to incorporate ANMs to further increase customer benefits for these assets. 4 Tr 699. DTE Electric further states that the company has formed partnerships with various entities within the research and development community, who will contribute $1 million in funding for the approximately $46 million cost of the pilot. 4 Tr 702-703. IIJA funding will constitute $23 million of the cost of the pilot, leaving DTE Electric responsible for approximately $22 million in funding. 4 Tr 703. DTE Electric seeks recovery for expenditures for the ANM pilot of $4,606,000 for the bridge period and $25,550,000 for the test year, with IIJA grant and partner funding offsetting these expenditures by $2,609,000 and $13,110,000 in the bridge period and test year, respectively. 4 Tr 704; Exhibit A-12, Schedule B5.4, p. 17, lines 26 and 27.

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[26] DTE Electric states that:

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

4 Tr 701.

The Staff provides testimony that, in response to a discovery request, DTE Electric indicated that the company would not continue to develop the ANM pilot if IIJA grant funding could not be secured. 6 Tr 5065; *see also*, Exhibit S-10.7, p. 9. The Staff states that, although DTE Electric provided an update on the status of the company's grant application to the DOE, the company did not confirm whether the IIJA grant funding has been awarded.[27] 6 Tr 5064-5065, 5066. The Staff asserts that it is "generally supportive of [the ANM pilot] and the value that it could provide the Company through the development and operation of adaptive microgrids[;]" however, with the status of the company's IIJA grant funding uncertain, the Staff does not find it appropriate to include the pilot in recovered rates. 6 Tr 5065. Accordingly, the Staff recommends a disallowance of $30.138 million for requested expenditures for the ANM pilot for the bridge and test years in this case. *See*, 6 Tr 5065; *see also,* Staff's initial brief, p. 45. The Staff further recommends that the corresponding partner contributions and grant funding that offset the costs of the pilot be credited to ensure that the pilot has no impact on the revenue requirement. *See*, 6 Tr 5065; *see also,* Staff's initial brief, p. 45. The Staff further asserts that, since the as filed in-service-date for the ANM pilot is 2027, the proposed disallowance will not impact revenue requirement. Staff's initial brief, p. 46; *see also*, Staff's reply brief, Appendix E, p. 1, lines 25 and 26.

In rebuttal, DTE Electric states that the company appreciates the Staff's support and interest in the ANM pilot, and that the company "will continue working diligently with the [DOE] to reach a funding agreement to legally secure the grant and commence engineering design. Since the as-

[27] As part of a response to a discovery request for project costs for certain distribution investments in the company's DGP, the Staff indicates that it received a comment from DTE Electric appearing to suggest that the company received a grant award from the DOE for the pilot but that the company failed to confirm the award of any grant. 6 Tr 5066; *see also*, Exhibit S-10.8.

filed in-service date of the project is 2027, the disallowance of [the ANM pilot] does not impact the revenue requirement." 4 Tr 856; *see also*, DTE Electric's initial brief, p. 147. Accordingly, DTE Electric states that the Staff's concern regarding the ANM pilot "appears to be resolved." DTE Electric's reply brief, p. 49.

The Commission agrees with the Staff that it is inappropriate to include the capital expenditures in the revenue requirement given the uncertainty of DTE Electric's IIJA grant funding and the company's indication that it would not continue to develop the ANM pilot absent such funding. *See*, 6 Tr 5065; *see also*, Exhibit S-10.7, p. 9. The Commission finds that the parties agreed to the Staff's proposed disallowance and credit and considered the issue to be resolved. *See*, DTE Electric's reply brief, p. 49. The Commission, therefore, adopts the Staff's proposed disallowance of $30.138 million for requested expenditures for the ANM pilot and proposed credit for partner contribution and grant funding, and notes that this disallowance does not impact the revenue requirement in this case.

The CEOs state that they agree that DTE Electric's NWA pilots are important building blocks for future planning and operating capabilities, and as a result, recommend that the Commission approve the company's NWA pilots. 6 Tr 3262. But the CEOs argue that DTE Electric's NWA pilots rely primarily upon DTE Electric-owned assets and that the company "will gain experience with non-conventional solutions utilizing customer-owned DER with its Veridian NWA pilot." 6 Tr 3257. The CEOs further contend that DTE Electric has not explained how the company will scale up piloted technologies and incorporate them into the distribution planning process. 6 Tr 3263. As a result, the CEOs recommend that the Commission order DTE Electric to develop a framework for non-conventional solutions in the company's next DGP that, among other things, defines the company's approach for scaling up piloted technologies and incorporating NWA solutions into the distribution planning process. 6 Tr 3264; *see also*, the CEOs' initial brief, p. 21. With respect to additional NWA pilots, the DAAOs recommend that the Commission require DTE Electric to evaluate an underground geothermal network as a pilot project for at least one resilience microgrid in Highland Park. 6 Tr 4629; *see also*, the DAAOs' initial brief, pp. 88-89. Similarly, GLREA recommends that the Commission direct DTE Electric to propose a pilot of geo-targeted incentives for customer-owned solar systems (including batteries) in the company's next rate case or DR case. 6 Tr 4849; *see also*, GLREA's initial brief, p. 26.

In response, DTE Electric disagrees with expanding its current NWA pilots. The company also states that it "screens load-related strategic investments for NWA opportunities and typically finds the load constraints that are being addressed are generally not suitable for NWA projects." 3 Tr 446. As such, DTE Electric argues that it is "committed to completing the NWA pilots underway and communicating lessons learned and results in order to inform discussions to scale the piloted technologies." 3 Tr 467. The company further argues that it has already incorporated NWA options into its grid planning and that, although the company does not have current plans to expand its current NWA pilots, the company will continue to evaluate promising and new technologies for future potential pilots. 3 Tr 468; *see also*, DTE Electric's initial brief, p. 148; DTE's reply brief, p. 49.

The Commission finds that DTE Electric has begun to incorporate NWA options into the company's grid planning and, thus, is not persuaded that the company should be required to expand its current portfolio of NWA pilots or incorporate NWA solutions into its distribution planning process at this time. *See*, Exhibit A-12, Schedules B5.4.1-B5.4.7, B5.4.9. Rather, the Commission agrees that DTE Electric should continue to focus on the company's current NWA pilots to obtain results that will better inform the company on how to scale its current NWA pilots and better identify opportunities that are suitable for NWAs with relevant findings incorporated into the company's DGP. The Commission acknowledges the intervenors' arguments that there may be other technologies or prospective pilots that could be investigated by the company and, therefore, encourages DTE Electric to continue to evaluate and explore ways to maximize value and efficiency of the distribution system and to propose future potential pilots as appropriate, including, where appropriate, pilots proposed through the expedited pilot process established in Case No. U-20898.

iv. Grid Management

DTE Electric states that grid management investments enable the company to monitor, control, and optimize the operation of Grid Automation investments. 4 Tr 720. The company further states that grid management investments include Other Modernize Grid Management investments, which "is a category of investments that encompass a diverse set of projects designed to enhance the Company's operational capabilities, particularly during high-volume outage events, those that impact hundreds or thousands of customers." 4 Tr 729. Key investments in this category include Error Free Communication (EFC) Communications – Outage Status. 4 Tr 730; *see also*, DTE Electric's initial brief, p. 151. With respect to the company's EFC Communications—Outage Status initiative, DTE Electric states that the company is forecasting to spend approximately $50.0 million in total capital for the years 2022-2025, which excludes $2.4 million in 2021 capital previously requested and approved for recovery in Case No. U-21297. 6 Tr 2252. For EFC Core systems, DTE Electric is seeking $5.8 million in incremental capital expenditures in this case ($5.2 million for the 2023-2024 bridge years; and $0.6 million for the test year). 6 Tr 2257; *see also*, Exhibit A-24, Schedule N7, pp. 1-2. For EFC Customer-Facing systems, DTE Electric is seeking approximately $16.8 million in additional capital expenditures for the period 2022-2024. *See*, 6 Tr 2264; *see also*, Exhibit A-24, Schedule N7, pp. 3-4. The company asserts that these expenditures will, among other things, improve restoration estimates timeliness and accuracy for customers, as well as outage tracking and reporting. 6 Tr 2258-2264.

The Staff supports DTE Electric's request for capital expenditures for the company's EFC-Outage Status initiative and, therefore, does not recommend any monetary adjustments to the program. 6 Tr 5101; *see also*, Staff's initial brief, p. 175. However, the Staff notes that it would like DTE Electric "to continue to focus on the established metrics and improvements delineated in testimony: power restoration accuracy and timeliness, first estimate accuracy, and outage notification delivery." 6 Tr 5102. Additionally, the Staff would like the company to strive for improvements noted in audit responses. 6 Tr 5102-5103; *see also*, Exhibits S-18.1, S-18.2, and S-18.3. In turn, the Staff recommends that, going forward, the Commission require DTE Electric to provide detailed descriptions of continuous improvements, as well as any failures, experienced with the EFC program and its various components. 6 Tr 5103. The Staff further recommends that the Commission require DTE Electric to "demonstrate specific goals it expects to achieve in areas concerning Outage Status and Reporting Dashboards, the Company's visibility into the customer's outage experience, and Customer-Facing Systems, expected timelines for these goals, and ultimately, the execution of goals, including the costs to achieve them." 6 Tr 5103. Finally, the Staff recommends that the Commission require the company to provide the Staff with continuous status updates, preferably in the form of biannual meetings, as well as detailed updates in future rate cases. 6 Tr 5103-5104; *see also*, Staff's initial brief, pp. 175-176. DTE Electric does not rebut the Staff's recommendations.

Finding that DTE Electric did not dispute the Staff's recommendations, the Commission agrees with the Staff and directs DTE Electric, in future rate cases, to provide detailed status and expenditure updates on the company's expenditures for the EFC program demonstrating the results of any investments in this program. The Commission further directs the company to meet with the Staff in the form of biannual meetings to provide detailed status updates on any continuous improvements, as well as failures, in the EFC program and its various components.

5. Community Lighting

a. Underground Cable Replacement Program

DTE Electric's capital expenditures for community lighting were $17.82 million in 2022, and are expected to be $16.70 million in 2023, $16.70 million in 2024, and $17.30 million for the projected test year. 6 Tr 3119; Exhibit A-12, Schedule B5.5.

MI-MAUI states that it supports DTE Electric's community lighting capital expenditures with the exception of expenditures related to the company's underground cable replacement program. MI-MAUI contends that DTE Electric has failed to demonstrate that the program is cost-effective and has provided no data to support the company's current prioritization for replacement, including data on how many streetlights have been impacted by outages or data on the correlation between aging cables and failure rates. *See*, 6 Tr 4316-4318. Accordingly, MI-MAUI recommends that the Commission disallow $15.575 million in expenditures for the program, and further require DTE Electric to support the company's plans for unground cable replacement in the company's DGP or in future rate cases. 6 Tr 4318-4319, 4327-4328.

In rebuttal, DTE Electric disagrees with MI-MAUI's proposed disallowance and argues that the company has identified the specific criteria used to prioritize and replace failed and/or end-of-life underground cables. 6 Tr 3162. As an example of the types of cable replacement candidates the company targets, DTE Electric describes a recent cable replacement project that took place in the City of Riverview, including the criteria used to prioritize the project (i.e., cable age, previous outages reported on the circuit, pedestrian traffic, lights currently impacted). 6 Tr 3163-3164. The company further argues that, if the Commission were to deny recovery of the capital costs of these projects, underground cable repairs would only be made through more costly locate and repair methods that would not mitigate the root causes of the cable failures. 6 Tr 3162. Additionally, DTE Electric disputes that the failure to include the underground cable replacement program in the company's DGP should serve as a basis for a disallowance as the DGP's focus is specific to distribution investments and does not extend to community streetlighting that is distinct from the company's distribution system. 6 Tr 3164-3165; *see also*, DTE Electric's initial brief, p. 166.

MI-MAUI responds that, in rebuttal, DTE Electric "described a very different program, in which projects were selected based on a known history of outages and actual knowledge of the repair history and performance of the cable to be replaced." MI-MAUI's initial brief, p. 16. MI-MAUI then states that if DTE Electric is seeking to replace underground cables with known performance issues, then MI-MAUI "does not object to the inclusion of the program expenses in the revenue requirement." *Id*., p. 17. However, MI-MAUI maintains its proposal that the company should be required to include the program in its DGP, arguing that investments in streetlighting infrastructure should be subjected to the same level of scrutiny as investments in the distribution system. *Id*., pp. 17-18. In reply, DTE Electric states that the issue surrounding the proposed disallowance for capital expenditures appears to be resolved and maintains the company's position that the program should not be required to be included in the company's DGP. DTE Electric's reply brief, pp. 53-54.

The Commission finds that, based on the representations made in MI-MAUI's initial brief, the issue regarding MI-MAUI's proposed disallowance of capital expenditures for the underground cable replacement program is resolved. *See*, MI-MAUI's initial brief, pp. 16-17. Accordingly, the

Commission rejects MI-MAUI's proposed disallowance of these costs. With respect to MI-MAUI's proposal to require DTE Electric to include the program in the company's DGP, the Commission agrees that community streetlighting is distinct from the company's distribution system, and therefore, declines to adopt MI-MAUI's proposal on this issue at this time.

b. Light Emitting Diode Conversions

In Case No. U-21297, MI-MAUI advocated for a partial disallowance of $5.8 million of capital expenditures for community lighting, arguing that the disallowance was warranted because DTE Electric was installing brighter and more expensive light emitting diode (LED) luminaires than was necessary to meet applicable standards when converting existing high-intensity discharge (HID) and high-pressure sodium (HPS) luminaires. *See*, December 1 order, p. 136. MI-MAUI calculated the partial disallowance based on the difference between DTE Electric's installed LED luminaires and the LED luminaires recommended in a crossover chart provided by Leotek, LLC (Leotek) DTE Electric's primary roadway luminaire vendor. *See*, *id*., pp. 135-136. In the December 1 order, the Commission found that DTE Electric had failed to demonstrate that its re-lamping policy was reasonable and prudent, and therefore, adopted MI-MAUI's proposed disallowance. *Id*., p. 139.

In the present case, DTE Electric requests the Commission to revisit the partial disallowance adopted in Case No. U-21297, arguing that recovery should be permitted because Leotek has since disavowed the crossover chart upon which the previous disallowance was based and because independent experts have reviewed the company's current conversion recommendations and have found them to be reasonable. 6 Tr 3122; DTE Electric's initial brief, p. 161. According to DTE Electric, new streetlighting installations are evaluated in accordance with the American National Standards Institute (ANSI)/ Illuminating Engineering Society (IES) RP-8 standards, but conforming conversion projects to this standard would be impractical because these lighting systems predate the standard and would require extensive reconfiguration, including pole relocations and rewiring. 6 Tr 3119-3120. As a result, DTE Electric states that the company's objective during conversion projects is to restore lighting to the initial output of the original HID luminaire with an LED luminaire. 6 Tr 3120. DTE Electric further states that the primary criteria the company evaluates when selecting an appropriate LED luminaire for conversion projects are illuminance and luminance,[28] and that the company conducted lighting modeling that demonstrated that 58W and 136W LED luminaires were most appropriate to replace existing 100W and 250W HPS luminaires, respectively. 6 Tr 3123, 3124-3125. The company argues that two independent experts reviewed the company's method for choosing an appropriate replacement luminaire and determined that the company's recommended LED luminaires were appropriate. 6 Tr 3123-3124; DTE Electric's initial brief, p. 161. Based on this new evidence, DTE Electric makes four recommendations for the Commission's consideration: (1) that it would be prudent to continue to utilize 58W and 136W LED luminaires when converting HPS luminaires; (2) that the Commission should revisit and permit recovery of the previously disallowed capital expenditures; (3) that DTE Electric be permitted to memorialize the company's replacement LED recommendations in customer contracts and explicitly inform the customer during contract negotiations that the customer has a choice to select an alternate LED luminaire; and (4) that the Staff conduct a technical workshop that includes Consumers to compare and contrast the

[28] DTE Electric states that "roadway illuminance" is the measurement of the amount of light that hits the pavement surface and that "roadway luminance" is the measurement of the reflected light from the pavement surface that is visible to the motorist's eye. 6 Tr 3125 (citing the Texas Department of Transportation's Highway Illumination Manual, available at https://onlinemanuals.txdot.gov/TxDOTOnlineManuals/TxDOTManuals/hwi/illumination_levels.htm#i102 (accessed December 4, 2024)).

companies' LED selection methodologies.[29] 6 Tr 3130-3131; DTE Electric's initial brief, pp. 161-164.

MI-MAUI disagrees with DTE Electric's recommendations and argues that the company's recommended replacement LED luminaires are not prudent. MI-MAUI asserts that DTE Electric provides no data to support the company's contention that it would be impractical to conform conversion projects to current standards, and that the company's own modeling and data show that the company's recommended LED luminaires significantly over-light roadways relative to current standards.[30] Moreover, MI-MAUI argues that lower-wattage LED luminaires would better approximate applicable standards, would cost customers less, and have been used by other streetlight providers, including Consumers, for similar replacements. 6 Tr 4343. Additionally, MI-MAUI argues that Leotek's removal of its crossover chart does not excuse the need for DTE Electric to demonstrate why the company's recommended LED luminaires are necessary to meet current standards and that the company's experts only focused on the comparability of the company's recommended LED luminaires for common HID luminaries, but not that such replacements were necessary to meet ANSI/IES standards. 6 Tr 4342-4343; MI-MAUI's initial brief, p. 5. Because this evidence fails to address the standard outlined in Case No. U-21297, MI-MAUI advocates for the Commission to deny recovery of any previously disallowed expenditures. Furthermore, MI-MAUI proposed that the Commission disallow $7,705,567 in

[29] Regarding DTE Electric's fourth recommendation, the company originally recommended that the Staff conduct a technical workshop with the company, Leotek's engineering team, outside consultants, and MI-MAUI to evaluate HID to LED equivalent conversions. However, based on MI-MAUI's proposed alternative disallowance based on Consumer's LED equivalencies, the company amended its recommendation. *See*, DTE Electric's initial brief, p. 164.

[30] For example, MI-MAUI contends that the company's recommended 58W and 136W replacement LED luminaires are on average 188% and 317% of the luminance required in standards, respectively. 6 Tr 4341-4342.

capital expenditures, which MI-MAUI states is based on the most recent equivalency recommendations from Leotek. Alternatively, MI-MAUI recommends that the Commission disallow $5,833,539, which MI-MAUI states is based on using Consumers' LED equivalencies as a benchmark. 6 Tr 4346-4347; *see also*, Exhibit MAU-34. With respect to DTE Electric's recommendation to memorialize customers' ability to choose an alternate LED luminaire from the company's recommended fixtures, MI-MAUI contends that the recommendation is insufficient to meaningfully empower customers, and that the recommendation improperly places the onus on customers to evaluate the reasonableness and cost effectiveness of the company's standard offerings. 6 Tr 4331; MI-MAUI's initial brief, pp. 8-9. Finally, regarding the recommendation for a technical workshop, MI-MAUI states that it is open to discussing streetlighting concerns with DTE Electric and other pertinent participants, but that it has concerns regarding the timing of such a workshop and the obstacles that may occur if the company has an active rate case at the time the workshop is conducted. MI-MAUI's initial brief, pp. 10-11.

The Staff states that it reviewed DTE Electric's proposal for a technical workshop and recommends that the Commission should direct the Staff to work with interested parties to conduct a technical workshop about streetlighting, which the Staff believes would help the Staff, DTE Electric, and MI-MAUI to better understand streetlighting and reach conclusions regarding the best approach for HID to LED conversions. Staff's initial brief, pp. 192-193.

In rebuttal, DTE Electric argues that MI-MAUI's assertion that the company's LED recommendations over-light roadways is not accurate and that when these recommendations are adjusted with a light loss factor (LLF), luminance falls within industry standards—namely guidelines outlined in the Federal Highway Administration's (FHA) handbook[31]—and that MI-MAUI's recommended luminaires fall below maintained lighting levels. 6 Tr 3174-3175; *see also*, DTE Electric's initial brief, pp. 163-164. Further, the company argues that, in Case No. U-21297, Leotek's crossover chart became the new standard that DTE Electric was required to use when converting 100W and 250W HPS luminaires and that the previous disallowance, as well as the disallowance proposed by MI-MAUI in this case, relied solely on that chart. Because Leotek no longer supports the chart, DTE Electric advocates for the Commission to reject MI-MAUI's proposed disallowance and instead to order a technical workshop. 6 Tr 3171-3172, 3176-3177. MI-MAUI replies that, even when accounting for LLF, MI-MAUI's recommended luminaires, on average, fall an insignificant 2% below maintained lighting levels and demonstrate that DTE Electric's recommended higher wattage luminaires are unreasonable given that interim LED wattages are available. MI-MAUI's initial brief, pp. 6-7. MI-MAUI also claims that revisiting the previously disallowed expenditures would constitute unlawful retroactive ratemaking. *Id*., pp. 11-12.

The Commission has reviewed the record and is not persuaded that the new evidence presented by DTE Electric in this case justifies recovery of the $5.8 million in capital expenditures previously disallowed in Case No. U-21297. In the December 1 order, the Commission stated that it was:

> telling that the company fail[ed] to support its more expensive LED choices by referring either to compliance with the ANSI/IES RP-8 standards or compliance with a manufacturer's specifications. Rather, the company [was] simply guided by the original lumen output, which does not equate to compliance with the

[31] DTE Electric states that the pertinent standard recommends "that lighting not exceed the maintained lighting level specified for the roadway by more than 50%. . . designers are encouraged to get as close as possible to the required maintained level *while not going below that level*." 6 Tr 3175 (citing Exhibit A-40, Schedule EE7) (emphasis in original).

relevant standards and is based on an outdated technology that is undergoing replacement.

December 1 order, p. 139. As such, the Commission clearly found that the reasonableness and prudence of the company's LED replacement luminaire recommendations necessarily centered on meeting applicable standards, and not merely on meeting lumen output from original HID and HPS luminaires.

The Commission agrees with MI-MAUI and finds that DTE Electric has not provided sufficient evidence to demonstrate why conforming replacement projects to ANSI/IES standards is impractical or why the company's more expensive LED replacement luminaires are necessary to comply with these standards. Instead, the Commission finds that the evidence provided merely relates to the company's methods and choices for replacing the lumen output from original HID and HPS luminaires, and not whether these choices comply with current standards.[32] Accordingly, the Commission rejects DTE Electric's proposal to permit recovery of the $5.8 million in capital expenditures disallowed in Case No. U-21297.

With regard to MI-MAUI's proposed additional disallowances, the Commission finds that DTE Electric presented evidence on the record that, when adjusted with an LLF, the luminance of its LED choices falls within the guidelines outlined in the FHA handbook. Moreover, even though the handbook explicitly advises that maintained lighting levels not go below the required maintained lighting level, MI-MAUI concedes that its recommendations do just that, falling two percent below the FHA-prescribed maintained lighting level. While MI-MAUI describes the failure to meet this lighting level as "insignificant," it seems clear that the FHA intended the

[32] Indeed, DTE Electric's own third-party expert concedes that the "method of comparing to incumbent technology assumes that the existing technology does not over- or under-light the roadway." Exhibit A-25, Schedule O9, p. 3.

maintained lighting level to be a minimum, and the Commission therefore disagrees that the maintained lighting level standard can be ignored. As such, the Commission declines to adopt either of MI-MAUI's proposed additional disallowances in the present case.

However, while the Commission finds that DTE Electric in this case adequately demonstrated that the company's LED choices met FHA standards, the Commission remains convinced that there is still ample room for improvement in the company's streetlighting program, including a closer nexus with the maintained lighting levels of the FHA handbook, as well as relevant ANSI/IES standards that have been the basis of much of the disputes between DTE Electric and MI-MAUI in the past several rate cases. As such, the Commission directs the Staff to conduct a technical workshop with DTE Electric, MI-MAUI, pertinent roadway luminaire manufacturers, vendors, and/or engineers, Consumers, and other interested persons to evaluate and explore the following: (1) the practicality and cost effectiveness of performing conversion projects that comply with relevant ANSI/IES standards, as opposed to merely matching the lumen output of original HID and HPS luminaires; (2) comparing and contrasting the LED luminaire selection methodologies of DTE Electric and Consumers; (3) determining appropriate recommended LED luminaires for conversion projects; and (4) determining appropriate methods for conducting meaningful discussions with customers regarding recommended LED luminaires for conversion projects. The Commission expects that the findings of this technical workshop will help inform DTE Electric's future streetlighting strategies and will help the Commission better evaluate the reasonableness and prudence of streetlighting investments in the future.

c. Contribution in Aid of Construction Bill Credit

Ann Arbor states that it has opted to convert the city's streetlights to non-standard LED luminaires to meet goals for advancing sustainability practices, decrease its carbon footprint, and accommodate public lighting preferences. 6 Tr 4226-4227, 4228-4229. As a result of transitioning to these LED luminaires, Ann Arbor asserts that it has been required to pay a CIAC equal to the total construction cost, including labor, materials, and overhead, in the amount of $1,021,700.97. 6 Tr 4226. Ann Arbor argues that this requirement is unfair and that it should receive a bill credit "equal to the monies other customers will not have to pay to convert the City's streetlights. Otherwise, the City is paying to help with the installation costs for other customers making this transition, but they are not paying anything to help with our transition." 6 Tr 4231; *see also*, Ann Arbor's initial brief, pp. 13-15.

This issue, including related arguments raised by DTE Electric, MI-MAUI, and the Staff, is detailed below (Streetlighting Rate Design). Consistent with the Commission's decision, as set forth below, the Commission rejects Ann Arbor's recommendation and instead finds that DTE Electric should adopt a time-limited bill credit per each LED light per year which is adjusted as new rates incorporate changes. 6 Tr 4305; *see also*, March 1, 2024 order in U-21389, Attachment B, Sheet No. D-94.00.

6. Demand Response Programs and DTE Insight

a. SmartCurrents Program

DTE Electric spent $8.0 million in capital expenditures for its DR portfolio in 2022 and is seeking to spend an additional $17.4 million and $4.4 million in capital expenditures for the DR portfolio in the bridge period and test year, respectively. 6 Tr 2672; Exhibit A-12, Schedule B5.6, p. 1. Included in the company's DR portfolio is the Programmable Controllable Thermostats (PCT or SmartCurrents) program, an offering whereby residential and commercial customers receive a PCT that enables the company to adjust the thermostat during SmartCurrents events. 6 Tr 2666. For the SmartCurrents program, DTE Electric forecasts capital expenditures of $8.3 million for the bridge period and $2.5 million for the test year. 6 Tr 2678-2679; Exhibit A-12, Schedule B5.6, p. 2, line 10. DTE Electric notes that the company and the Staff previously agreed to a partial disallowance of $1,672,895 in capital expenditures associated with the SmartCurrents program in the company's 2021 DR reconciliation case, Case No. U-21242, which represents the difference between the company's actual spend on the program and the amount originally preapproved in the company's 2019 IRP, plus 10 percent. 6 Tr 2681. DTE Electric avers that the overspend on the SmartCurrents program was primarily due to the creation of a new webpage to redesign and enhance participating customers' experiences. According to DTE Electric, the Staff recommended the agreed-upon disallowance because, at the time of the company's 2021 DR reconciliation filing, the company could not correlate increased enrollments and event participation to the development of the new webpage. 6 Tr 2681. However, in this case, DTE Electric argues that the capital expenditures have demonstrably added value to the SmartCurrents program and are, therefore, reasonable and prudent. Specifically, the company argues the redesigned webpage added value by increasing conversion rate from 14% to 46%, decreasing processing enrollment average times from seven days to one, increasing enrollments by 50% in the year the webpage went live (as compared to the previous year), and enrolling 98% of participating customers through the webpages' self-service channel. 6 Tr 2682. DTE Electric, in turn, seeks recovery of the previously disallowed expenditures, which will add $914,448 to the projected test year rate base.[33] 6 Tr 2682; DTE Electric's initial brief, p. 169.

The Staff argues that the Commission should reject DTE Electric's request to recover the previously disallowed capital expenditures for the SmartCurrents program. According to the Staff,

[33] As DTE Electric notes, the company has not included the previously disallowed capital expenditures in the company's balance sheet in this case. *See*, 6 Tr 2682; *see also*, Exhibit A-2, Schedule B6.1.

its position on the previous disallowance has not changed because "the Company significantly exceeded what was preapproved in the Company's 2019 [IRP] for this program, failed to communicate with Staff that it was exceeding investment by more than 10% as previously agreed, and that the benefits from the increased investment did not exist or were unclear."
6 Tr 5075-5076; Staff's initial brief, p. 152. The Staff further states that these capital expenditures were at issue in the company's 2021 and 2022 DR reconciliation cases and were incorporated in approved settlement agreements for these cases, which the Staff asserts were appropriate.
6 Tr 5076; *see also*, January 19, 2023 order in Case No. U-21242, Exhibit A, p. 2; March 15, 2024 order in Case No. U-21403, Exhibit A, Attachment 1, p. 1. Accordingly, the Staff maintains that the disallowed expenditures should not be recovered in this case. 6 Tr 5076; *see also*, Staff's initial brief, p. 152.

In rebuttal, DTE Electric acknowledges that the company overspent the preapproved amount in the company's 2019 IRP but maintains that the disallowed expenditures added customer value to the SmartCurrents program and that, as a result, the expenditures should be considered reasonable and prudent and therefore recoverable. 6 Tr 2721.

The Commission disagrees with the Staff's contention that the previous settlement agreements associated with DTE Electric's 2021 and 2022 DR reconciliations necessarily prevent recovery of previously disallowed capital expenditures for the SmartCurrents program in this case. Although these settlement agreements were appropriate at the time they were entered into, the Staff has not refuted the evidence proffered in this case regarding the added value to the SmartCurrents program provided by the previously disallowed capital expenditures. Specifically, the Commission finds that DTE Electric has adequately demonstrated that the excess capital expenditures were primarily used to create a new webpage for the SmartCurrents program, and that this new webpage added value to the program. *See*, 6 Tr 2682. Further, the Commission finds that the Staff and DTE Electric previously agreed to the requirement that the company provide updates to the Staff "of any spending above approved amounts once overspending has exceeded 10% of approved amount *at the portfolio level* for 2020 and thereafter." February 18, 2021 order in Case No. U-20793, Exhibit A, p. 3 (emphasis added). As such, based on the plain language of the settlement agreement, the Commission rejects the Staff's argument that DTE Electric's failure to update the Staff of overspending on the SmartCurrents program should serve as a basis to deny recovery in this case. The Commission notes, however, that it continues to expect DTE Electric to demonstrate the cost-effectiveness of DR programs, including considering the impact of individual DR program contributions to overall cost-effectiveness. Accordingly, the Commission adopts the company's recommendation to allow recovery of $1,672,895 in previously disallowed capital expenditures associated with the SmartCurrents program, which adds $914,448 to the projected test year rate base in this case.

b. Commercial and Industrial Battery Storage Pilot

DTE Electric's C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate BESS that is designed to test the ability to achieve peak demand shaving or shifting during DR events. 6 Tr 2686. In the December 1 order, the Commission previously disallowed capital expenditures of approximately $2 million for the pilot based on DTE Electric's failure to secure a second participant for the pilot. December 1 order, p. 247. Regarding the current status of the pilot, however, DTE Electric asserts that both batteries have arrived, that the company has ordered switchgears, and that the company expects to have a second customer secured in the first half of 2024, with both batteries being operational by the end of 2025. 6 Tr 2687-2688. In turn, DTE Electric seeks recovery of the expenditures previously disallowed in Case No. U-21297, specifically, capital expenditures of $1.4 million during the bridge period to procure and install equipment and $0.6 million during the test year to support final installation costs. 6 Tr 2688-2689; DTE Electric's initial brief, p. 172; *see also*, Exhibit A-12, Schedule B5.6, p. 1, line 3.

The Staff notes its concerns about the amount of time it is taking DTE Electric to secure a second participant, arguing that the company has essentially been looking unsuccessfully for two years. 6 Tr 5166-5167; *see also*, Staff's initial brief, p. 48. Given this difficulty, the Staff recommends that DTE Electric limit the current pilot to a single participant and, accordingly, that the Commission disallow $2.0 million in expenditures for the pilot. 6 Tr 5167, 5170; *see also*, Staff's initial brief, p. 47. The Staff argues that limiting the current pilot to one participant would enable the company to focus on a single customer and allow more flexibility in the use of the second battery, which the Staff asserts should be used for a follow-up pilot once DTE Electric has obtained operational information from the current pilot. 6 Tr 5167. Additionally, the Staff recommends that DTE Electric be required to utilize a fee structure for participation in the follow-up pilot with a second participant. 6 Tr 5167. According to the Staff, it is important that the second participant be required to have some participation fee as the use of such a fee would be more representative of how a final BTM battery program would operate and would incentivize customers to utilize the storage to its highest capabilities to ensure participation costs were recouped. 6 Tr 5168.

Similarly, MEIU object to the approval of any additional expenditures for the second battery for the C&I battery storage pilot. Like the Staff, MEIU note that DTE Electric still has not secured a second participant for the pilot and, thus, argue that the circumstances upon which the Commission previously disallowed expenditures in Case No. U-21297 are unchanged. 6 Tr 4100. However, unlike the Staff, MEIU further argue that no additional spending should be approved for the C&I battery storage pilot and that DTE Electric should instead be required to shift the company's focus to rate design changes or pilots that can benefit a larger group of customers without utility-owned BTM batteries. 6 Tr 4104; *see also*, MEIU's initial brief, pp. 42, 44-45. According to MEIU, most of the benefits of utility-owned BTM batteries accrue to the company and not customers. Instead, MEIU advocate for the use of non-utility owned batteries provided through third-party developers, as well as the use of rate design solutions, to make these programs more attractive and efficient for customers. 6 Tr 4105-4109; *see also*, MEIU's initial brief, pp. 44-45.

In rebuttal, DTE Electric avers that the company continues to make progress on finding a second participant for the pilot and that the forecasted expenditures for the pilot are divided into project milestones, not necessarily on a per battery basis. Accordingly, DTE Electric opposes the Staff's and MEIU's proposed disallowance. 6 Tr 2714; *see also*, DTE's initial brief, p. 172. Additionally, DTE Electric argues that limiting the pilot to one participant would be inappropriate and would cause the company to lose the ability to compare the pilot with a second customer with a different load and operating characteristics, thus purportedly hindering the company's learnings. 6 Tr 2712-2713. Moreover, the company disagrees with the proposal to require a fee for participation in a subsequent pilot, arguing that such a fee would only further hinder the company's ability to find a second participant since customers must already pay large up-front costs to participate in the pilot. 6 Tr 2713-2714. With respect to MEIU's proposal, DTE Electric rebuts that the pilot's costs should be considered prudent and should, therefore, receive full recovery. 6 Tr 2715.

The Commission agrees with the Staff and MEIU and finds that a disallowance of $1,990,000 in capital expenditures is appropriate. Just as it did in the December 1 order, the Commission finds that it would not be reasonable or prudent to approve funding for a second customer that has not been identified or secured to participate in the pilot. *See*, December 1 order, p. 247. However, as MEIU note, the company may seek recovery of these expenditures in its next rate case should the company identify and secure a second participant for the pilot. Although the Commission finds that a disallowance of expenditures is appropriate, the Commission is not persuaded that DTE Electric should be required to limit the C&I battery storage pilot to a single participant or that the company should be required to conduct a follow-up pilot with the second battery that incorporates a fee structure for participation. While the Commission acknowledges that incorporating a fee structure into a follow-up pilot may be more representative of how a final program would work, the Commission finds that participants are already required to pay upfront costs associated with concrete pads and electrical work needed to participate in the pilot. *See*, 6 Tr 2713-2714; *see also*, DTE Electric's initial brief, p. 173. Accordingly, the Commission rejects the Staff's recommendations that the company limit the existing pilot to a single customer and utilize the second battery to conduct a pilot that incorporates a larger fee structure. DTE Electric should, instead, be permitted to operate the pilot as originally outlined. For this reason, the Commission is also not persuaded at this time that the company should be required to abandon the C&I battery storage pilot and instead work with interested persons to develop new rate designs or pilot programs that do not utilize utility-ownership of BTM batteries. Accordingly, the Commission rejects MEIU's recommendations on these issues.

c. Residential Generator Pilot

DTE Electric is conducting a residential customer-owned natural gas generator pilot that partners with Generac Grid Services to shift customers' electric load to the customers' generators during peak events. 6 Tr 2696-2697. DTE Electric states that the Commission previously authorized the pilot in the company's last rate case,[34] and that the company is now considering a second phase for the pilot that would target up to 200 additional participants. 6 Tr 2698-2699 (citing December 1 order, pp. 252-253).

Ann Arbor argues that DTE Electric's residential generator pilot and its associated costs should be disallowed. According to Ann Arbor, the pilot's shift of a customer's electric load to a gas generator is not in line with the company's stated climate goal of reducing carbon emissions and is, therefore, unreasonable and imprudent. 6 Tr 4272-4273. Rather, Ann Arbor asserts that the company should instead focus on crafting a similar pilot using batteries, not generators that rely on fossil gas. 6 Tr 4273; *see also*, Ann Arbor's initial brief, p. 17.

In rebuttal, DTE Electric asserts that Ann Arbor appears to misunderstand the purpose of the pilot, and further argues that the pilot is simply targeting customers who already have a home generator, and thus, is not incentivizing customers to purchase and install natural gas generators. 6 Tr 2716. DTE Electric further acknowledges that Ann Arbor's alternative proposal regarding residential batteries has merit but claims that the company is focused on the current generator pilot. 6 Tr 2717. In reply, Ann Arbor states that it did not misunderstand the purpose of the project and maintains its position that shifting electrical load to generators that burn fossil fuels is unreasonable and imprudent. Ann Arbor further argues that the company's pilot will increase wear and tear on generators and may create air and noise pollution for surrounding neighbors. Ann Arbor's reply, p. 18.

The Commission disagrees with the premise put forth by Ann Arbor that only pilots in line with the company's internal climate goals developed outside of a contested proceeding can be

[34] In the December 1 order, the Commission approved the Residential Generator Pilot, which DTE Electric forecasted to spend \$200,000 in capital expenditures over the bridge period and test year, and \$200,000 annually in O&M expenses. *See*, December 1 order, pp. 251, 252-253.

considered reasonable and prudent. As such, the Commission rejects Ann Arbor's recommendation to disallow expenditures on this basis. However, the Commission finds that DTE Electric has not provided sufficient evidence to support a request for additional capital expenditures for the purpose of expanding the pilot to an additional 200 participants. Indeed, it is unclear from the record whether DTE Electric is even requesting additional capital expenditures or O&M expense to expand the pilot. The record is devoid of any reference to detailed expenditure amounts associated with the company's request to expand the pilot, and merely refers to a nonspecific category of O&M expense associated with "Demonstrating and Selling Expenses-DR." *See*, Exhibit A-12, Schedule B5.6.2, p. 2; *see also*, Exhibit A-13, Schedule C5.9, line 9. Furthermore, in its initial brief, the company merely requests that the Commission approve "full funding" for the pilot. DTE Electric's initial brief, p. 174.

Additionally, the Commission finds that DTE Electric has failed to meet its burden of demonstrating the reasonableness and prudence of expanding the pilot by an additional 200 participants. The only justification provided by the company for expanding the pilot is to "provide the opportunity to offer the pilot to a larger subset of different customers." 6 Tr 2699. But this stated justification does not quantify or demonstrate how an expanded set of participants in the pilot would contribute to the pilot's main objectives in ways that the original set of participants could not. *See*, 6 Tr 2697-2698. Accordingly, to the extent DTE Electric is seeking recovery of additional capital expenditures to expand the pilot for an additional 200 customers, the Commission disallows any additional expenditures for this purpose. The Commission further notes that, in any future requests for funding to expand the number of customers participating in the pilot, DTE Electric should provide a quantifiable BCA demonstrating the value of adding additional participants.

d. Other Demand Response Proposals

i. Critical Peak Rebate Program and Grid Interactive Water Heater Pilots

GLREA recommends that the Commission require DTE Electric, in its next rate or DR case, to propose a critical peak (CP) rebate pilot program and a grid interactive water heater (GIWH) DR pilot program. 6 Tr 4841, 4847; *see also*, GLREA's initial brief, pp. 12-16. GLREA argues that CP rebates are advantageous because they offer a reward in the form of a bill credit, do not require utilities to maintain equipment at customer sites, and are not technology specific. 6 Tr 4831-4832; *see also*, GLREA's initial brief, pp. 12-13. Regarding the GIWH DR program, GLREA states that GIWHs allow utilities to control a water heater's set-point and heating rate, providing advantages—including the ability to store energy—over simpler interruption devices. 6 Tr 4841-4843. For both proposed programs, GLREA argues that the Commission should enable a third-party to create the programs in the event DTE Electric resists the creation of these programs. 6 Tr 4841, 4847.

The Staff raises concerns about the proposed CP rebate pilot program, asserting that CP rebate rates typically produce less per customer demand reduction than dynamic peak pricing (DPP) rates. Additionally, the Staff argues that all customers are required to pay for the CP rebate bill credits, which has the effect of making CP rebate rates less effective and at a greater cost than DPP rates. 6 Tr 4905. Accordingly, while not advocating for the rejection of GLREA's proposal, the Staff urges the Commission to carefully consider the cost effectiveness of the CP rebate pilot program should it be approved. 6 Tr 4905; *see also*, Staff's initial brief, pp. 154-155.

In rebuttal, DTE Electric states that it appreciates GLREA's proposed pilots and that the company will keep them in mind for potential future pilot opportunities. Additionally, DTE Electric disagrees with GLREA's proposal to create opportunities for third-party aggregators to conduct the pilots, arguing that such action would be a violation of the Commission's decision in Case No. U-21099. 6 Tr 2718; *see also*, December 21, 2022 order in Case No. U-21099 (December 21 order), p. 34. GLREA replies that DTE Electric failed to respond to its proposal, that it disagrees with the company's assertion that the use of third-party aggregator is prohibited by the December 21 order, and that none of the Staff's concerns justify rejection of GLREA's proposals. GLREA's initial brief, pp. 14-15; *see also*, GLREA's reply brief, p. 5.

The Commission is not persuaded that DTE Electric should be directed to create a CP rebate pilot program or GIWH DR pilot program at this time. The Commission, however, encourages DTE Electric to continue to evaluate and explore future potential pilots as appropriate.

ii. Virtual Power Plant Pilot/Demonstration

The CEOs assert that utilities use virtual power plants (VPPs) to, among other things, alleviate overloaded distribution systems, build resilience, and avoid renewables curtailments. 6 Tr 3260. The CEOs, in turn, recommend that the Commission require DTE Electric to work with the Staff and interested persons "to design a VPP pilot/demonstration for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP." 6 Tr 3261; CEOs' initial brief, p. 34.

In rebuttal, DTE Electric states that it appreciates the CEOs' recommendation for an additional VPP pilot, but that DR aggregation by a third party at the residential level is currently banned in Michigan. 6 Tr 2719. Further, the company argues that the pilot is unnecessary given that DTE Electric already offers an array of DR offerings. 6 Tr 2719; DTE Electric's initial brief,

p. 175. The CEOs reply that DTE Electric misinterprets the scope of their proposal to only include DR aggregation for residential customers, which is not the case, and that the proposed pilot fits directly with the Commission's commitment to studying and deploying DERs and other technologies to benefit the grid. CEOs' reply brief, p. 9.

The Commission declines to adopt the CEOs' proposal at this time. The Commission, however, and as previously mentioned, encourages DTE Electric to continue to evaluate and explore ways to maximize value and efficiency of the distribution system and to propose future pilots that more fully capture the potential of DR as appropriate, including, where appropriate, pilots proposed through the expedited pilot process established in Case No. U-20898.

iii. Cost-Effectiveness of Demand Response Programs

The Staff recommends that the Commission require DTE Electric, in its next DR reconciliation or rate case, to expand the company's analysis of the cost effectiveness of its DR programs to include all DR programs, as well as interruptible rates. 6 Tr 5076; *see also*, Staff's initial brief, p. 155-156. The Staff states that it would like to see the company's current cost effectiveness analysis included in DR reconciliation cases to be expanded to all DR programs, and that this analysis should evaluate each program and/or rate individually to compare the cost and benefits of the programs. 6 Tr 5077. GLREA agrees with the Staff's proposal. GLREA's reply brief, p. 3.

DTE Electric supports and agrees with the Staff's proposal to expand the company's cost effectiveness analysis to include all DR programs, including DR tariffs. 6 Tr 2722; DTE Electric's initial brief, p. 175. The company, however, argues that discussion of this analysis should remain in DR reconciliation cases only, which are dedicated to DR issues. 6 Tr 2722. The Staff replies that it is not necessarily opposed to keeping cost effectiveness analyses to DR reconciliations should the three-phased regulatory framework continue in its current form; however, if significant changes occur to this process, the Staff argues that these analyses will need to be included in future rate cases. Staff's initial brief, pp. 155-156.

The Commission finds that DTE Electric has agreed with the Staff's proposal and, therefore, directs the company to expand the company's cost effectiveness analysis to all DR programs, including interruptible rates. Given that the three-phase approach to DR reconciliations remains in place at this time, the Commission finds that it is appropriate to require DTE Electric to include the company's analysis in its next DR reconciliation case.

7. Information Technology

DTE Electric indicates that its IT investment spending is part of its five-year IT plan. The company reports 2022 IT capital expenditures of $224.3 million, projects bridge period IT capital expenditures of $314.6 million, and projects test year IT capital expenditures of $145.7 million. Exhibit A-12, Schedule B5.7. The company indicates that its IT investments are organized into eight IT portfolios as follows: (1) corporate applications, (2) customer service (sustainment and return-to-health), (3) plant and field, (4) IT for IT, (5) information protection security, (6) infrastructure operations, (7) enterprise data analytics, and (8) innovations. 6 Tr 2036. DTE Electric further states the expenditures span the major investment categories of regulatory/compliance, sustainment, return-to-health, IT enhancements, and strategic. *See*, 6 Tr 2033-2036.

The Commission addresses the contested issues within IT individually below.

a. Recommendations by the Commission Staff

i. Information Technology Projects with Level 2 Cost Estimates

The Staff proposes a 20% capital expense disallowance relating to 102 IT projects with a Level 2 cost estimate. 6 Tr 5112; *see also*, Exhibit S-15.2. The Staff indicates its proposed disallowance for "IT projects with Level 2 cost estimates due to their incomplete, imprecise, and indefinite nature," and further explains that:

> IT projects are given a Level 2 cost estimate more than a year before they are ready for implementation. Additional reviews, final approval, and budget allocation occur after projects are given a Level 2 cost estimate. Many things can happen between the time a project is given a Level 2 cost estimate and the year or more later at the time of execution including a change in scope, a change in schedule, the quote from the vendor, prioritization within the APC [Annual Planning Cycle], or the necessity of the project altogether. These examples show the uncertainty of the costs associated with IT projects with Level 2 cost estimates. It is unfair to pass such uncertain expenses onto ratepayers.

6 Tr 5112-5113. The Staff states that it utilized the AACE International Recommended Practice Cost Estimation Classification to establish a class of cost estimate. Citing Case No. U-20863, the Staff claims that the company's "Level 2 cost estimates are based on labor hours, hardware costs, and software costs, but do not have a defined scope," which the Staff indicates "best applies to the AACE Class 3 estimate, with semi-detailed unit costs." 6 Tr 5114. The Staff, therefore, avers that a 20% disallowance is a conservative adjustment and supported by the AACE Class 3 estimates which has a lower bound of -20%. 6 Tr 5114-5115. Additionally, the Staff indicates that the Commission has approved similar disallowances in Case Nos. U-20836 and U-21297. 6 Tr 5115-5116.

DTE Electric disputes the Staff's proposed disallowance. The company states that:

> the Level 2 projects were subject to and have obtained comprehensive review through the APC process. The projects have secured approval in the financial base plan from the Technology Investment Committee. The Level 2 cost estimates are also comprehensive by cost type and phase (where applicable to the project) and

> have been supported by the IT architecture team. IT business case costs are estimated as part of a rigorous APC process where detailed estimates (Level 2) are developed, which include labor, software, hardware, and vendor/consulting costs. At project execution, the Level 2 estimates are further vetted and refined before transitioning to Level 3 estimates.

DTE Electric's initial brief, p. 181 (citing 6 Tr 2169). DTE Electric also contends that, even if a blanket disallowance is appropriate, the Staff's recommendation "fails to consider that the AACE Class 3 estimates also provide an upper range for Class 3 estimates at +30%" and that "it is more accurate to compare Level 2 estimates to AACE Class 2 estimates." 6 Tr 2166.

The Commission finds that the Staff's disallowance is reasonable and supported on this record. As noted by the Staff, the Commission has previously adopted the Staff's recommendation with regard to Level 2 cost estimates. Specifically, in the November 18 order, the Commission held:

> [t]he cost variances pointed out by the Staff and the ALJ are telling. Regardless of whether costs are for projects that are similar to earlier projects, it is still necessary to have a clear understanding of the timing of the project and a level of detail regarding the costs that demonstrates that the costs are reasonable and prudent—without that, the costs cannot be properly evaluated by the Commission for inclusion in rate base and the projections are incomplete. The Commission also finds it appropriate that the Staff recommends adjustments to individual projects rather than to a budget as a whole. That is the only way to determine whether a project presents benefits to ratepayers. The Commission's determination of reasonableness and prudency (and its obligation to protect ratepayers) involves more than the simple hope that the over- and under-projections balance one another out. MCL 460.6; MCL 460.6a.

November 18 order, p. 192. Similarly, in the December 1 order, the Commission noted its agreement with the Staff's proposed disallowance and that:

> [t]he Commission further agrees with the Staff that "Level 2 cost estimates are incomplete and indefinite in nature." The Commission also finds persuasive the Staff's rationale for using the AACE Class 3 Estimate to derive its 20% disallowance here, and as acknowledged by the Staff, "[i]f the Company spends more than 80% of the projected cost, it can include the updated information in the next electric rate case to be reviewed for reasonableness and prudency."

December 1 order, p. 147 (internal citations omitted).

The Commission finds that the Staff's proposed disallowance in the instant case is similarly supported. As previously stated, the use of the AACE Class 3 estimate is reasonable and the company may provide updated information in its next rate case if its spending exceeds 80% of the projected cost. Therefore, the Commission adopts the Staff's 20% capital expense disallowance relating to IT projects with a Level 2 cost estimate.

ii. Information Technology Projects with Level 3 Cost Estimates

The Staff also proposes a 10% capital expense disallowance relating to 104 IT projects with a Level 3 cost estimate. 6 Tr 5116-5117; *see also*, Exhibit S-15.5. The Staff indicates that its proposed disallowance of the Level 3 cost estimates reflects ongoing uncertainty as to the final costs of these projects. The Staff compares the Level 3 cost estimates from Case No. U-21297 with actual costs provided in this case, and "found that the percent difference of the costs ranged from -100% to 1269%." 6 Tr 5117 (citing Exhibit S-15.6). The Staff further indicates that:

> [a]ccording to the Company, Level 3 cost estimates are the most accurate cost estimate prior to actual costs; however, Staff's analysis demonstrates a significant discrepancy. The cost variance between Level 3 cost estimates and actual costs are not much more improved than the cost variance between Level 2 cost estimates and Level 3 cost estimates. Once again Staff emphasizes that the Company chooses to file a projected test year in its rate case application and has an obligation to make accurate expense requests. As projected, the Company may over recover costs for these IT projects, but the Commission is unable to perform retroactive ratemaking to correct for this issue. It is unfair to pass costs onto ratepayers without the assurance that its entirety will be used for the intended reasonable and prudent investment. If the Company spends more than 90% of the requested cost, they can always seek recovery in the next rate case.

6 Tr 5118.

Similar to the proposed Level 2 cost estimate disallowance, the Staff explains that it utilized the AACE International Recommended Practice Cost Estimation Classification to establish a class of cost estimate. Based upon this, the Staff states that the AACE Class 1 estimate best applies which has a lower bound of -10%, and as such, the Staff's proposed "10% is a generous adjustment as the average percent over recovery exceeds 30%." 6 Tr 5119.

DTE Electric responds that the Staff's methodology does not support the proposed blanket disallowance. Specifically, the company claims that Staff's Exhibit S-15.6 "provides only a partial view of total project costs and should not be the determining factor for a blanket 10% disallowance for all Level 3 projects." 6 Tr 2170. Rather, DTE Electric contends that:

> the total costs approved for cost recovery in Case No. U-21297 should be compared to costs submitted as part of this Case No. U-21534 within the 36 months ending December 31, 2024. The Company did so for all 70 projects identified as overrecovered in Exhibit S-15.6, showing that 49 were within the variance specification allowance, so they should not be considered as part of the over-recovery (Sharma, 6T 2170-71; Exhibit A-46, Schedule KK4).
>
> The Company also explained why variances greater than 20% occurred for 13 projects. Some of the variances were a result of efficiency gained during project planning and execution, which should not be held against the Company, so these projects should also not be used for blanket disallowance.

DTE Electric's initial brief, p. 182 (footnote omitted).

Similar to the Level 2 cost estimate disallowance discussed previously, the Commission finds that the Staff has supported its Level 3 cost estimate disallowance. As noted by the Staff, its analysis demonstrates that the Level 3 cost estimates continue to be refined, contrary to DTE Electric's contentions. The Commission is not persuaded by the company's claims that the disallowance should be rejected because of a reduction in expense due to efficiency gained during the project execution. The Commission further agrees with the Staff that it is "unfair to pass costs onto ratepayers without the assurance that its entirety will be used for the intended reasonable and prudent investment." 6 Tr 5118. Moreover, if DTE Electric's actual spend exceeds 90% of the requested cost as approved by this order, the company may seek recovery its next general rate case for the actual spend. Therefore, the Commission adopts the Staff's 10% capital expense disallowance relating to IT projects with a Level 3 cost estimate.

iii. Digital Worker Experience Electric End of Life

The Staff proposed a disallowance relating to company-owned endpoint devices (i.e., desktop computers, laptops, tables, smart devices, and ruggedized field computers). 6 Tr 5120-5121. DTE Electric disputes the proposed disallowance, arguing that the Staff's calculation does not reflect "the labor costs required for configuration, deployment, and testing of the devices." 6 Tr 2173-2174. In its initial brief, the Staff agrees that labor costs should be accounted for and updates its recommendation which:

> takes the Projected Capital Labor Costs, Projected Capital Non-Labor (Contractor) Costs, and the Projected Overhead & Other Costs into account. Staff's recommended disallowance of $0.3 million in the bridge period ($137,268 in 2023 and $162,309 in 2024) and $246,962 in the 2025 test year is due to the difference between the Projected Capital Non-Labor (Material) Costs forecasted in Exhibit A-24 N3 and the actual material expense calculated using the number of devices replaced as stated by the Company in direct testimony and the actual cost of the devices provided through audit. The Company has not supported these remaining dollars in any exhibit or testimony; therefore, it is unreasonable and imprudent to allow the complete projected cost of the Digital Worker Experience EOL [End-of-Life] project to be included in rates.

Staff's initial brief, pp. 53-54. In its reply brief, the company states that it "appreciates and accepts Staff's updated position." DTE Electric's reply brief, p. 61.

The Commission finds that, given the company's acceptance of the Staff's updated recommendation, the Staff's recommended disallowance of $0.3 million in the bridge period ($137,268 in 2023 and $162,309 in 2024) and $246,962 in the 2025 test year for the Digital Worker Experience Electric EOL project is adopted.

b. Recommendations by the Attorney General

i. Customer Service Projects

The Attorney General proposes disallowances of $5.75 million for 2024, and $15.393 million for 2025, relating to four customer service IT projects. 6 Tr 3630-3631. She indicates that the company included these four projects in capital expenditures for 2024 and 2025, even though the projects are either in the early phase of development or work has yet to be started. The Attorney General states that the four disputed projects are:

> (1) the MIGP [MIGreenPower] Customer Requested Renewable Energy Project, which will not kick-off until August 2024; (2) the MIGP Scope Billing and Enrollment project, which will not be completed until 2026; (3) the Rider 17-MIGreenPower Residential and Commercial projects, which are still in the early design phase or will not kick-off until 2025; and (4) the 2025 Advance Analytics Use Cases for Reducing [Commission] Complaints, which will not start until March 2025.

6 Tr 3630 (citing Exhibit AG-13).

In response, the company states that the Attorney General's proposed disallowance is overstated as it includes additional projects that are not specifically identified by the Attorney General for disallowance. 6 Tr 2306-2307. DTE Electric does not dispute the recommended disallowance associated with the MIGP Scope 3 Billing and Enrollment project because the project was rescheduled to begin in 2026. 6 Tr 2308. The remaining three disputed projects are addressed below.

DTE Electric disagrees with the proposed disallowance for the MIGP Customer – Requested Renewable Energy Projects (Exhibit A-12, Schedule B5.7.3, line 4), noting that the capital requested in this case "reflects a variance of $4.6 million less in the 36 months ending December 31, 2024, than what was approved for cost recovery in [Case No.] U-21297 as the project has been pushed out to 2025 due to a delay in the construction of these projects."

6 Tr 2308. The company further argues that the project received prior approval in Case No. U-21297 and represents two unique contracts which DTE Electric is bound by. Further, DTE Electric states that the "project kicked-off on August 1, 2024, is in the project initiation phase and progressing per the timetable provided on page 5 of Exhibit AG-13, and is on track to go-live by November 30, 2025." 6 Tr 2309.

With respect to the Attorney General's recommended disallowance for the Rider 17 – MIGP, residential and small C&I project (Exhibit A-12, Schedule B5.7.3, Line 15), the company states that the planned work could not begin until the project was approved by the Commission in November 2023. Again, DTE Electric argues that due to "the regulatory nature of this project and the prior approval of the project capital in Case No. U-21297 as a Level 2 project . . ., the Company is mandated and committed to make these investments" and the proposed disallowance should be rejected. 6 Tr 2310. The company further states that recovery is not premature because the project kicked-off in February 2024 and because it "is essentially one multi-year project with annual releases of system enhancements" and as such, "is well beyond the initial design or early development stage of maturity." 6 Tr 2310.

DTE Electric contends that the proposed disallowance for the Advanced Analytics Use Case for reducing complaints (Exhibit A-12, Schedule B5.7.3, line 18) should be similarly rejected. The company specifically states that, consistent with Exhibit AG-13, the project is on track to start in March of 2025, and that there is no modification to the go-live date. DTE Electric states that initial scoping was completed "and data preparation to bring complaints data into our DTE cloud platform is underway. Due to the extensive data and data engineering requirements of the project, work has begun in 2024 to ensure the timely kick-off of the modeling phase of the project in March 2025." 6 Tr 2311-2312.

The Attorney General responds that the proposed disallowance for the projects is not overstated and that the discovery responses confirm the testimony that recovery for the projects is premature. Attorney General's reply brief, p. 27 (citing to Attorney General's initial brief, pp. 36-37).

The Commission is not persuaded that recovery for the remaining three projects is premature. The company has demonstrated that, although some delays have occurred, the projects have progressed and are on track with the company's projected timelines. *See*, 6 Tr 2308-2311. Therefore, the Commission rejects the Attorney General's proposed disallowances for customer service IT projects excluding the company's conceded disallowance for the MIGP Scope 3 Billing and Enrollment project (Exhibit A-12, Schedule B5.7.3, line 11). *See*, 6 Tr 2308.

ii. Enhanced Document Management Capability Projects

The Attorney General also proposes disallowances for the company's proposed Cloud Health and Safety project and the Enhanced Document Management Capability projects. The Attorney General argues that the company failed to provide all requested information in response to a discovery request. The Attorney General avers that due to the lack of information on record, "it is not possible to determine what phase those projects are currently in or whether they will be completed by the end of the projected test year and be used and useful." 6 Tr 3632. In response, DTE Electric contends that due to confusion in the wording of the request, the requested information was provided, and that the intended information was ultimately provided in Exhibit A-46, Schedule KK2 upon rebuttal. 6 Tr 2176-2178; *see also*, Exhibit A-46, Schedule KK2.

The Commission once again is not persuaded that recovery for the enhanced document management capability project is unsupported on the record or premature. DTE Electric explained that the information was not originally provided based upon a misalignment between the Attorney General's discovery request and the company's testimony. *See*, 6 Tr 2176-2178. The Commission agrees and finds that the Attorney General's discovery request was not dismissed. Further, the company sponsored Exhibit A-46, Schedule KK2 ultimately providing the information that was requested by the Attorney General. DTE Electric described the projects in testimony, including the timeline for the projected expenditures. 6 Tr 2047-2048, 2050-2051. Therefore, the Commission finds that the record supports the projects and recovery is not premature.

c. Recommendations by the Detroit Area Advocacy Organizations

The DAAOs raised many objections and concerns regarding DTE Electric's IT capital expenditures. Specifically, the DAAOs raise concerns regarding minimal evidence in support of the proposed investments, which exacerbate poor customer service and cause additional harm to low-income and vulnerable customers. *See*, DAAOs' initial brief, pp. 56-68. The DAAOs specifically recommend a $10.7 million disallowance for the Collections Digital Self-service platform.

With regard to digital self-service investments, the DAAOs indicate that DTE Electric may see diminishing returns and note that the investments may not generate the benefits the company claims. The DAAOs further state that DTE Electric's own testimony suggests that the company may be reaching a saturation point and claim that the proposed IT investments may not be aligned with the broader goals of the Commission. *See*, 6 Tr 4398-4399. The DAAOs contend that the company's justification for the investment "reveals a troubling misalignment of incentives that prioritizes the company's own financial interests over the needs and well-being of its customers." 6 Tr 4400. More specifically, the DAAOs indicate that:

> rather than proposing meaningful solutions or investments to address these challenges and reduce the need for collections activities in the first place, DTE

> Electric is instead seeking to use ratepayer funds to make its collections process more automated, efficient, and aggressive. This reveals a perverse incentive structure in which DTE Electric is essentially being rewarded for its own failure to ensure that its services are affordable and accessible to all customers. By investing in digital self-service tools and other technologies that make it easier and cheaper for the company to pursue collections and disconnections, DTE Electric is effectively shifting the costs and risks of its own unaffordable rates onto its most vulnerable customers, while generating additional profits for its shareholders through increased capital spending.

6 Tr 4401. Acknowledging there may be benefits to customers in improving digital self-service, the DAAOs propose that the company be required "to provide a more detailed and comprehensive cost-benefit analysis of its IT investments, including specific metrics and targets for reducing energy burdens, preventing disconnections, and improving customer satisfaction and affordability, particularly for low-income and vulnerable households." 6 Tr 4402.

DTE Electric disputes the DAAOs' proposed disallowance, claiming that none of the concerns have merit. With respect to potential diminishing returns, the company alleges that it forecasts reducing total call volume will provide substantial cumulative net O&M savings through 2027. 6 Tr 2204-2208; *see also*, Exhibit A-24, Schedule N5. While the company acknowledges that the digital engagement rate for outages and payments are each near the 2027 goal, DTE Electric contends that outage digital engagement rate varies based on volume of storm activity and that a 1% increase in payment digital engagement rate by 2027 is ambitious. 6 Tr 2315. Overall, the company disputes the proposed disallowance and states that it "maintains that its Collection Digital Self-Service investments are beneficial to customers, satisfy the needs of customers who choose to engage in a digital self-service solution, and provide substantial savings that are passed on to all customers through the rate-making process." 6 Tr 2322.

The Commission agrees with the DAAOs that the company has not demonstrated that its proposed investment in digital self-service is reasonable and prudent. More specifically, DTE

Electric again provided forecasted projections of reductions of call volumes without additional support for its forecast. The company acknowledges that actual collection call volumes are not materially different despite previous investments. 6 Tr 2207. The Commission is not persuaded by DTE Electric's claims that increased call volume "was mitigated by a reduction in the number of calls from customers who chose to use a digital solution to restore service, to enroll in a payment agreement, or to check on the status of an account hold." 6 Tr 2207. Moreover, the record demonstrates that, despite prior investments, collections digital engagement rates are the lowest of any type of transaction. Without additional data, the Commission is not convinced that the proposed investment is reasonable. As stated by the DAAOs, the record "points to the reality that DTE customers navigating Collections issues continue to need phone-based service to resolve these issues and they are not adopting Collections digital solutions at as high rates." DAAOs' initial brief, p. 63. Overall, the Commission finds that the company's proposed $10.7 million investment in Collections digital self-service platform is not supported on this record.

8. Corporate Staff Group

DTE Electric reports 2022 Corporate Staff Group (CSG) capital spending of $126.6 million for 2022, projects bridge period CSG expenditures of $235.8 million, and projects test year expenditures of $120.1 million. 6 Tr 1521; Exhibit A-12, Schedule B5.8. The company organized the projects into the following categories: (1) EV Fleet; (2) Facilities-Construction & Upgrade; (3) Service Center Optimization and Modernization; (4) Security Measures; and (5) Other Miscellaneous. *See*, 6 Tr 1521-1527. The disputed capital expenditures are discussed individually below.

a. Recommendations by the Commission Staff

The Staff proposed a reduction in CSG capital expenditures categorized as "Other Miscellaneous" given the spending is not for specified work that can be reviewed for reasonableness and prudence. *See*, Staff's initial brief, p. 63. Specifically, the Staff states that it recommends:

> a disallowance of $720,000 to the Company's projected 2024 and 2025 capital expenditures because this is the amount that the Company has identified is being projected for emergent spend for a project for underground storage tank removal and cleanup. . . . Staff recommends the Commission disallow the expenditures included in the Company's projection for emergent spend because it is not for any specific work at this time. These expenditures may not incur in full, if at all, and the Commission cannot perform retroactive ratemaking to correct rates, should that be the case. It is not reasonable to pass these expenditures onto customers at this time, because they cannot be judged for their reasonableness and prudence.

6 Tr 5096 (internal citations omitted). DTE Electric generally responds that its proposed CSG spending is "reasonable, prudent, and should be approved." DTE Electric's initial brief, p. 193.

The Commission agrees with the Staff. Given the lack of specificity and uncertainty regarding the potential spending, the Commission cannot review the proposed expenditures and approval of such is not reasonable and prudent on this record. As such, the Staff's proposed disallowance for CSG capital expenditures classified as "Other Miscellaneous" is adopted.

b. Recommendations by the Michigan Department of Attorney General

The Attorney General recommends:

> 1) that the Commission remove $6,265,000 for 2023 and $8,000,000 for 2024 from the capital expenditures forecasted by the Company for renovations at DTE's headquarters, 2) remove $24,600,000 from the Company's forecasted capital expenditures for 2025 related to the 9 projects in early stages of development, and 3) remove $4,564,000 for 2024 and $8,187,000 for 2025 related to DTE's transportation fleet.

Attorney General's initial brief, p. 40.

i. Facilities Construction and Upgrades

With regard to the corporate headquarters, the Attorney General contends that in response to discovery requests DTE Electric provided "no clear answers to the questions, pointing simply to company policy decisions and the need for developing agile work space and reconfiguring office furniture." 6 Tr 3634. Further, the Attorney General argues that the company's responses that employees need equipment both at home and the office is not persuasive and demonstrates wasteful spending. DTE Electric responds that it did provide clear responses to the Attorney General's discovery requests and described the company's rationale for the costs. Specifically, the company states that it has:

> reduced its total office space by selling buildings and terminating leases and then had to increase the number of workstations within that smaller space to accommodate employees returning to the office after the pandemic. [The company] moved from 2,000 reservable workstations to 4,100 workstations assigned to each employee. Additional technology was required to enable more video conferencing for employees in the office with employees working remotely. Equipment was added as needed and meeting space was optimized. The conversion of the open space in the downtown Detroit headquarters lobby was to accommodate large groups that previously used leased space or facilities the Company no longer owns.

6 Tr 1567.

The Commission finds that the company has supported its request with regard to the renovations to its corporate headquarters. Contrary to the Attorney General's claims, DTE Electric did provide responses and further explained the expenditures. Therefore, the Attorney General's recommendation to remove \$6.265 million for 2023 and \$8 million for 2024 from the capital expenditures forecasted, is rejected.

Regarding the Attorney General's recommendation for projects in the early stages of development, she explains that "[t]he timing and cost can change significantly before project specifications, design, and work begins on those projects. Customers should not run the risk of paying in rates for costs that the Company may not incur" and that for projects that will not be used and useful in 2025, the proposed capital expenditures should be removed from rate base. 6 Tr 3636. DTE Electric responds that "[s]uch disallowances should not have any impact" and that:

> [t]o ensure that is the result, either the proposed disallowances for projects not going into service should be excluded from any reductions to rate base approved by the Commission, or a corresponding adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of the projects from approved rate base.

6 Tr 1567-1568.

As previously discussed, the Commission is not persuaded to reject programs and projects for inclusion in rate base solely on the basis of their in-service date, and nothing in the evidentiary record regarding strategic capital convinces the Commission to alter that finding. The Commission rejects this proposal for the reasons articulated above including in Part V, Section B.3.b.i. of this order.

ii. Vehicle Fleet Expenditures

The Attorney General also proposed a disallowance of $4.564 million for 2024, and $8.187 million for 2025 relating to the company's proposed vehicle fleet expenditures. 6 Tr 3636-3637. The Attorney General explains that DTE Electric failed to provide adequate information to support its request and "[g]iven this lack of information, a reasonable approach to forecast capital expenditures in this area is to use the average capital spending during the most recent three years and adjust that amount for forecasted inflation in 2024 and 2025." 6 Tr 3637. Initially, the Staff also recommended an adjustment to the company's vehicle fleet capital expenditures but withdrew that position in support of DTE Electric's expenditures. 6 Tr 5135; Staff's initial brief, p. 43.

DTE Electric responds to the Attorney General's recommendation and the Staff's initial recommendation, indicating that in response to the Staff's discovery request and in Exhibit A-37, Schedule BB2, it provided the company's specific vehicle purchase plans for 2025. DTE Electric further explains that it "uses a life-cycle model to optimize the total cost of ownership and develop a replacement strategy," which it claims "is a more reasonable forecast methodology than the simplistic historical average used by [the Attorney General]." 6 Tr 1564-1565. Similarly, in briefing, the Staff indicates that the company has rebutted the Attorney General's disallowance. Staff's initial brief, pp. 43-44 (citing 6 Tr 1564-1565).

The Commission finds that the company has provided support for its vehicle fleet capital expenditures. More specifically, as noted by both DTE Electric and the Staff, the company provided information regarding its specific vehicle purchase plans in response to the Staff's discovery request. 6 Tr 1564-1565; *see also*, Exhibit A-37, Schedule BB2. This is a more accurate method for forecasting spending on the company's vehicle fleet, therefore, the Attorney General's proposed disallowance is rejected.

C. Working Capital Balance and Total Rate Base

Based on the decisions in this order, the Commission finds that DTE Electric has a working capital balance of $1,279,873,000 and a projected rate base of $21,787,037,000.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

DTE Electric proposes maintaining its balanced capital structure of 50% debt to 50% equity. 6 Tr 2548; *see also*, Exhibit A-14, Schedule D1. The Staff did not recommend any adjustment to the company's proposal. 6 Tr 5009-5010. Similarly, the Attorney General also recommended adoption of a 50/50 capital structure. 6 Tr 3656; *see also*, Exhibit AG-26.

The Commission finds there is no dispute on the record regarding the proposed capital structure of 50% debt to 50% equity. As such, the balanced capital structure as proposed by DTE Electric is adopted.

B. Debt Rates

1. Long-Term Debt Rate

DTE Electric projects a weighted average long-term debt rate of 4.24% for the test year. 6 Tr 2556. The Attorney General agreed with the company. 6 Tr 3657. The Staff, however, recommends a long-term debt rate of 4.21%. 6 Tr 5011. The Staff explains that the differences in its proposed rates "are due to Staff updating the Company's now historic debt issuances and projected interest rates on the bonds to be issued in 2025." 6 Tr 5011-5012. The company disagrees with the Staff, arguing that "[w]ith these updated projected 2025 issuances and actual 2024 issuances, the weighted average long-term debt cost as of December 31, 2025 approximates the Company's original 4.24% calculation." DTE Electric's initial brief, p. 195 (citing 6 Tr 2564-2565; Exhibit A-45, Schedule JJ1). The Staff responds that DTE Electric did not, however, provide any testimony to dispute the Staff's calculation, and reiterates that its proposed long-term debt rate of 4.21% is appropriate. Staff's initial brief, p. 66.

The Commission finds that the company's projected long-term debt rate is reasonable and should be adopted. Specifically, the Commission finds that while the Staff's adjustment "is due to Staff using a more recent treasury projection for the new issuances," 6 Tr 5011-12, DTE Electric updated its initial projections during the course of the proceeding, finding that the weighted average long-term debt cost based on actual 2024 issuances and projected 2025 issuances approximates its original calculation of 4.24%. The Commission finds this approach to be more reasonable and is, therefore, adopted. The Commission further finds that the current interest rate environment requires up-to-date data to reflect the most appropriate debt rate under evolving circumstances, and that DTE Electric's approach of using both actual 2024 issuances and projected 2025 issuances is most likely to approximate the actual long-term debt rates at the end of 2025. Finally, the Commission notes that the issue of long-term debt rates has not been contested in recent DTE Electric rate cases, perhaps not surprisingly given the relative stability of the interest rate environment in recent years. This issue was contested, however, in DTE Gas's most recent rate case in Case No. U-21291. In that instance, the administrative law judge ultimately found persuasive the same methodology that DTE Electric employs here. Notably, the Staff did not file exceptions on this issue in the DTE Gas case, and the Commission ultimately adopted the judge's recommendation and DTE Gas's methodology in the November 7 order. The Commission sees no reason to deviate from this recent precedent in the current proceeding. Therefore, the Commission approves DTE Electric's long-term debt rate of 4.24%.

2. Short-Term Debt Rate

DTE Electric projects a total cost of short-term debt of 5.76%. 6 Tr 2557-2558. As with the long-term debt rate, the Attorney General agreed with the company's projected short-term debt rate. 6 Tr 3657. Again, the Staff recommends updating the company's short-term debt rate with more recent projections and indicates that a short-term debt rate of 4.96% is more appropriate. 6 Tr 5011-5012. In rebuttal, the company revised its projection to 5.73%. 6 Tr 2565. The Staff responds that, "[a]lthough this adjustment is in the direction of Staff's figure, it is still too high" and requests that the Commission approve the Staff's rate of 4.96%. Staff's initial brief, p. 66.

As above, the Commission finds that the company's projected short-term debt rate is reasonable and, therefore, adopts the company's projection. The Commission finds compelling the fact that the actual cost of short-term debt in July 2024, including the company's actual interest rate spread, was 5.48%, and that when the 0.25% cost of credit facility fees is added, the result is an actual short-term debt rate of 5.73%. 6 Tr 2565. Furthermore, while the Staff asserts that DTE Electric's mid-case adjustment "is in the direction of Staff's figure" of 4.96%, the reality is DTE Electric's revised figure is nearly identical to the company's initial projection of 5.76% (just a three basis point adjustment, compared to the 77 basis point difference with the Staff's projection), lending additional credence to the company's methodology and resulting projections. Finally, as noted above, this issue was also raised in DTE Gas Company's most recent rate case, in Case No. U-21291. As with the long-term debt rate, the Commission adopted the administrative law judge's recommendation in that case which ultimately sided with the company, and the Staff also chose not to file exceptions on this issue. As with the long-term debt rate, the Commission sees no reason to deviate from the approach taken less than three months ago on a nearly identical fact pattern. Therefore, the Commission approves the short-term debt rate of 5.73%.

C. Return on Equity

The criteria for establishing a fair ROE for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679; 43 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). The Supreme Court has made clear that, in establishing a fair ROE, consideration should be given to both a utility's investors and its customers. Nevertheless, the determination of what is fair or reasonable "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." *Meridian Twp v City of East Lansing,* 342 Mich 734, 749; 71 NW2d 234 (1955). With these principles in mind, the Commission turns to the factors that form the basis for determining the ROE for the company.

DTE Electric, the Staff, the Attorney General, ABATE, and CUB each offered analyses of the appropriate ROE. DTE Electric requests an ROE of 10.5%, the Staff recommends an ROE of 9.9%, the Attorney General advances an ROE of 9.85%, ABATE suggests an ROE of 9.6%, and MNSC recommends an ROE of 9.3%. These parties' analyses are addressed more below. In addition, Ann Arbor contends that, based upon a review of prior authorized ROEs and credit ratings, the Commission should adopt a lower ROE than currently authorized "to send a meaningful notice to DTE that until it starts improving reliability, it will not be able to earn as high a rate of return." 6 Tr 4526; *see also*, 6 Tr 4252-4255. Walmart indicates that the company's requested ROE is excessive and that in reviewing average authorized ROEs, the Commission should carefully examine the proposed revenue requirement and ROE in making its determination. *See*, 6 Tr 4727-4734. Relying upon the Attorney General's analysis, the DAAOs suggest that the Commission should adopt an ROE of 9.18%. 6 Tr 4439-4440.

As noted above, DTE Electric requests an ROE of 10.5% relying upon: (1) the capital asset pricing model (CAPM), (2) an empirical CAPM (ECAPM), (3) the single-stage and multi-stage discounted cash flow (DCF) models, and (4) the risk premium model. 6 Tr 2414-2415. The company explains that it selected a proxy group of 25 publicly traded regulated utility companies meeting various screening criteria. 6 Tr 2428-2430. DTE Electric indicates that "[t]o reflect the effect of capital structure on the cost of equity, [the company] adjust[s] the cost of equity estimates [obtained] from applying the models to the market data of the proxy companies." 6 Tr 2432.

The company first describes its CAPM and ECAPM approaches. 6 Tr 2433-2436. DTE Electric notes that "there is very little difference between the CAPM and ECAPM results at this point in time" and that the "results are consistent with a cost of equity in the range of 10.75 percent to 11.75 percent (rounding to the nearest ¼ percent)." 6 Tr 2436. Next, the company summarizes its DCF model approaches. 6 Tr 2436-2439. DTE Electric indicates that "[t]he range of estimates obtained from the DCF methods range from 9.4 percent to 11.2 percent (9.5% to 11.25% rounding to the nearest ¼ percent)." 6 Tr 2439. However, the company contends that the multi-stage results are not representative and as such, DTE Electric considers the narrower range of 10.0% to 11.0% for the electric sample to be more appropriate. 6 Tr 2439.

Finally, DTE Electric describes its risk premium approach. 6 Tr 2439-2441. The company indicates that its estimated ROE for electric utilities is 10.5% under this approach. 6 Tr 2441. In Figure 13, DTE Electric summarizes the results from each approach and notes that "[t]he average of the low and high is 10.2 percent and 11.1 percent, respectively with the reasonable range being close at approximately 10.25 to 11.0 percent for the electric sample." 6 Tr 2442. Thus, the company avers that its requested ROE of 10.5% falls below this midpoint and is a conservative estimate considering DTE Electric's specific risk profile. *See*, 6 Tr 2442-2446.

The Staff set forth 9.30% to 10.30% as a reasonable ROE range, with a recommended 9.90% ROE. 6 Tr 5013. The Staff first reviews precedent of landmark cases considered in conducting its analysis, noting that it utilizes the DCF, CAPM, and risk premium models and reviews recent electric ROE determinations from other jurisdictions. 6 Tr 5013-5014. Next, the Staff indicates that it used a proxy group of 13 electric companies meeting six criteria and that its proxies overlap with those used by DTE Electric, but that the Staff's criteria were generally more restrictive. 6 Tr 5015.

Describing its DCF analysis, the Staff sets forth an average adjusted DCF estimate of 9.78% and a median estimate of 9.71%. 6 Tr 5016-5018; *see also*, Exhibit S-4, Schedule D-5. The Staff also responds to the company's DCF estimate, which the Staff indicates utilizes "a version of the After-Tax Weighted Average Cost of Capital (ATWACC) approach which has never been approved by this Commission" and the Staff does not believe should be utilized in determining an ROE in a utility rate case. 6 Tr 5018-5019. The Staff next describes its CAPM model. 6 Tr 5019-5022; *see also*, Exhibit S-4, Schedule D5. The Staff indicates that it "computes an average CAPM cost of equity of 10.23%, and a median of 10.31%" which it contends is a high-end estimate because beta values for the utility sector are abnormally high. 6 Tr 5021. The Staff also avers that it "does not believe it is appropriate to make an adjustment for equity ratio of the proxy companies in a ratemaking environment," and that it "also disagrees with the use of the ECAPM in conjunction with adjusted betas for the purposes of determining a reasonable ROE." 6 Tr 5022.

The Staff then outlines its risk premium analysis and indicates that it "gives an estimate of 10.05% using the A-rated utility bond method and 8.63% using the Treasury bond method." 6 Tr 5024-5025. The Staff notes its disagreement with the company's use of the regression analysis risk premium model, noting a preference for the more traditional risk premium model. 6 Tr 5025. The Staff also indicates that it reviewed the ROEs for electric utilities as authorized by other state commissions. This reflects an average authorized ROE of 9.60% for 2023, and an average ROE of 9.66% in 2024. 6 Tr 5025. Overall, the Staff concludes that a reasonable ROE range based upon its analysis is 9.30%-10.30%, with 9.90% being appropriate for DTE Electric in this case. 6 Tr 5026.

The Attorney General recommends the adoption of an ROE of 9.85%. 6 Tr 3657. The Attorney General first reviews the general principles considered in making her ROE recommendation and states that she uses the DCF method, the CAPM, and the Utility Risk Premium approach in deriving her recommendation. 6 Tr 3658-3659. In developing an appropriate proxy group, the Attorney General notes that her analysis began with 38 electric utilities which was narrowed down to 10 companies considered comparable to DTE Electric. 6 Tr 3660-3661; *see also*, Exhibits AG-33. AG-28, and AG-29. The Attorney General indicates that eight of her proxy companies overlap with DTE Electric's proxy group, and that many of the additional companies utilized by DTE Electric "have extraordinary and unique risks or uncertainties and should not be included in the group of peer companies." 6 Tr 3662.

The Attorney General continues and describes her DCF approach. 6 Tr 3663-3664. The Attorney General notes that her analysis results in "an average required return on common equity of 9.26% for the proxy group." 6 Tr 3664. Next, the Attorney General compares her DCF approach to the company's DCF approach, explaining that part of the discrepancy between the two is due to the proxy group selection. 6 Tr 3664-3666. Further, the Attorney General states that the company's use of financial leverage adjustments or ATWACC approach also inflates the company's DCF calculations. *See*, 6 Tr 3666-3668.

The Attorney General then describes her CAPM approach. 6 Tr 3669-3671. The Attorney General determined an estimated 10.57% ROE under the CAPM approach, but she notes that the CAPM approach is given less weight in her determination given the effects of beta and the fluctuations of the overall market. 6 Tr 3671-3673. Similar to the Staff's criticisms of the company's DCF approach, the Attorney General indicates that DTE Electric's approaches utilize the leveraged betas which, like the ATWACC, leads "to faulty and inflated results." 6 Tr 3671. Finally, the Attorney General discusses the utility risk premium approach. 6 Tr 3673-3676. The Attorney General indicates that her utility risk premium approach reflects an ROE of 10.1%. 6 Tr 3673. She indicates that the company's methodology is not a traditional risk premium analysis and asserts that it contains several flaws. 6 Tr 3674.

Similar to the Staff, the Attorney General also reviews ROEs authorized by other regulatory commissions. 6 Tr 3676-3677. The Attorney General indicates that “the overall average ROE rate was 9.54% in 2022 and 9.66% in 2023,” which demonstrates that DTE Electric’s authorized ROE is “considerably higher than the equity returns granted by state regulatory agencies for most other electric utilities.” 6 Tr 3677. She further argues that her recommended ROE of 9.85% should not have negative effects on the company’s credit ratings or creditworthiness. 6 Tr 3678-3680. As such, the Attorney General recommends that the Commission authorize an ROE of 9.85%. 6 Tr 3681-3683.

ABATE reviews the framework surrounding a regulated utility’s cost of common equity before reviewing factors pertaining to DTE Electric’s overall financial risk. 6 Tr 3441-3446. In developing its proxy group, ABATE notes that it relied upon the same proxy group as DTE Electric. 6 Tr 3447. Next, ABATE indicates that it considered the constant growth DCF model, both with analysts’ growth and sustainable growth, and the multi-stage DCF model. *See*, 6 Tr 3448-3459. ABATE’s DCF models resulted in an average range of 8.90% to 10.51%; however, ABATE contends that greater weight should be given to the sustainable growth and multi-stage models of the DCF, which has a narrower range of 8.90% to 9.03%. 6 Tr 3458-3459.

ABATE continues, describing its risk premium model. 6 Tr 3459-3463. ABATE summarizes its risk premium results as ranging from 9.95% to 10.27%. 6 Tr 3463. With respect to the CAPM method, ABATE first describes its method, including the development of its market risk premium. 6 Tr 3463-3474. ABATE summarizes its CAPM results utilizing the three methods and betas for an overall range of 8.58% to 12.27%. 6 Tr 3474. Based upon each analysis, ABATE concludes that DTE Electric’s ROE should “be in the reasonable range of 9.20% to 10.00%” with a recommendation of 9.60%, the midpoint of the recommended range. 6 Tr 3478.

MNSC indicates that it utilizes the DCF and CAPM analysis to recommend an ROE in this case of 9.30%. 6 Tr 3748-3749; *see also*, Exhibit CUB-8 and 6 Tr 3750-3761. MNSC contends that "[t]he Commission should deny DTE's request to increase its authorized ROE, and should instead lower the Company's ROE to 9.30% or somewhere between that figure and the current authorized figure of 9.90%." MNSC's initial brief, p. 97. Further, MNSC argues that the risk premium model should not be relied upon at all. *See*, *id*., pp. 108-109 (citing 6 Tr 3760 and *Assoc of Bus Advocating Tariff Equity Coalition of MISO Transmission Customers et al v Midcontinent Independent System Operator et al*, 169 FERC ⁋ 61129 (Nov 21, 2019) (FERC Opinion No. 569)).

The company responds to the Staff and intervenors' methodologies, noting that certain modeling choices caused downward bias to their ROE recommendations. *See*, 6 Tr 2493-2501. DTE Electric also claims that all parties recommend higher ROEs than in prior cases, "[t]hus, they all essentially acknowledge that the cost of equity has increased since the Commission maintained DTE Electric's ROE at 9.90% in Case No. U-21297, as well as since the Commission set it previously." DTE Electric's initial brief, p. 197 (citing 6 Tr 2493, 2496). DTE Electric further contends that any "[p]roposals to maintain or lower DTE Electric's ROE are also inappropriate in today's financial environment and considering the Company's business risk." DTE Electric's initial brief, p. 207 (citing 6 Tr 2492-2493).

The Commission has carefully considered the evidence presented by all parties and finds that the Staff's methodology is the most reliable indicator of a reasonable ROE on this record. The Commission finds that DTE Electric's proxy group of 25 companies may be too broad and that the Staff's proxy group of 13 and the Attorney General's proxy group of 10 companies are more reasonable and comparable to DTE Electric. As noted by the Attorney General, if the six companies identified by the Attorney General as inappropriate proxies were excluded, DTE

Electric's DCF ROE estimate would be significantly lower. Specifically, the Attorney General explains that excluding those companies from DTE Electric's DCF analysis would have resulted in an estimated 9.70% ROE rather than the 11.20% as indicated by the company. *See*, 6 Tr 3664-3665.

In addition to potential discrepancies regarding proxy groups, the Commission finds that DTE Electric utilized financial leverage adjustments, which is disputed on this record by the Staff and other parties. *See*, 6 Tr 5018, 6 Tr 3666-3668. In that regard, the Commission finds that it has consistently indicated that adjusting for financial risk is not an appropriate method and, once again, reiterates its conclusion in this case. *See*, December 1 order, p. 186, and November 18 order, p. 241. The Commission has also previously clarified that Commission precedent references significant *changes* in ROE and not only declines in ROE as implied by DTE Electric in this case. *See*, November 18 order, p. 242, n. 34; *see also*, December 1 order, pp. 185-186.

With respect to ROE methodologies, the Commission reiterates that it is not limited to considering methodologies as approved by FERC. As recently held in the November 7 order:

> [t]he Commission agrees that the evidence presented in each case should be considered in arriving at an approved ROE for the utility. As noted in the PFD, the appropriateness of the use of the risk premium model is in flux before FERC and, at this time, the Commission declines to make a bright line rule about the applicability or appropriateness of this, or any one model as a whole. Similarly, the Commission declines to require an additional analysis regarding the risk premium model in the company's next rate case as recommended by the ALJ. The Commission will continue to review the evidence presented by the parties giving appropriate weight and consideration to each methodology presented on each record in each case.

November 7 order, pp. 106-107 (internal citations omitted). Notwithstanding this, the Commission agrees with the Staff that the company's risk premium model is inflated, and that the Staff's traditional model is more appropriate and reliable. *See*, 6 Tr 5025.

In that regard, the Staff presented an average adjusted DCF estimate of 9.71% (6 Tr 5017), an average CAPM ROE estimate of 10.23% (6 Tr 5021), and the risk premium model historical ROE estimates of 10.05% for Utility bonds and 8.63% for the treasury-based method (6 Tr 5025). Overall, the Staff "recommends a return on equity of 9.90%, which is above the midpoint of Staff's 9.30% - 10.30% reasonable ROE range." 6 Tr 5013. Giving appropriate weight to the Staff's analyses, as well as the parties' ranges of ROE on the record, the Commission finds that the Staff's proposed ROE of 9.90% is well-supported. As such, the Commission finds that maintaining the company's ROE of 9.90% is reasonable and prudent, and therefore is adopted.

D. Overall Rate of Return

The Commission adopts a 50/50 debt to equity capital structure, a long-term debt cost rate of 4.24%, a short-term debt cost rate of 5.73%, an ROE of 9.90%, and an overall weighted cost of capital of 5.69%, as shown on the table below:

Description	Amount ($000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	8,663,922	39.19%	4.24%	1.66%
Common Shareholders' Equity	8,673,528	39.23%	9.90%	3.88%
Short-Term Debt	509,454	2.30%	5.73%	0.13%
Investment Tax Credit – Debt	15,734	0.07%	4.24%	0.00%
Investment Tax Credit – Equity	15,751	0.07%	9.90%	0.01%
Deferred Income Taxes (Net)	4,229,600	19.13%	0.00%	0.00%
Total	**22,107,989**	**100.00%**		**5.69%**

VII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY

To determine DTE Electric's net operating income (NOI), the company's operating expenses are subtracted from its operating revenue. DTE Electric initially projected its NOI for the projected test year at $1,087.1 million. After adopting certain adjustments and updates proposed by the Staff and other intervening parties, as detailed below, DTE Electric agrees to increase its projected NOI to $1,092 million for the projected test year. 6 Tr 1508, 1510; *see also*, Exhibit A-13, Schedule C1, and DTE Electric's initial brief, p. 208, Attachment A, p. 3.

After certain adjustments in the Staff's initial NOI projection and including its adjustments to certain of DTE Electric's projected revenues and expenses, the Staff's final NOI projection is $1,175.32 million which is an increase over its initial filing of $1,174.57 million. 6 Tr 4936; *see also*, Exhibit S-3, Schedule C-1.1, and Staff's initial brief, Appendices C, L. 49, and F, lines 1438. The Staff's adjustments and recommendations are discussed individually, below.

A. Sales Forecast

The company states that it used forecasting methodology similar to what was used in Case No. U-21297 to develop an individual forecast for each major customer class: residential, small C&I, large C&I, and other. DTE Electric testifies that a variety of factors affect sales and customer forecasts, for example:

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

6 Tr 1775-1776; *see also*, 6 Tr 1776-1788, and Exhibits A-15, Schedule E1, pp. 1-3, and Schedule E-2, pp. 1-2. DTE Electric notes that its sales have decreased over the past five years

and projects that the downward trend will continue. 6 Tr 1788; *see also*, Exhibit A-15, Schedule E2, pp. 1-2.

The company testifies that "[t]he service area system output and annual peak demand for the projected test year, January 2025 through December 2025 are 47,341 GWh [gigawatt-hours] and 10,911 MW [megawatts], respectively. The projected test year bundled system output and annual peak demand are 42,683 GWh and 10,157 MW, respectively." 6 Tr 1795. The company also testifies that "[t]he service area sales for the projected test [year] . . . are 44,189 GWh and bundled sales are 39,756 GWh." 6 Tr 1789; *see also*, Exhibits A-15, Schedule E1, pp. 1-3, and Exhibit A-15, Schedule E2, pp. 1-2.

No party objects to DTE Electric's forecasted sales figures and the Staff recommends that the Commission adopt the figures. Staff's initial brief, p. 75

The Commission finds that the company's forecasted sales figures are supported in the record and are reasonable. Accordingly, the Commission adopts the sales figures as stated above.

B. Fuel and Purchased Power Revenue and Expense

DTE Electric proposes to continue its base generation PSCR of 31.26 mills per kWh but seeks to update the company's loss factor to 7.69% resulting in an increase in its base sales PSCR level to 33.66 mills per kWh. The company testifies that, in its projections, it uses a 33.66 mills per kWh base, a zero PSCR factor, and no over- or underrecovery, and that total expense, including transmission expense, for the test year is $1,354 million. 6 Tr 2583-2584; *see also*, Exhibit A-13, Schedule C-4.

The Staff recommends that the Commission adopt the company's fuel and purchased power revenue projection. Staff's initial brief, p. 87, *see also*, *id*., Appendix C.

No party, other than the Staff, expresses an opinion on DTE Electric's fuel and purchased power revenue projection.

The Commission finds the company's projection is supported in the record and is reasonable. Accordingly, the Commission adopts the company's projection as stated above.

C. Operations and Maintenance Expenses

DTE Electric testifies that the company projects its normalized O&M expense will increase by $42.5 million for the projected test year. 6 Tr 1493. The company testifies that it "started with actual year ended December 31, 2022 results normalized for unusual, non-recurring items and eliminations/reclassifications for ratemaking purposes. The normalized O&M amounts were then escalated for the effects of inflation and adjusted to reflect anticipated material changes." 4 Tr 1496; *see also*, Exhibit A-13, Schedule C1, line 4.

1. Inflation

DTE Electric testifies that it projects a composite inflation rate of 2.90% for 2024 and 2025 that includes a 3% inflation rate for both internal labor and contract labor inflation expenses. 6 Tr 1497; *see also*, Exhibit A-13, Schedule C5.15. Non-labor inflation costs are projected at 2.4% for 2024 and 2.2% for 2025. *See*, Exhibit A-13, Schedule C5.15. The company further testifies that it used the CPI-U that is published by S&P/IHS Markit to determine interest for non-labor costs only. For both contract and non-contract labor costs, the company states that it based its inflation projection solely on labor costs because such costs are not tied to the CPI and that "it is more appropriate to use a specific and known wage factor rather than an overall measure of inflation." 6 Tr 1497; *see also*, Exhibit A-13, Schedule C5.15.

The Attorney General opposes the company's calculation of its inflation rate. First, the Attorney General asserts that the company should have developed its inflation figures from the

2023 O&M expenses rather than the 2022 expenses because the company significantly reduced its O&M expenses in 2023. 6 Tr 3685. Second, the Attorney General notes that the Commission has rejected the blended rate in past rate cases, preferring the use of the CPI-U inflation rates to forecast inflation. 6 Tr 3685. The Attorney General avers that the company's inflation projection should be based on the combined CPI-U rates of 2.4% for 2024 and 2.2% for 2025 which results in a $14.6 million reduction in the company's projected inflation costs. 6 Tr 3685-3686. In her reply brief, the Attorney General repeats the arguments made in testimony. Attorney General's reply brief, p. 34.

MNSC observes that DTE Electric projects O&M expenses will increase by $42.5 million above the company's 2022 historical level and that the foremost reason for the increase is the company's blended rate of inflation. MNSC notes that the company's projected non-labor inflation rate is 2.4% for 2024 and 2.2% for 2025, while the labor-related inflation rate is 3%. 6 Tr 3741. MNSC also states that the company did not consider how productivity gains would affect inflation which, in this case, should be approximately 0.70% for labor-related inflation and 0.61% for non-labor-related inflation. Thus, MNSC posits, the company's labor-related inflation rate should be reduced by 0.70%, and its non-labor inflation rate should be reduced by 0.61%, particularly considering DTE Electric's lack of competition as a regulated utility. 6 Tr 3742. In briefing, MNSC argues that the Commission should adopt its inflation reductions, or, in the alternative, adopt either ABATE's or the Attorney General's inflation reductions. MNSC's initial brief, p. 113. MNSC does not address this issue in its reply brief.

ABATE opposes the company applying inflation to 2023 projections when 2023 actual figures are available, and recommends eliminating DTE Electric's proposed inflation adjustment for 2023. 6 Tr 3336. As well, ABATE asserts that inflation is lower than the company projects based on

"Blue Chip Economic Indicators industry expert consensus Real GDP Chained Price Index [which] shows 2.3% for 2024, and 1.8% for 2025." 6 Tr 3341. ABATE also posits that the cost of labor may be less than projected due to retiring employees being replaced by new employees that are paid a lesser wage or new employees being hired at a lesser wage than existing employees. 6 Tr 3341. ABATE recommends that inflation rates be based on the Real GDP Chained Price Index which, it believes, more accurately reflects consumer purchases than does the CPI. ABATE acknowledges the issue of the impact that increased productivity may have on the inflation rate but does not address it in testimony. 6 Tr 3342.

In its reply brief, DTE Electric points out that the Commission has approved a blended inflation rate in the past. The company also opines that rates based on the Real GDP Chained Price Index were not proven to be more accurate than rates based on the CPI-U and that adding a productivity component to the calculation would result in a second counting of improved productivity that is already built into the company's calculations. DTE Electric's reply brief, pp. 73-75.

In its reply brief, ABATE denies DTE Electric's assertion that ABATE did not prove that the Real GDP Chained Price Index is a better predictor of non-labor costs than the CPI-U. Further, ABATE asserts that the company's method of calculation is flawed. ABATE's reply brief, pp. 16-17.

The Commission finds that the blended inflation rate that DTE Electric proposes is supported in the record and is reasonable. Thus, the Commission adopts the company's 3% inflation rate for both internal labor and contract labor inflation expenses, non-labor inflation costs of 2.4% for 2024 and 2.2% for 2025, and an overall 2.90% inflation rate for 2024 and 2025. *See*,

Exhibit A-13, Schedule C5.15. Accordingly, and as discussed above in Part V, Section B.4 of this order, the Commission declines to adopt the alternative inflation calculations proposed by the Attorney General, ABATE, and MNSC.

2. Energy Supply Operations and Maintenance

DTE Electric explains that energy supply operations expenses are related to day-to-day generating unit operations and that energy supply maintenance is related to outages (both periodic and nonperiodic), and day-to-day maintenance of plant equipment that does not require taking the unit offline. 6 Tr 1708. The company testifies that it developed its energy supply O&M forecast, which considers the three major cost categories of steam power generation, hydraulic generation, and generation by other means, by adjusting historical test year O&M data for cost changes in materials, environmental equipment operation, and non-periodic cost variations, among other things. 6 Tr 1706-1707.

In its reply brief, the company argues that its projection for energy supply O&M expenses are reasonable and prudent and that appropriate inflation rates are fully supported by testimony and exhibits. The company recommends that arguments to the contrary should be rejected. *See*, DTE Electric's reply brief, p. 75. *See*, discussion of individual energy supply matters, below.

a. Steam Power Generation

DTE Electric projects its steam power generation adjusted O&M expense to be $213.4 million in the projected test year. The company points out that $8.3 million in steam power generation O&M expenses attributed to fuel supply and MERC fuel handling are deducted from the steam power generation O&M expenses. 6 Tr 1708; *see also*, Exhibit A-13, Schedules C5 and C5.1.

The company also states that to reach its total adjusted O&M steam power generation amount, inflation adjustments for labor and materials were made at the rate of 2.90% for 2024 and 2025 and other adjustments were made to remove expenses from 2022 totals that would not recur in the projected test year. 6 Tr 1713-1714; *see also*, Exhibit A-13, Schedule C5.1. The company did not address steam power generation O&M in its reply brief.

The Attorney General argues that 2023 steam power generation figures are $30 million less than the 2022 figures used by DTE Electric and would result in a forecast that is $21.5 million less that the company's forecast. 6 Tr 3686-3687. The Attorney General recommends that the company's O&M forecast be reduced by $21.5 million. 6 Tr 3687. The Attorney General did not address this topic in her reply brief.

The Staff recommends that DTE Electric's steam power generation O&M projection be reduced by $19.40 million based on the use of 2023 historical figures rather than 2022 historical figures. The Staff reasons that the company's O&M expenses were greatly reduced in 2023 due to the closures in 2022 of the St. Clair and Trenton Channel plants and the addition of the BWEC, and that actual O&M figures for 2023 are available without need for adjustment. 6 Tr 5185-5186; *see also*, Exhibit S-16.7. The Staff did not address this issue in its reply brief.

There were no other objections to the company's steam power generation projection with the exception of the opposition to DTE Electric's use of a blended 2.90% rate of inflation, which the Commission approves, as discussed above.

The Commission finds it is appropriate to update DTE Electric's projection, which is based on 2022 historical costs, to a projection based on 2023 historical costs, as recommended by the Staff, for a reduction to the company's O&M steam power generation projection of $19.40 million. As the Staff states, 2023 steam power generation O&M costs were significantly reduced due to the change in DTE Electric's generation fleet, and those changes materially change the necessary

O&M for steam power generation. Accordingly, the Commission adopts the Staff's recommended adjustment of $19.40 million.

b. Hydraulic Power Generation

DTE Electric testifies that it projects $11.2 million in adjusted hydraulic power generation O&M for the projected test year. DTE Electric states that this figure represents the company's share of the O&M expenses at Ludington and is based on 2022 historical figures adjusted for the projected test year with a 2.90% blended rate for inflation. 6 Tr 1714; *see also*, Exhibit A-13, Schedules C5 and C5.4.

No parties object to DTE Electric's adjusted hydraulic power generation O&M projection with the exception of opposition to the company's blended rate of inflation, which the Commission approves, as discussed above.

The Commission finds that DTE Electric's projected O&M for hydraulic power generation is supported in the record and is reasonable. As such, the Commission adopts the company's projections.

3. Midwest Energy Resources Company Fuel Handling and Fuel Supply

DTE Electric testifies that fuel supply O&M expenditures are essentially used for "planning, procurement, and contract administration of the fossil fuel commodities including transportation to plants and the costs to maintain the Company's railcar fleet" and that MERC[35] O&M expenditures are used for "the operation of the coal terminal that processes rail shipments of western coal for lake vessel delivery to DTE Electric's power generation plants in southern Michigan." 6 Tr 1763.

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[35] DTE Electric testifies that MERC is a coal terminal that provides both transportation and transshipment of coal, is a wholly owned subsidiary of DTE Electric, and is fully consolidated into the company. 6 Tr 1753-1754.

The company projects that, based on 2022 historical totals and after adjustments are made for inflation and reclassification of fuel handling to O&M, DTE Electric's fuel supply costs are projected at $4.9 million for the projected test year. The company projects MERC fuel handling costs will be $8.1 million after inflation adjustments were made at a blended rate of 2.90% each for 2024 and 2025. 6 Tr 1765; s*ee also*, Exhibit A-13, Schedules C5 and C5.2.

The Staff recommends that DTE Electric's projections for MERC fuel handling and fuel supply should be reduced by a total of $463,000 based on the use of 2023 historical figures rather than 2022 historical figures when calculating its projection because no adjustment for inflation would have been needed for 2023 as actual figures were available. 6 Tr 5186; *see also*, Exhibit S-16.7, p. 2.

In its reply brief, the company argues that it fully supported its MERC fuel handling and fuel supply in its case presentation referring to testimony explaining how the O&M projections were developed. DTE Electric's reply brief, p. 75; s*ee also*, 6 Tr 1496-1497.

The Staff did not address this issue in its reply brief but states that "[t]he Commission should not consider Staff's silence on any argument raised by another party as an agreement with that party's position." Staff's reply brief, p. 4.

No other party objects to DTE Electric's projection for MERC fuel handling and fuel supply except for objections to the company's use of a blended inflation rate, which the Commission approves, as discussed above.

The Commission finds it is appropriate to update DTE Electric's projection, which was based on historical year 2022, to a projection based on historical year 2023, as recommended by the Staff. *See*, 6 Tr 5186. Therefore, the Commission adopts the Staff's recommended adjustment of $463,000 for MERC fuel handling and for fuel supply.

4. Nuclear Power

DTE Electric calculates its total adjusted nuclear power generation O&M expenses to be $159.4 million for the projected test year. The company states that it used 2022 as the historical test year and applied adjustments for the nuclear surcharge and program evaluation review committee (PERC) nuclear project expenditures, with no other historical adjustments, resulting in a test year adjusted total of $191.8 million. For the projected test year, the company testifies that it made adjustments for inflation, outage accrual, and PERC expense, resulting in the $32.4 million increase over the adjusted 2022 total. 6 Tr 1855-1856, 1866-1877; *see also*, Exhibit A-13, Schedules C5 and C5.3, p. 1.

The Staff recommends that the company's nuclear power generation O&M projection be reduced by $371,000 based on use of 2023 historical figures rather than 2022 historical figures to calculate its projection. The Staff asserts that no adjustment for inflation would be needed if 2023 actuals are used because the actual figures for that timeframe are available. 6 Tr 5185-5186; *see also*, Exhibit S-16.7, p. 3.

In its reply brief, DTE Electric reiterated that it fully supported its O&M projections in its case presentation. DTE Electric's reply brief, p. 75; *see also*, 6 Tr 1466, 1496-1497.

No other parties object to the company's nuclear power generation projection with the exception of the company's use of a blended 2.90% rate of inflation, which the Commission approves, as discussed above.

The Commission finds it is appropriate to update DTE Electric's projection, which was based on historical year 2022, to a projection based on historical year 2023, as recommended by the Staff. *See*, 6 Tr 5185-5186. Therefore, the Commission adopts the Staff's adjustment of $371,000 for nuclear power O&M.

5. Other Power Generation

DTE Electric projects its adjusted O&M expense for other power generation to be $31.5 million for the projected test year. The company testifies that it used the 2022 adjusted historical test year total as the basis for its projection adjusted to remove $37.7 million from the 2022 amounts for unrelated renewable energy program expenses, to increase expenses by $6.3 million for the BWEC, and to increase expenses by $0.31 million for Slocum BESS operations. 6 Tr 1715-1716; *see also*, Exhibit A-13, Schedules C5 and C5.5.

The Staff recommends that DTE Electric's projection for other power generation O&M be reduced by $3.01 million based on the use of 2023 historical figures rather than 2022 historical figures for its calculation. The Staff asserts that, with the use of 2023 historical figures, the 2023 amounts include interest so no interest adjustment would be needed for 2023, and that BWEC was in operation for the full year with its O&M totals available to include in projected test year calculations. 6 Tr 5185-5186; *see also*, Exhibit S-16.7, p. 4.

No other parties object to the company's calculation other than its use of the 2.90% blended inflation rate, which the Commission approves, as discussed above.

As with a number of issues discussed above, the Commission finds it is appropriate to update DTE Electric's projection, which was based on historical year 2022, to a projection based on historical year 2023, as recommended by the Staff, which would also allow the company to use a full year of operations for BWEC. *See*, 6 Tr 5185-5186. Accordingly, the Commission adopts the Staff's $3.01 million adjustment.

6. Distribution

DTE Electric projects $359.2 million in distribution O&M expenses for the projected test year. The company states that distribution O&M expenses include costs related to both distribution and maintenance, including underground and overhead lines, meter expenses, and street lighting, among others. The forecast for each item was calculated using one of two methods to arrive at the 2025 projected test year amount: (1) the adjusted and normalized O&M expenses from historical year 2022 adjusted for anticipated expenses and inflation or (2) the five-year average (2018 through 2022) adjusted for inflation and other anticipated costs. 3 Tr 317-322; *see also*, Exhibit A-13, Schedule C5.6.

a. Storm Restoration

Included in the total distribution O&M projection were storm restoration O&M expenses projected at $64.5 million, calculated on a five-year trailing average that began with the 2022 historical test year and included the preceding four years with adjustment for inflation. The company then applied an inflation adjustment to the five-year adjusted average of $56.03 million to arrive at the total for the projected test year of $64.5 million. *See*, Exhibit A-13, Schedule C5.6. The company argues that, because there exists the possibility of over or under recovery associated with storm restoration expenses, there should be a SRCSM. The SRCSM is discussed in Part VIII, Section B. 2 Tr 128-129; 3 Tr 321.

Setting aside the company's arguments in favor of an SRCSM, the company states that storm restoration expenses vary greatly from year-to-year depending on the frequency and duration of extreme weather events. For example, the company testifies, a 17% decrease in storm restoration expenses occurred between 2021 and 2022, and an 85% increase between 2020 and 2021. The company argues that trends toward more extreme weather in Michigan are expected to continue. 2 Tr 130-132; *see also*, 2 Tr 130, Figure 10, and 2 Tr 131, Figure 11.

No party expresses opposition to the company's storm restoration projection with the exception of the 2.90% blended rate of inflation, which the Commission accepts, as discussed above.

The Commission finds DTE Electric's storm restoration projection for the projected test year is supported in the record and is reasonable. Therefore, the Commission approves the projection.

b. Tree Trimming

DTE Electric acknowledges that tree-related problems cause approximately two-thirds of all power outages, and the company has developed tree trimming and vegetation management programs to address this problem. For example, the company describes its ETTP which was initiated in 2016 and is a "program to address tree interference by trimming to an enhanced specification . . . designed to reclaim right of ways, remove or reduce vegetation hazards from distribution infrastructure, and properly define trim specifications for vegetation encroachment." 6 Tr 2964.

The company describes its tree trim surge program (Surge), which was initiated in 2018. The company states that the purpose of the Surge is:

> to secure the necessary funding to trim all circuit miles to the ETTP specification by the end of 2025. The Company proposed maintaining a 5-year cycle (3-year cycle for Subtransmission) for all miles, including those trimmed in the early years of the Surge. This means a circuit trimmed to the ETTP specification in 2016 or later would be maintained on a 5-year cycle length while the Company addressed additional off-cycle miles in the later years of the Surge.

6 Tr 2964-2965. The company testifies that it expects the Surge to last seven years, beginning in 2019 and continuing through 2025, and projects that the program will be 100% on-cycle[36] by the end of 2025. 6 Tr 2965-2966; *see also*, Exhibit A-31, Schedule V1.

The company testifies that either the company or an independent third-party contractor inspects all circuits post-trimming and that any shortcoming is corrected at no cost by the tree contractor that performed the work. The company further testifies that it has developed a methodology to evaluate the effectiveness of circuits trimmed to the ETTP specification and states that its ETTP method is successful, resulting in fewer outages and reduced outage times where circuits have been trimmed to the ETTP standard. 6 Tr 2967-2972; *see also*, Exhibits A-31, Schedule V1, pp. 7-10, Tables 10-16 and 6 Tr 2970, Table 2; 6 Tr 2971, Table 3; 6 Tr 2972, Table 4. The company notes that the majority of circuits are now trimmed to ETTP standards such that the remaining non-ETTP circuits are a less effective measure of ETTP effectiveness. 6 Tr 2972.

DTE Electric acknowledges that the Surge has required greater spending than when initially conceived and that the company recently identified an area where additional funding is needed in order to complete the Surge in 2025 and maintain on-cycle tree trims. DTE Electric states that, using historical costs, the company prepared its cost-per-mile, seven-year model projecting that, for every $1 million spent to reclaim circuits to ETTP standards, there would be a 40% savings in the next on-cycle trim. However, while initial reclaim tree trim costs are less than projected, the actual cost of on-cycle trim work, averaged for historical years 2021 through 2023, is higher than

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[36] The company testifies that being "[o]n-cycle means that the circuit miles have been trimmed to the ETTP specification at least once and are on a maintenance trimming cycle for future years." 6 Tr 2966.

projected. The company also reports that 48% of circuits to be cleared are in backlots or are inaccessible by equipment and that differences "in work location and removal rates means that complexity and volume of work for on-cycle trimming is higher than originally assumed, resulting in lower savings." 6 Tr 2978; 6 Tr 2978, Table 5; *see also*, 6 Tr 2975-2979. DTE Electric also cites increased union labor costs and inflation, as well as the addition of spot trimming and the resumption of the Detroit Tree Trim Academy in 2022, following the COVID-19 pandemic, as reasons for increased Surge costs. 6 Tr 2980-2981.

In addition to the currently approved 2025 Surge amount of $44 million categorized as a regulatory asset, the company requests an additional $87 million to be categorized as an incremental regulatory asset. The company states that its total approved Surge funding for 2019 through 2025 is $409.50 million and that after the $87 million additional Surge funding projected for 2025 is added, the total Surge funding will be $496.50 million. 2 Tr 93-94.

The company clarifies that the Commission initially approved three years of incremental regulatory asset treatment for the Surge program expenses with other tree trimming O&M expenses booked as base tree trimming O&M and states that the Commission has continued to approve the Surge funding and regulatory asset treatment. 2 Tr 94-95; 6 Tr 2965.

DTE Electric testifies that it should be permitted to recover its actual cost of financing for the Surge, i.e., apply a long-term interest rate. The company states that it plans "to wait until the projected 2025 surge completion before making its next securitization filing. The larger deferred balance will more efficiently spread the fixed costs and reduce overall securitization costs to customers." 2 Tr 96. The company states that its securitization filing following the end of the Surge will include "all expenditures not previously securitized," noting that "$156.9 million of [the total incremental costs through 2024 of $365.8 million] were securitized in March 2022 pursuant to the Commission's June 23, 2021 order in Case No. U-21015." 6 Tr 2984; *see also*, 2 Tr 96.

Non-Surge tree trimming O&M expenses typically include line clearance maintenance; non-storm reactive tree trims listed as "trouble;" miscellaneous related tree-trim expenses such as auditing, training, the herbicide program, software maintenance, and safety; and the staff costs related to tree trimming. The company spent a total of $239.57 million in 2022 and $169.67 million in 2023 on tree trimming and related O&M expenses. *See*, Exhibit A-31, Schedule V1, pp. 4-5. DTE Electric requests base tree trimming, non-Surge O&M expenses in the amount of $109 million for the projected test year, which is a $3.37 million increase over historical year 2022. 6 Tr 2982-2984; *see also*, 6 Tr 2983, Table 7, and Exhibit A-13, Schedule C5.6.1.

The Staff supports the company's proposed $109 million in base O&M tree trimming funds, as well as the company's request for $87 million in additional Surge funds for the 2025 test year, which is the final year of the Surge. 6 Tr 2982-2983, 5145. Additionally, the Staff tentatively supports the company's continued move toward a risk-based tree trim cycle following Surge completion, but thinks it would be prudent to wait until the audit results are finalized before making a final decision on the matter. 6 Tr 2989, 5146; *see also*, December 1 order, p. 353. Regarding DTE Electric's proposal to perform more aggressive tree trimming in zones two and three, the Staff is in favor of the company comparing circuits receiving regular maintenance trimming with circuits trimmed during construction to determine whether zones two and three need more aggressive tree trimming. 6 Tr 2983, 2996, 5147.

The Staff also testifies that DTE Electric calculated its ROR for the Surge at 9.2%, which is the company's ROR for permanent capital investments. The Staff states that this ROR is not appropriate because the Commission approved the short-term debt rate in the December 1 order, finding "that the '[Surge] program should remain as it is.'" 6 Tr 4990 (quoting the December 1 order, p. 280). Consistent with the December 1 order, the Staff calculated the Surge ROR at 4.96%, creating a return on the Surge regulatory asset of $10,133,000. 6 Tr 4990-4991; *see also*, Exhibit S-4, Schedule D3.

The Attorney General opposes the $87 million in additional Surge funding because, if approved, the Surge will cost $251.2 million more than forecasted in 2018 and, when considering all tree trimming expenses, including capitalized expenses, the company has spent about $1.9 billion on tree trimming and vegetation management but the company has not provided clear evidence that the expenses have significantly improved the overall number of outages. Further, the Attorney General protests the extreme increase in contractor fees and labor, the poor success rate of the Detroit Tree Trim Academy in providing additional qualified labor, and the unexplained removal of less than half the number of trees than were projected. 6 Tr 3649-3654; *see also*, 6 Tr 3651, chart.

The Attorney General urges the Commission to reject the company's request for $87 million in additional Surge funding and to remove $8.89 million from the revenue requirement (deferred balance calculated without the $87 million at the short-term interest rate of 5.76% equals an ROR of $9.90 million which is $8.89 million lower than the amount forecasted by the company). 6 Tr 3655. The Attorney General also recommends that the Commission remove capital expenditures of $3.08 million for 2022 and $3.82 million for 2023 because DTE Electric "did not perform a cost/benefit analysis and did not justify that the model and related expenditures are economically beneficial to customers." 6 Tr 3656.

AGMN recommends that DTE Electric be ordered to continue its annual public tree trimming report and that the Commission institute a five-year audit of the state of the company's overhead

ROW as a means to determine whether the line had ever been trimmed to ETTP standards and to prevent backsliding on the frequency and quality of the company's tree trimming and vegetation management post-Surge. 6 Tr 3956-3958.

Ann Arbor testifies that it has its own tree trimming program in addition to DTE Electric's program and that the City will complete its 10-year cycle in 2026, then move on to a 7-year cycle. 6 Tr 4215. The City testifies that its data shows that trees not trimmed to its quality and frequency standards are more than twice as likely to need reactive maintenance in the coming year and opines that if DTE Electric falls behind on its trimming schedule it will negatively affect its residents through more outages, dangerous loose power lines during storms, and increased outage restoration costs. The City also asserts that underground methane causes trees to die from the top down and thus, there exists a risk that untrimmed dead branches may fall on power lines and cause outages. 6 Tr 4217-4219.

The Commission finds that DTE Electric's projection for tree trimming O&M of $109 million and Surge funding of $87 million are supported in the record and are reasonable. Accordingly, the Commission adopts the company's projections. Additionally, the Commission finds that the company's progress towards completion of the Surge, however more challenging than first anticipated, is supported in the record and is reasonable. The Commission declines to order a five-year audit or additional tree trim reports, finding that, at this time, the company's annual tree trimming report provides sufficient information to keep the Commission abreast of the company's tree trimming activities. Further tree trim reporting following the end of the Surge may be revisited in future rate cases. The Commission further recognizes that the results of the audit performed in Case No. U-21305 may affect this expense category.

The Commission is not persuaded that the company's ROR on its Surge regulatory asset should be at the cost of permanent capital, and finds that, as it did in Case No. U-21297, the ROR should remain at the short-term debt interest rate, which, in this case is 5.73%. *See*, 6 Tr 4990-4991, 5012-5013; *see also*, Staff's initial brief, p. 109, and December 1 order, p. 280.

The Commission expects 2025 to be the final year for the Surge and that, upon the end of the Surge, tree trimming costs will revert to O&M and the funds that are classified as a regulatory asset will be securitized.

The capitalization of tree trim activities is discussed in Part VIII, Section F.1, below.

7. Community Lighting

DTE Electric projects community lighting O&M expenses at $4.1 million, which is calculated using the 2022 historical year total normalized to include a reduction in expected outage expenditures of $0.25 million and adjusted for inflation. The company testifies that its street lighting O&M projection includes costs for preventive maintenance such as streetlighting post painting, inspections, and night patrols, non-capitalized outage restoration, and labor costs that include costs for planning, construction and asset engineering, and asset maintenance, among other things. 6 Tr 3117-3118, Exhibit A-13, Schedule C5.6.

MI-MAUI contends that DTE Electric has collected "more than half a million dollars for [streetlight inspection and post painting] that was not spent" even though MI-MAUI members report the concerning condition of decorative light posts that are not being properly maintained despite MI-Maui's members having paid extra for the service. 6 Tr 4313, 4315; *see also*, 6 Tr 4314, chart. MI-MAUI further contends that, in this rate case, the company proposes to spend less than was approved in previous rate cases. 6 Tr 4313-4315.

MI-MAUI argues that because the company underspent for streetlight pole inspection and painting in 2022 and 2023, and has most likely underspent in 2024, it has already recovered its 2025 projected test year amount and, therefore, the Commission should disallow recovery of streetlight inspection and post painting costs for the projected test year but require the company to perform inspections and post painting at the historical pace. 6 Tr 4314-4315. MI-MAUI also recommends that the Commission insist the company conduct "robust inspection and maintenance programs" so that premature capital replacement costs are not incurred and to require in the company's next rate case "a report on actual costs with amounts recovered in rates, looking back five years." 6 Tr 4315-4316.

MI-MAUI also contends that the company should increase the scope of its night patrol program because many outages have been identified through this program prior to being reported by community members, thus providing for fast restoration of service and insight into the reasons for outages. However, MI-MAUI accepts the company's night patrol projection for the projected test year with no recommendation to increase projected costs. 6 Tr 4316, 4326-4327; *see also*, 6 Tr 4326, chart.

In rebuttal, DTE Electric agrees with MI-MAUI that its streetlight pole inspection and painting O&M projections have decreased due to transferring streetlight-only poles to its pole-top maintenance program and through the use of only one contractor rather than two contractors as in the past. However, DTE Electric asserts that while it may have underspent its 2022 and 2023 streetlight inspection and painting budget, the company overspent in these years on outage maintenance by $316,628 and $569,901 respectively. Thus, DTE Electric argues, a full disallowance of light post inspection and painting would be inappropriate. 6 Tr 3146, 3160-3161.

Further, the company expresses its opposition to MI-MAUI's suggestion that the company be required to file a report that details its actual costs compared with amounts recovered in rates for the previous five years. The company avers that, because projections are based on information available at the time, both favorable and unfavorable variables will always exist when actual costs are incurred. The company argues that, when narrow comparisons are made, such as those made by MI-MAUI when evaluating the company's inspection and post painting expenditures, the comparisons will not result in valid conclusions. 6 Tr 3161-3162.

Related to the company's streetlight underground cable system, DTE Electric categorizes certain expenses for locating and repairing underground cables as O&M. 6 Tr 3164. MI-MAUI proposes that the streetlight underground cable system be included in the company's DGP. 6 Tr 4316-4319. However, DTE Electric rebuts that this would be inappropriate because the streetlight cable system is completely separate from the company's distribution operations and thus "maintains its own rate base, a separate set of projected capital and O&M expenditures, etc." 6 Tr 3164-3165.

No other parties express an opinion on these issues with the exception of opposition to the company's use of a 2.90% blended inflation rate, which the Commission approves, as discussed above.

The Commission finds that DTE Electric's projection for streetlight post inspection and maintenance, night patrols, and other related community lighting O&M expenses are supported in the record and are reasonable. The Commission declines to order a five-year report of expenditures versus allowances included in rates at this time because such a report would be duplicative of processes that make up a significant part of the rate case process.

Additionally, the Commission notes that the company acknowledges it has significantly underspent on streetlight post inspection and maintenance in past years and implies that the underspend is due to overspending on outage restoration. Nonetheless, the record evidence suggests that streetlight customers may not be receiving appropriate maintenance services. The company cannot expect to continue to be approved funds to inspect and maintain streetlight posts if it does not adequately perform those tasks.

8. Customer Service, Merchant Fees

DTE Electric reports that its customer service programs provide service to DTE Electric and DTE Gas Company and that the DTE Electric portion of customer service O&M will increase in the projected test year to $118.63 million which excludes marketing costs of $8.35 million and includes customer accounts expenses of $100.31 million and customer service and informational expenses of $26.67 million. 6 Tr 2284-2300; *see also*, Exhibit A-13, Schedule C5.7.

Merchant fees,[37] which are part of the company's customer accounts expenses O&M, are projected to increase by $0.5 million as a result of increased use of debit and credit card payments, increased merchant fees, and the application of a 2.90% rate of inflation, according to DTE Electric. *See*, Exhibit A-13, Schedule C5.7.

The Staff recommends reducing DTE Electric's projected merchant fees O&M of $12.3 million to $11.06 million, as a result of the Staff using 2023 base historical figures rather than 2022 historical figures as used by the company. 6 Tr 1982, 4928; *see also*, Exhibit S-7.5.

In briefing, DTE Electric agreed with the Staff's updating the company's projection using

[37] Merchant fees are fees levied by a customer's credit and debit card issuer and payment processor. For customer power bill payments, DTE Electric assumes the cost of these fees. Industrial customers are not permitted to pay their bills with credit or debit cards and C&I customers are not permitted to use debit or credit cards for power bills that exceeded $75,000 in the previous calendar year. 6 Tr 1980-1981.

2023 figures and did not dispute the Staff's projected merchant fees for the projected test year of $11.06 million. S*ee*, Staff's initial brief, p. 94; and DTE Electric's reply brief, pp. 84.

The Attorney General opposes DTE Electric's merchant fee recovery for non-residential customers and proposes that $3.5 million in merchant fees O&M relating to non-residential debit and credit card use for paying power bills be disallowed. 6 Tr 3689-3691; *see also*, Exhibit A-13, Schedule C6.7. The Attorney General reasons that the small-to-medium sized businesses that make up the larger portion of non-residential merchant fee payers have other options they may employ to pay their power bills, such as electronic funds transfer or automatic clearing house. The Attorney General points out that residential merchant fees are typically about 10 or 11 cents per transaction while non-residential merchant fees are about $4.72 per transaction. The Attorney General avers that this disparity between residential and non-residential fee recovery is not reasonable and that the company should take remedial action. Accordingly, the Attorney General recommends that $3.5 million in non-residential merchant fees for the projected test year be disallowed so that the company may take action to avoid the non-residential merchant fee costs. 6 Tr 3690-3691.

In her reply brief, the Attorney General argues that the company did not adequately explain why customers should assume the merchant fee costs for non-residential customers when other, cheaper methods of payment are available, and points out that Consumers Energy Company imposes a convenience fee for customers who use a credit card for payment. Attorney General's reply brief, pp. 66-67.

DTE Electric testifies that the company began to limit merchant fees in 2019 when it proposed to exclude industrial customers in Case No. U-20162, and in 2021 when it limited C&I customers' use of credit and debit card to those "whose aggregate annual energy bill in the preceding calendar year was less than $75,000." 6 Tr 1981; *see also*, 6 Tr 1982, Table 16. The company avers that through these measures O&M non-residential merchant fee recovery costs have been reduced by 22% from 2019 to 2022 and rebuts that "according to the National Small Business Association, approximately 37% of small businesses have used credit cards over the past 12 months to meet their capital needs which suggests that facilitating credit card use for small business is a meaningful part of maintaining business customer satisfaction and financial flexibility." 6 Tr 1982, 2017. In briefing, the company reiterates its testimony on the matter and its disagreement with the Attorney General. DTE Electric's reply brief, p. 37.

DTE Electric agrees with the Staff's recommendation that 2023 historical figures should be used to project the company's merchant fees O&M for a total test year projection of $11.06 million. S*ee*, Staff's initial brief, p. 94; and DTE Electric's reply brief, p. 84. Accordingly, the Commission adopts the Staff's projection.

As it recently did in the November 7 order, the Commission agrees with the Attorney General that the company has failed to adequately explain why customers should assume the merchant fee costs for non-residential customers when other, cheaper methods of payment are available. November 7 order, pp. 156-158. As such, the Commission adopts the Attorney General's $3.5 million disallowance for non-residential merchant fees for the projected test year to be applied to the agreed upon test year projection of $11.06 million. *See*, Staff's initial brief, p. 94; and DTE Electric's reply brief, p, 84.

In addition, as in the November 7 order, "the Commission notes that because the merchant fees associated with residential customers was not contested in this case, it is not addressed in this order. However, the Commission finds that the same reasoning would apply: it is not reasonable or prudent to socialize over the utility's customer base the merchant fees for customers who choose to pay by credit card." November 7 order, p. 158.

9. Uncollectible Accounts Expense

DTE Electric testifies that it records its uncollectible expense (UCX) in its accounts receivable reserve and determines its UCX via a multi-step calculation using a 12-month rolling average for residential and small commercial accounts and a 60-month rolling average for large C&I accounts. 6 Tr 2375-2376, *see also*, 6 Tr 2375, Figure 1. The company states that it generally writes off accounts as uncollectible when they are 150 days past the final due date of the bill, although occasionally such accounts may not be written off because there exists a repayment agreement or a pending dispute on the bill. In this rate case, DTE Electric states that, similarly to the Staff's methodology in Case No. U-21297, the company "used a three-year average of actual net write-offs plus direct expense for 2020-2022 and adjusted for revenue growth, resulting in a [sic] $50.9 million of uncollectible expense." 6 Tr 2376-2377; *see also*, Exhibit A-13, Schedule C5.8. The company reports that it has not sold any debt in the previous five years and does not plan any debt sales for the projected test year. 6 Tr 2377.

The Staff counters that:

> the Company's methodology is consistent with Staff's direct write off method, [but] the revenue amount used is excessive. Revenue is multiplied by the bad debt loss ratio (BDLR) to create the expense projection. See Exhibit A-13, Schedule C5.8. Staff requested the revenue categories that compose its projection. An excessive revenue amount creates an unreasonable UCX projection. The Company responded that its UCX calculation uses Total Proposed Revenue presented on Exhibit A-16, Schedule F2, column c. Also it included the addition of PSCR revenue not presented on Company exhibits. Staff disagrees with the use of the proposed revenue. Use of future revenue at proposed rates creates an iterative calculation for the Cost-of-Service study. Also, using projected revenue at the Company's proposed rates creates an excessive UCX projection. It is unlikely the Company's proposed rates will be approved without recommended adjustments. It is also Staff's position that PSCR revenue should be excluded as it is not present on the Company's exhibits and audited by Staff in this general rate case. Staff

> recommends the use of total current revenue projected by test year billing determinants at the current known rates, as presented on Exhibit A-16 Schedule F2, page 2, col. b., ln. 49. Projected revenue at the current known rates creates a more reasonable UCX projection which is not iterative regarding the Cost-of-Service study.

6 Tr 4991.

The Staff recommends that the company use 2023 in its three-year projection as that is the most recent information available using the direct write-off method. The Staff states that it "applied the BDLR from years 2021 through 2023 to total present revenue amount sourced from Company Exhibit A-16 F2, page 2, col. b., ln. 49." 6 Tr 4991. Employing this calculation, the Staff recommends reducing the company's uncollectible account O&M by $9,841 million for a total uncollectible expense projection of $41.03 million. 6 Tr 4991-4992; *see also*, Exhibits S-14.0 and S-14.1.

The Attorney General testifies that the Commission should reduce DTE Electric's uncollectible O&M projection to $47.0 million. The Attorney General states that her calculation is based on the same elements as DTE Electric's calculation with the exception of updating figures with the Commission-approved three-year average to include 2021, 2022, and 2023 to arrive at net charge offs for the period in the amount of $40.0 million, $37.7 million, and $44.1 million per year, respectively. The Attorney General states that, "when the average percentage of 0.716% as the ratio of net charge offs to revenue for the three-year historical period . . . is multiplied by the projected test year revenues of $6.399 billion" the result is a forecasted uncollectible account projection of $48.5 million. 6 Tr 3692. She concludes that, after "add[ing] average amounts charged directly to other accounts of $1.2 million," the uncollectible account projection is $47.0 million. 6 Tr 3693. In her reply brief, the Attorney General asserts that DTE Electric agrees with her uncollectible account calculation. Attorney General's reply brief, p. 67.

DTE Electric rebuts that use of present revenue based on current rates rather than projected revenue that considers new rates (if the request is fully approved) is unjust and that removing PSCR revenue "is not consistent with how the historical uncollectible expense as a percent (%) of revenue is calculated." 6 Tr 2382. DTE Electric avers that the Attorney General's projection is consistent with the Commission's past orders and that she correctly uses projected revenue that includes PSCR revenue and is updated to a three-year average that includes 2023, which the company does not object to, and results in an adjustment of $3.8 million, reducing the uncollectible account projection to $47.0 million for the projected test year. 6 Tr 2383.

The Commission finds that the Staff correctly removed PSCR revenue from the UCX calculation because it is not listed on the company's exhibit and correctly determined that "'any effort to adjust the expense level to reflect the projected revenue requirement is iterative [to the cost-of-service study] and should be avoided.'" December 1 order, p. 210 (citing PFD, pp. 522-523); *see also*, 6 Tr 4991. Additionally, the Commission adopts the Staff's recommended calculation that uses an average of historical years 2021 through 2023 rather than historical years 2020 through 2022, finding that it is appropriate to update the company's figures to those most currently available. *See*, 6 Tr 4991.

10. Electric Regulated Marketing Operations and Maintenance

DTE Electric projects an increase of $11.62 million above 2022 historical figures for a total projected test year of $32.2 million in electric regulated marketing O&M expenses, which includes C&I customer relationship management, EV marketing management, local economic development, DR portfolio costs, and Charging Forward O&M expense and regulatory asset amortization. The company calculates the 2025 projected figure by making increases to the 2022 historical figure, most significantly in the amount of $3.25 million for the company's EV program,

$2.96 million for its DR programs, and $3.51 million in Charging Forward amortization expenses. The company also calculates a blended rate of inflation at 2.90% for 2024 and 2025. 6 Tr 1986-1987; *see also*, Exhibit A-13, Schedules C5, C5.9.

The Staff recommends reducing regulated market O&M expenses by $292,000 for a total proposed regulated marketing O&M of $31.86 million, a figure that reflects the Staff's adjustment to the company's rate of inflation and is based on historical year 2023 rather than historical year 2022 as the company used. 6 Tr 1986, 4926-4927; *see also*, Exhibit S-7.4. In briefing, the Staff notes that the company did not rebut the Staff's revised figures. Staff's initial brief, p. 96.

No other parties express opposition to the company's projected figures with the exception of the use of the blended rate of inflation, which the Commission approves, as discussed above.

As with the adjustments to power generation O&M discussed above, the Commission finds it is appropriate to update DTE Electric's projection, which was based on historical year 2022, to a projection based on historical year 2023, as recommended by the Staff. Therefore, the Commission adopts the Staff's $292,000 adjustment to the company's regulated marketing O&M expenses.

11. Corporate Support

Two areas of corporate support O&M are contested in this case: IT O&M and corporate memberships. They are each discussed individually, below.

a. Information Technology Operations and Maintenance

The Staff recommends a disallowance of $2.5 million in certain IT O&M projects in the Level 2 and Level 3 categories. The Staff's recommended O&M disallowances are related to the Staff's recommended disallowances to the company's IT capital expenditures. 6 Tr 5112, 5117.

The Staff recommends a 20% disallowance for IT O&M costs related to 102 IT projects with Level 2 cost estimates. The Staff explains that it recommends these disallowances "due to their incomplete, imprecise, and indefinite nature." 6 Tr 5112. The Staff explains that:

> IT projects are given a Level 2 cost estimate more than a year before they are ready for implementation. Additional reviews, final approval, and budget allocation occur after projects are given a Level 2 cost estimate. Many things can happen between the time a project is given a Level 2 cost estimate and the year or more later at the time of execution including a change in scope, a change in schedule, the quote from the vendor, prioritization within the APC, or the necessity of the project altogether. These examples show the uncertainty of the costs associated with IT projects with Level 2 cost estimates. It is unfair to pass such uncertain expenses onto ratepayers.

6 Tr 5112-5113.

The Staff also discusses its concern over the disparity in Level 2 projects from Case No. U-21297 and projects now listed as Level 3 in the instant case. The Staff states that in:

> [a]nalyzing the Company's spreadsheet, Staff calculated the percent difference of the Level 2 and Level 3 project costs to range from -99.86% to 277.36% and found that of the 142 listed projects, only 24 projects had no change in cost. The Company over recovered costs on 75 of the projects, and the Company under recovered costs on 43 of the projects. Evaluating the 75 projects in which the Company over recovered from, the percent difference ranged from 0.11% to 99.86% with an average of 31.45% over-recovery. Evaluating the 43 projects in which the Company under recovered from, the percent difference ranged from 0.10% to 277.36% with an average of 37.28% under recovery.

6 Tr 5113.

The Staff notes that it recommended a 20% disallowance in DTE Electric's last two rate cases for the same reasons that it recommends a 20% disallowance in the instant case. The Staff notes that the Commission approved both recommendations. 6 Tr 5115-5116.

The Staff also recommends a 10% O&M disallowance in 104 IT projects that have Level 3 cost estimates because, according to the spreadsheet, the estimates are inaccurate. The Staff testifies that:

> [o]f the 125 projects listed (Staff removed 2 lines of the Oracle Forecasting Tool project as the Commission approved the disallowance of the investment in its December 1, 2023 Order), 121 of the projects had a spend year of 2022. The remaining 4 projects had a spend year of 2023. Analyzing the costs, Staff found that the percent difference of the costs ranged from -100% to 1269%. The Company over recovered on 70 of the 125 projects with an average percent over recovery of 38.31%. The Company under recovered on 55 of the 125 projects with an average percent under recovery of 86.31%. Three of the projects had an under recovery of over 500%. These are Production Growth (547.66%), Ransomware Protection (625.14%), and End of Life Asset Replacements (1269%). Without these three projects, the average percent under recovery decreases to 44.34%. Staff once again finds these cost variances to be concerning. According to the Company, Level 3 cost estimates are the most accurate cost estimate prior to actual costs; however, Staff's analysis demonstrates a significant discrepancy. The cost variance between Level 3 cost estimates and actual costs are not much more improved than the cost variance between Level 2 cost estimates and Level 3 cost estimates. Once again Staff emphasizes that the Company chooses to file a projected test year in its rate case application and has an obligation to make accurate expense requests. As projected, the Company may over recover costs for these IT projects, but the Commission is unable to perform retroactive ratemaking to correct for this issue. It is unfair to pass costs onto ratepayers without the assurance that its entirety will be used for the intended reasonable and prudent investment. If the Company spends more than 90% of the requested cost, they can always seek recovery in the next rate case.

6 Tr 5117-5118.

DTE Electric asserts that the Staff mistakenly used the IT O&M amount that supports all company IT users of the assets and that the correct IT O&M costs are about 74% of the costs, which is $1.8 million of the $2.5 million. DTE Electric's initial brief, p. 238; *see also*, Exhibit A-37, Schedule BB1. In its initial brief, the Staff agrees with DTE Electric on this point. Staff's initial brief, p. 100.

In its reply brief, DTE Electric reiterates that its projection was fully supported by its testimony and exhibits. DTE Electric's reply brief, p. 87 (citing 6 Tr 1512).

As discussed above with respect to capital expenditures, the Commission is persuaded that DTE Electric has not fully supported its projections for IT O&M and that, for the reasons stated by the Staff, there should be a 20% disallowance on IT O&M expenses for certain Level 2 projects and a 10% disallowance for IT O&M expenses for certain Level 3 projects after the 74% adjustment that was agreed to by the parties is made. The Commission finds the Staff's updated $1.828 million disallowance recommendation is supported in the record and is reasonable. *See*, Staff's initial brief, p. 100.

b. Corporate Memberships

DTE Electric testifies that certain corporate memberships for which the company pays $100,000 or more are non-discretionary as set forth on pages 1-2 of Exhibit A-27, Schedule Q1. The company states that it purchases 13 discretionary corporate memberships, which are listed on pages 3-7 of Exhibit A-27, Schedule Q1. The company argues that these 13 non-discretionary memberships specifically benefit customers by providing the company's various divisions with access to research, and providing information for performance benchmarking, best practices, and networking that provides an improved awareness of emerging technologies, industry trends, emerging issues, and available resources, as set forth in the exhibit and testimony. The company states that the figures on its exhibit are not adjusted for inflation; however, an adjustment for inflation was made when included in its revenue requirement. 2 Tr 100-102; *see also*, Exhibit A-27, Schedule Q1.

When compared to the corporate memberships included in the company's case presentation in Case No. U-21297, the company eliminated three memberships in this rate case: the Low-Carbon Resources Initiative, the U.S. Business Council for Sustainable Development, and the American Society of Employers. The company added one membership: the Center for Energy Workforce. *See*, Exhibit A-27, Schedule Q1, Case No. U-21534; Exhibit A-27, Schedule Q-1, Case No. U-21297.

Related to its membership in the Edison Electric Institute (EEI), the company testifies as follows:

> In addition to our operating groups (e.g., Distribution, Generation), the Company leverages EEI to the benefit of its customers through many of the Company's workstreams (e.g., IT, Supply Chain) as outlined below. EEI members are afforded the opportunity to establish connections with other companies through the EEI network. Some examples of how the Company's EEI participation benefits customers include:
> • Mutual assistance coordination across the nation which enables DTE Electric to quickly secure resources for storm restoration. The industry has no other mutual assistance structure;
> • Information on technology industry security initiatives and best practices;
> • Assistance identifying and networking with diverse suppliers specific to the utility industry as well as sharing best practices regarding supplier diversity;
> • Benchmarking on utility-driven economic development;
> • Knowledge building regarding FERC Order 2222 (addressing Distributed Energy Resource participation in electricity markets) and its implications for utility system preparation and operation;
> • Best practice sharing from transportation electrification programs around the nation; and
> • Learning from industry experts and leaders on important topical subjects such as battery operations and risk mitigation, decarbonization, and nonwire alternatives.

2 Tr 103.

The DAAOs oppose the recovery of non-discretionary corporate membership and industry association fees, stating that the "dues are not adequately justified in terms of benefits to ratepayers and, in some cases, are demonstrably contrary to ratepayer interests." 6 Tr 4388. The DAAOs quote their testimony from the December 1 order that the company should provide: "'(1) the specific achievements that each organization has accomplished that are in ratepayer interests, (2) specific information about each organization's governance structure, including whether and how its leadership is directly accountable to ratepayers, and (3) information about how each organization's interests and priorities have evolved over time.'" 6 Tr 4417-4418 (quoting December 1 order, pp. 219-220). They further quote the December 1 order finding that "'DTE Electric shall provide in its next general rate case a detailed description of how these organizations *specifically* impact/benefit customers as outlined by the DAAOs, which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization.'" 6 Tr 4418 (quoting the December 1 order, p. 221 (emphasis in original)).

The DAAOs argue that the company has fallen short of meeting the directive of the December 1 order in that the company's exhibit and related testimony describe the benefits the company may derive from its EEI membership but lack descriptions of the specific impacts and/or benefits for DTE Electric's customers. Further, the DAAOs argue that the organizations are "primarily geared towards companies." 6 Tr 4418.

Additionally, the DAAOs state that the company:

> did not provide more detailed and itemized information; it did not include a breakdown of the specific activities and benefits provided by each organization and clear explanations of the methodology used to allocate costs between recoverable and non-recoverable categories for each organization so that the Commission, intervenors, and ratepayers can understand how each of these entities' activities is appropriate and benefits ratepayers. DTE Electric removes lobbying percentages per the proportions that the organizations themselves report, which falls short of the detailed information necessary to fulfill the Commission's directive.

6 Tr 4419.

Also, the DAAOs testify that:

> some of DTE Electric's requested corporate membership expenses may be used for activities that are neither directly related to the provision of utility service nor beneficial to ratepayers and may even be contrary to the public interest. . . . [For example] EEI has taken a number of controversial and problematic positions on key energy policy issues, such as opposing the growth of distributed solar energy, supporting the rollback of federal clean air and climate regulations, and lobbying against state and local efforts to promote energy efficiency, renewable energy, and other clean energy solutions.

6 Tr 4420.

The DAAOs specifically oppose the company's EEI membership, averring that the organization serves many IOUs across the country and advocates policies that are beneficial to utilities but may be harmful to utility customers, as quoted above and further discussed in testimony. For example, the DAAOs assert that, the subjectivity of lobbying and nonlobbying activities makes it difficult for EEI and other organizations to remove all activities that have the effect of lobbying but are not specifically labeled as such. 6 Tr 4422-4427. The DAAOs state that, "'there is no practical way for the Company to review each activity and make a determination as to whether it constitutes lobbying.'" 6 Tr 4427 (quote attributed to the testimony of Xcel Energy, Inc., in Minnesota rate case *In re Xcel Energy Inc*., Docket Nos. G-002/GR-23-413, Bhosale Rebuttal Testimony (May 29, 2024) at 9).

Finally, the DAAOs argue that DTE Electric did not provide information on the governance of the organizations that would illuminate whether they are accountable to ratepayers and note that "DTE stated that it has no information about how their dues are allocated to EEI's different activities, has no part in decision-making about sponsorships, and has no way to verify that its membership dues do not fund sponsorships for events and conferences which the Commission attends." 6 Tr 4428; *see also*, 6 Tr 4420-4428.

For these reasons and others set forth in testimony, the DAAOs argue that DTE Electric's membership in the EEI does not benefit ratepayers and the $1.4 million in membership fees to the organization should be disallowed. 6 Tr 4430-4431. The DAAOs further recommend that the Commission should "[m]ake explicit in its order that failure to meet the requirements to demonstrate explicit ratepayer benefit as identified in Case No. U-21297 for any discretionary corporate membership will result in the rejection of cost-recovery." 6 Tr 4433.

In briefing, the DAAOs reiterate their case presentation and argue that the company's explanations of benefits to customers are short, vague, and generalized. DAAOs' initial brief, p. 75. In their reply brief, the DAAOs argue that, specifically, membership fees to the EEI should be disallowed because "it is impossible to determine whether EEI provides any benefit to customers at all or only causes harm to customers." DAAOs' reply brief, p. 24. The DAAOs argue that they want more detailed information on corporate memberships and that the Commission should ignore any claim by the company that the required information is too costly to obtain. DAAOs' reply brief, pp. 24-25.

In briefing, DTE Electric argues that Exhibit A-27, Schedule Q1, provides "specific customer benefits related to each of its corporate memberships." DTE Electric's initial brief, p. 240. DTE Electric also argues that "positions taken by industry organizations like EEI do not necessarily reflect the position of its member companies simply because those companies pay membership dues," but that "does not negate the benefits of EEI membership (access to benchmarking, best practices, networking, and research, as reflected by Exhibit A-27, Schedule Q1, p. 3) or provide sufficient justification to disallow the Company's proposed membership dues." DTE Electric's initial brief, p. 240. In its reply brief, the company reiterates that the DAAOs' proposals are without merit. DTE Electric's reply brief, p. 87.

The Commission finds that DTE Electric's corporate memberships projections for the projected test year are supported in the record and are reasonable. The company supplied additional evidence regarding how membership in these organizations provide benefits to customers and, therefore, demonstrates improvement over the information supplied in Case No. U-21297, sufficient to approve recovery of the projected test year amount. Additionally, the Commission agrees with DTE Electric that it need not agree with all of an organization's policies to reap benefits for its customers commensurate with the cost of membership. For example, the company testifies that the EEI provides "mutual assistance coordination across the nation which enables DTE Electric to quickly secure resources for storm restoration" that is unavailable from any other source. This assistance has proved invaluable to customers in restoring outages during and following severe weather. 2 Tr 103.

With respect to DTE Electric's membership and participation with the Center for Energy Workforce, the Human Capital Institute, and The Institute for Corporate Productivity, the Commission directs DTE Electric to provide detailed information sufficient to differentiate the benefits provided by these three organizations in its next general rate case to avoid duplication of services and benefits. Also in the company's next general rate case, the Commission directs the company to provide a discussion of actual processes, projects, procedures, or other tangible impacts benefitting the company's customers that have resulted from membership in these organizations.

c. Injuries and Damages

DTE Electric presents an Injuries and Damages O&M expense of $18.440 million. Exhibit A-13, Schedule C5.10. The company's projections use the actual expense for this category for the five-year period ended in 2022. *Id.*; *see also*, 6 Tr 1512.

The Staff recommends a $2.863 million reduction to the Injuries and Damages O&M expense, arguing that the company uses a normalization method approved by the Commission in Case No. U-21297 and previous rate cases, but that its method should be updated to include 2023. 6 Tr 4992; *see also*, Staff's initial brief, pp. 96-97. Including 2023 in the projection results in an Injuries and Damages expense of $15.577 million, or a $2.863 million decrease from the company's request of $18.440 million. 6 Tr 4992; Exhibit S-14.2; *see also*, Staff's initial brief, p. 97.

The Attorney General also recommends a $2.863 million reduction to the company's Injuries and Damages expense, arguing that the company relied on stale information to develop its projection and that its projection should be updated to include 2023. In her updated calculation using years 2019 through 2023, the Attorney General explains that Injuries and Damages expense has ranged from $5.0 million to $33.0 million, with an average of $15.577 million. 6 Tr 3694; Exhibit AG-42. Thus, the Attorney General mirrors the Staff's recommendation for an Injuries and Damages expense of $15.577 million. The Attorney General testifies that DTE Electric did not rebut her position. 6 Tr 3694.

DTE Electric did not provide rebuttal testimony or briefing on this issue.

The Commission finds that the Staff's and the Attorney General's suggested disallowance to the Injuries and Damages O&M expense is reasonable and should be adopted. The Staff and the Attorney General properly include the most updated years of historical expenses and utilize the normalization method approved in previous rate cases. *See*, 6 Tr 3694, 4992; Exhibits S-14.2, AG-42. Further, the company does not rebut the Staff's and the Attorney General's adjustment and does not provide any explanation as to why 2023 should not be included in its projections. Therefore, the Commission reduces DTE Electric's Injuries and Damages expense by $2.863 million, resulting in recovery of $15.577 million.

12. Pension and Benefits

As stated previously, this order addresses only contested issues between the parties. For issues that have not been disputed by the Staff or intervening parties, the Commission adopts DTE Electric's proposals as proffered. Relevant to the Pension and Benefits section of this order, the company's proposal for Pension, Other Post Employment Benefit Expenses, and New Hire Voluntary Employee's Beneficiary Association Expense were not disputed. Therefore, the Commission adopts the company's proposals as provided and supported on the record. *See*, 6 Tr 1498-1499, 2858-2859, 2922-2926; Exhibit A-13, Schedules C5.11, C5.12.1, and C5.12.2; *see also*, DTE Electric's initial brief, pp. 241-245.

a. Employee Savings Plan

Per DTE Electric, its employee savings plan (ESP) permits eligible non-represented employees and most represented groups to put aside a certain percentage of their annual salaries and wages, which the company matches up to 6%. Additionally, employees hired after the defined benefit pension plan closed to most new hires generally receive an additional employer contribution of 4% of annual salaries and wages, although certain employees receive an 8% contribution. *See*, 6 Tr 2859; *see also*, DTE Electric's initial brief, p. 246.

For the 2025 projected test year, the company requests recovery of $37.406 million for its ESP expense. 6 Tr 2860; Exhibit A-13, Schedule C5.11, p. 1; *see also*, DTE Electric's initial brief, p. 247. DTE Electric explains that it arrived at this figure by: "(1) normalizing the Company's recorded 2022 ESP expense, and (2) projecting this expense through the end of the projected test year (Exhibit A-13, Schedule C5.11, page 2, line 5, columns (c) and (h))." DTE Electric's initial brief, p. 247; *see also*, 6 Tr 2859-2860. For 2022, the company states that normalization was necessary because of an abnormally high level of employee resignations in 2021, likely driven by the transition out of the COVID-19 pandemic, that resulted in a high level of forfeitures in 2022. Removing the excess forfeitures of $0.378 million resulted in a 2022 ESP expenses of $30.77 million. 6 Tr 2860; Exhibit A-13, Schedule C5.11, p. 2.

The 2022 ESP was then increased by 7.5%, representing the four-year average increase in ESP costs between 2017 and 2020, and the company assumed to retain a constant proportion of costs capitalized through the test year.[38] 6 Tr 2860; *see also*, DTE Electric's initial brief, pp. 246-247. The company explains its reason for escalating the test year ESP expense by the average annual increase in ESP costs rather than by an increase in the ESP expense:

> Since the Company's [ESP] expense is impacted by the proportion of the costs that are capitalized, the annual changes in the Company's [ESP] expense reflects both the effect of the changes in costs and changes in the proportion of the costs capitalized. For example, the five-year average of the annual increase in [ESP] expense was 6.20% for the years 2018 through 2022, but this reflects an increase in the proportion of costs capitalized from 31.3% in 2017 to 39.6% in 2022. This increase in the proportion of costs capitalized reflects the significant increase in the Company's capital expenditures over this time frame, which is assumed to remain constant through the projected test year. Therefore, under the assumption that the proportion of costs capitalized will not increase in the future, the historical average annual increase in the Company's [ESP] costs of 7.50% for the years 2017 through 2020, as described in [previous testimony] is a more accurate measurement of the projected increase in the Company's [ESP] expense.

6 Tr 2861-2862.

The Staff recommends a $7.859 million reduction of the ESP expense citing disagreement with DTE Electric's projections. The Staff contends that an examination of the 2023 ESP expense showed a continuing downward trend demonstrating that the diminishing growth trend continues and the reason for excluding 2021 and 2022[39] from the annual average growth rate (AAGR) were not valid. The Staff explains how it calculated its own projections as follows:

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[38] DTE Electric explained in a footnote that 2021 and 2022 were excluded from the annual escalation because they were impacted by COVID-19, which was a one-time occurrence. Per the company, in 2021, DTE Electric experienced a low level of new employees and, in 2022, it experienced a high level of forfeitures due to the pandemic. DTE Electric states that its exclusion is consistent with the Commission's previous decision in the December 1 order. DTE Electric's initial brief, p. 246, n. 115 (citing December 1 order, p. 191).

[39] The Staff states in testimony and its initial brief that the company's exclusion of "2020 and 2021" were unreasonable. The Commission presumes this was a typographical error and the Staff intends the years "2021 and 2022" because the company's testimony and Exhibit A-13 as well as other areas of the Staff's initial brief and testimony state that 2021 and 2022 were the excluded years. *See*, 6 Tr 2860, 4993; DTE Electric's initial brief, p. 246; Staff's initial brief, p. 102.

> Staff used a five-year AAGR based on the Company's historic expenses. The annual change in ESP expense from years 2019-2023 produces a 4.06% AAGR. See Staff Exhibit S-14.4, line 7. The rate was applied to historic year 2023 resulting in a projection of $29,547,000[,] a reduction of $7,859,000 from the Company's projection of $37,406,000. See Exhibit S-14.3, line 1, and Exhibit S-14.0, line 3.

6 Tr 4993. Contending that it is proper to include the 2023 capitalization changes in the forecast to the benefit of the ratepayer, the Staff recommends a $7.859 million reduction from the company's position resulting in a recovery of $29.547 million in the ESP expense for the test year. Staff's initial brief, pp. 102-103.

In rebuttal, DTE Electric contends that the Staff's use of the 2023 ESP as a starting point is improper because the company capitalized an abnormally high proportion of ESP costs in 2023, which is not expected to occur again. 6 Tr 1575, 2908. Per DTE Electric:

> Given the financial challenges experienced by the Company in 2023, non-recurring reductions to O&M were made during 2023. This resulted in a higher proportion of related benefits to be capitalized than in a normal year. The Company is returning to a more standard level of O&M in 2024 and beyond. Therefore, a better forecast of benefits expense net of amounts capitalized would be based on the expense percentages from 2022.

6 Tr 1575.

The company states that, without providing a basis for doing so, the Staff used the 2022 percentage of Active Healthcare costs expenses at 60.4% rather than the 2023 percentage in arriving at its Active Healthcare expense in Exhibit S-14.3. *See*, 6 Tr 2946. The company notes that the Attorney General also used the 2022 proportion of Active Healthcare costs capitalized rather than 2023 proportion. *See*, 6 Tr 2908, 2951; *see also*, DTE Electric's reply brief, p. 89. However, the company presents an alternative:

> using the proportion of ESP costs capitalized in 2022 rather than the 2023 proportion, which is consistent with the Staff's use of the 2022 proportion of Active Healthcare costs. Exhibit A-35, Schedule Z2 updates Staff Exhibit S-15.4 by using the 2022 percentage of ESP expensed (60.4%) instead of the 2023 percentage

> (54.6%), resulting in adjusted 2023 expense of $2.901 million. Exhibit A-36, Schedule AA5 then uses this starting point and escalates it by 4.06% (as Staff did) resulting in a 2025 ESP expense of $32.688 million (a $3.141 million increase to Staff's projection).

DTE Electric's reply brief, pp. 89-90; *see also*, 6 Tr 2908-2909.

The Staff did not further address the issue in its reply brief beyond inclusion of its recommended $7.859 million disallowance in Appendix C to its reply brief. Staff's reply brief, Appendix C.

The Commission finds that DTE Electric's alternative ESP expense for the 2025 test year of $32.688 million is reasonable, supported, and should be adopted. In testimony and its exhibit, the company explains that the capitalized portion for 2023 was outside of the norm for the company's usual capitalized versus expensed proportions for ESP. Looking at Exhibit A-35, Schedule Z2, there appears to be a general trend of increasing the proportion of costs capitalized from 31.3% in 2017 up to 39.6% in 2022. However, the exhibit shows an increase to 45.4% capitalized in 2023, nearly a 6% jump as opposed to an average 1.54% increase between each year from the years 2017 to 2022. *See*, Exhibit A-35, Schedule Z4. The Commission finds there is support for the company's position that 2023 is an outlier year in terms of capitalized proportions and a reasoned basis for using the more normalized year of 2022 in its projection for the test year. Further, the Staff (and the Attorney General) rely on 2022 for the Active Healthcare expense, as pointed out by DTE Electric. *See*, 6 Tr 1561, 1575, 2955-2957, 2908, 2951; Exhibit S-14.3 (showing the expense percentage used for active healthcare as 60.4%, the 2022 proportion); Exhibit A-13, Schedule C5.11 (showing the 2022 expense percentage as 60.4%); *see also*, DTE Electric's reply brief, p. 89. The Staff does not rebut this point or provide further explanation as to why it is appropriate to use 2022 for some categories of O&M expenses but apply a different year for others. Absent a persuasive explanation, the Commission finds DTE Electric's approach to be reasonable.

The Commission also finds reasonable DTE Electric's approach to exclude 2021 and 2022 from the annual escalation because they were impacted by COVID-19, which was a one-time occurrence. DTE Electric's initial brief, p. 246, n. 115; *see also*, Exhibit A-13, Schedule C5.11. The administrative law judge in Case No. U-21297 agreed with the company in that case that the COVID-19 pandemic and its after-effect on employment trends was a one-time occurrence and justified an adjustment to its projections. *See*, Case No. U-21297, filing #U-21297-0621, p. 550. The Commission adopted the judge's reasoning and recommendation in the December 1 order. The Commission finds that the company's adjustment in the instant case is consistent with the December 1 order. *See*, December 1 order, p. 191.

Therefore, the Commission adopts an ESP expense of $32.688 million.

b. Active Healthcare Benefits

DTE Electric explains that its Active Healthcare Benefits expense consists largely of healthcare for employees (medical, dental, and vision benefits) and that the company projects this expense to increase from $50.126 million in the historical test year (2022), to $56.083 million in the projected test year (2025). DTE Electric's initial brief, p. 247; 6 Tr 2927; Exhibit A-13, Schedule C5.11.

To arrive at its projected costs, DTE Electric explains that it normalized the historical test year, 2022, with an adjustment of negative $1.260 million to account for the volatility of actual healthcare costs. 6 Tr 2927; DTE Electric's initial brief, p. 247. The increase includes the normalization of the 2022 costs to reflect a historical average of constant dollar costs, as developed on Exhibit A-13, Schedule C5.11.3, and annual escalations for the adjusted medical plan trend of increase by 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025. 6 Tr 2927. Per DTE Electric:

> annual unadjusted medical trend factors of 7.1% for 2023, 7.5% for 2024, and 7.0% for 2025 are based on projections for healthcare trends provided by the healthcare

> experts at Willis Towers Watson (WTW), as reflected on Exhibit A-13, Schedule C5.11.1. WTW's trend factors are reduced by 2.0% in 2023, 2.5% in 2024, and 3.0% in 2025 to reflect the expected savings from the Company's Wellness program (to 5.1% in 2023, 5.0% in 2024, and 4.0% in 2024 [sic: 2025]), and are corroborated by a study by PricewaterhouseCoopers LLP's (PwC) Health Research Institute (reflected on Exhibit A-13, Schedule C5.11.2), which projects that medical costs will increase by 6.0% in 2023, and 7.0% in 2024[.]

DTE Electric's initial brief, p. 248 (footnote omitted); *see also*, 6 Tr 2935-2938.

As to the changes in healthcare costs, the company attributes the reason for volatility in healthcare costs primarily to the company being self-insured for approximately 70% of its total active healthcare costs meaning that its costs are impacted by the mix and severity of medical treatments its employees (and eligible dependents) receive. 6 Tr 2928. The company testifies that the standard deviation measuring annual percentage change in these costs was 9.4% (with the annual percentage change of as high as 27.2% in 2021 and as low as negative 4.5% in 2018) and that to arrive at a more reliable starting point to determine projected healthcare expenses, the company uses a constant dollar normalizing method. 6 Tr 2929-2930; *see also*, DTE Electric's initial brief, p. 248. DTE Electric also contends that the pool of approximately 3,400 employees (and eligible dependents) is too small of a sample size with which to predict future healthcare trends and, therefore, the company uses the adjusted trend factors listed above based on national trends that are better at predicting future costs. 6 Tr 2927-2929, 2939-2940; *see also*, DTE Electric's initial brief, p. 248.

Speaking further to its constant dollar methodology, the company contends that its method is similar to converting historical nominal prices into real prices because inflation changes the value of a dollar over time. 6 Tr 2930-2933. DTE Electric states that, over the Attorney General's objections, the Commission adopted a similar approach in the May 8, 2020 order in Case

No. U-20561 (May 8 order) for the company's emergent replacement expenditures.[40] DTE Electric's initial brief, pp. 249-250. While DTE Electric acknowledges that the Commission rejected the constant dollar normalization method in the December 1 order, citing concerns about compounded inflationary increases, the company argues that its use here applies the same logic as its application to emergent replacements. Per the company:

> It merely recasts the Company's historical Active Healthcare costs for the impact of historical medical cost escalations. The only difference is the use of medical cost trends rather than overall inflation, which is appropriate in this medical cost context. The end result is the same, which is the creation of an accurate starting point to be used to project future costs[.]

DTE Electric's initial brief, p. 250; *see also*, 6 Tr 2934-2935.

The Staff recommends reducing the company's Active Healthcare O&M expense by $2.334 million, resulting in a total expense of $53.749 million, citing the Commission's consistent rejection of the constant dollar adjustment method. 6 Tr 4993; *see also*, Staff's initial brief, p. 103. Contrary to the company's claims, the Staff argues that the WTW national healthcare trends are not reflective of the volatility in DTE Electric's healthcare expense history. The Staff explains the company's AAGR for total healthcare costs is 4.83% and that DTE Electric's use of a blended rate of inflation unnecessarily conflates the projection method with the constant dollar adjustment to the historic test resulting in an excessive projection. 6 Tr 4994.

The Staff describes its projection method as follows:

> Staff requested total healthcare expense and employee headcount for 2023. Then a per person AAGR of 4.83%, calculated from the Company's own change in Active Healthcare was applied to its unadjusted historic test year total expense to project it forward. The total projected cost is multiplied by the Company's expense

[40] DTE Electric adds that the Commission continued the constant dollar treatment for emergent replacements in the November 18 order and December 1 order. DTE Electric's initial brief, pp. 249-250.

> percentage as a portion of it is capitalized. This is presented on Exhibit S-14.3, line 6 and results in an Active Healthcare expense projection of $53,749,000.

6 Tr 4994; *see also*, Exhibits S-14.3 and S-14.4.

In rebuttal to the Staff's position, DTE Electric contends that the Staff's method is flawed because it relies on a single year of the company's Active Healthcare cost as a starting point (rather than the constant dollar normalized starting point) and uses a historical average of the actual annual percent changes in healthcare costs (rather than the projected medical trend rates). 6 Tr 2947. DTE Electric then points out that the Staff included a one-time credit from its Pharmacy Benefit Manager (PBM) in 2023 that reduced its Active Healthcare expense by $1.134 million. As a correction to the Staff's projection, the company contends that this credit should be excluded from the 2023 healthcare costs used to determine the starting point and historical average annual escalation rate because this is a non-recurring item. 6 Tr 2947. Accordingly, in Exhibit A-36, Schedule AA1, the company provides a recalculation of the Staff's analysis in Exhibit S-14.4 that includes an adjustment for the one-time credit. Per DTE Electric, excluding the $1.134 million credit increases the 2023 active healthcare costs to $82.109 million or a cost per employee of $12,541, which increases the five-year average annual change to 5.11%, as opposed to the Staff's 4.83% five-year average. 6 Tr 2948. Citing an updated Exhibit A-36, Schedule AA5 with the company's rebuttal adjustments and an adjusted 2023 expense of $49.589 million, the company applies the 5.11% escalation rate for 2024 and 2025 to arrive at an update Active Healthcare expense of $54.784 million. 6 Tr 2948; *see also*, Exhibit A-36, Schedule AA5.

The Staff contends that the one-time credit should be applied to the benefit of the ratepayer and maintains its proposed reduction to the active healthcare expense. Staff's initial brief, p. 104. In its reply brief, the Staff disagrees with DTE Electric's representation of its recalculations in rebuttal as "corrections." Staff's reply brief, p. 5. The Staff contends that its inclusion of the $1.134 million credit was not in error. Referencing the company's similar response regarding the General Benefits and Benefit Administration issue, discussed below, the Staff argues that its methods were intentional, and the company's increased capitalization of expenses should be reflected in AAGR models. Per the Staff:

> The Company should not benefit at the expense of the ratepayer by simultaneously receiving a larger rate base and a higher O&M expense projection by excluding the increased capitalization percentage from expense projections. While Staff is cognizant of the adversarial process, the Company misleadingly presented it recommendations for Staff's adjustments as "corrections" when they are not. This goes beyond the attempt to persuade and patently mischaracterizes the Company's suggestions.

Staff's reply brief, p. 6.

The Attorney General advocates for a reduction of $3.1 million to DTE Electric's Active Healthcare O&M expense citing two problems with the company projection and its forecast approach: (1) the company continues to apply inflationary factors to historical costs, and (2) the company uses national health care cost trend rates of 7.0% to 7.5% adjusted down to cost increase rates of 4.0% to 5.1% to forecast future health care costs instead of using the historical healthcare expense increases actually experienced by the company. *See*, 6 Tr 3695. The Attorney General contends that the company's method unnecessarily inflates projected expenses in the test year.

Using the company's Exhibit A-13, Schedule C5.11.3, the Attorney General projects the Active Healthcare test year expense to be $52.9 million and explains her methodology:

> From the 2017 to 2022 data, [the Attorney General] calculated the average rate of increase in healthcare costs of 3.33%. Using this annual rate of increase and applying it to the latest actual costs from 2023, [the Attorney General] calculated the projected test year expense of $52.9 million. This expense amount excludes the portion of health care costs that are capitalized. The $52.9 million is a reasonable forecast of health care expenses for the projected test year based on actual cost trends, in contrast with the Company's artificially derived expense of $56.1 million.

6 Tr 3696; *see also*, Exhibit AG-43.

In rebuttal, the company disagrees with the Attorney General's projection, namely her opposition to and characterization of the company's constant dollar normalization adjustment. The company argues that the Attorney General's description of the method as an increase that is divorced from reality demonstrates her misunderstanding of the concept. The company references and incorporates its testimony explaining the constant dollar adjustment. Next, DTE Electric argues that:

> [the Attorney General] proposes to use the historical increase in the Company's Active Healthcare costs from 2018 through 2022, yet incongruously uses the 2023 adjusted Active Healthcare expense for the basis of determining the Active Healthcare expense for the projected test year. . . . [T]he use of historical increases in the Company's Active Healthcare costs continues to be a poor predictor of the Company's future Active Healthcare costs rather than projected medical trends[.]

6 Tr 2949. The company further explains that, while it disagrees with using the historical annual changes, there is no basis for excluding the most recent historical data from 2023 when using a historical period to develop the annual percentage change, and that doing so has a material impact on the five-year average.

> Exhibit A-36, Schedule AA2 reflects the Company's Active Healthcare costs per employee for each of the years 2017 through 2023, with the 2023 amounts adjusted for the one-time PBM credit discussed above. This schedule shows that the five-year average change in the Company's Active Healthcare costs is 5.11% for the years 2019 through 2023 but is only 3.96% for the years 2018 through 2022, or a difference of 29.0%. While [the Attorney General] describes the 3.33% historical percentage change [she] has developed as the "annual rate of increase" (Coppola Direct, page 113, lines 7-8), it is strikingly close to the compound annual growth rate of 3.35% in Active Healthcare costs between the years 2017 and 2022. In contrast, the compound annual growth rate between the years 2018 and 2023 is 4.56%, or a difference of 36.3%. The arbitrary inclusion of the Company's Active Healthcare costs for 2017 and the exclusion of 2023, as proposed by [the Attorney General], results in a dramatic understatement of both the average of the annual increase for the five years and the compound annual growth rate.

6 Tr 2950. As a correction to the Attorney General's projection, the company states that the Attorney General's projection should reflect the updated five-year average of annual changes in active healthcare costs of 5.11%, as shown in Exhibit A-36, Schedule AA5, resulting in a projected test year expense of $54.784 million. Exhibit A-36, Schedule AA5; *see also*, DTE Electric's reply brief, pp. 91-92.

In its reply brief, the company repeats its disagreement with the Attorney General and states that any savings for 2025 resulting from the Voluntary Separation Incentive Program (VSIP) are speculative and points to Exhibit AG-45 in which the company explains that 2025 savings could materialize but that the estimate will evolve due to the need to fill many key roles and that the savings do not include offsets to any program costs. DTE Electric's reply brief, p. 91 (citing Exhibit AG-45).

The Attorney General responds that normally she would agree with the company's position that 2023 actual health care expenses should be used with the 5.11% average rate of increase but that doing so is not warranted here because, in 2024, the company undertook a significant workforce reduction, which reduced labor costs and employee benefits costs. The Attorney General points out that DTE Electric identified $5.8 million in employee benefit savings for 2025 with a large portion pertaining to healthcare costs that were not included in the company's projected test year exhibits. Attorney General's initial brief, p. 70; Exhibit AG-45. Thus, the Attorney General contends that the lower rate of 3.33% provides a more reasonable forecast of healthcare expenses in the test year. Attorney General's initial brief, p. 70.

Responding to DTE Electric's insistence on using the constant dollar adjustment to establish an accurate starting point because the volatility of healthcare expenses makes any historical period unreliable, the Attorney General contends that the company's "convenient" position allows it to increase costs. As to the exclusion of 2023, the Attorney General points back to her arguments in her initial brief and maintains her position. Attorney General's reply brief, pp. 38-40.

As discussed above in Section V.B.4.b.i. regarding Historical Inflation and Blended Inflation Rate, the Commission declines to adopt DTE Electric's constant dollar averaging method for projecting Active Healthcare expenses. The Commission will not repeat its reasoning but herein incorporates the discussion *supra*.

The Commission also declines to adopt the company's use of the national health care trend. DTE Electric testifies that in using the data from WTW it adjusts WTW's trend factors by 2.0% in 2023, 2.5% in 2024, and 3.0% in 2025 to reflect the expected savings from the company's Wellness program (to 5.1% in 2023, 5.0% in 2024, and 4.0% in 2024). 6 Tr 2935-2938. However, as shown in the Staff's Exhibit S-14.4, the WTW's year-to-year adjustments do not reflect the changes experienced by the company. Exhibit S-14.4.

The company further contends that the pool of participants enrolled in its Active Healthcare benefits does not constitute a large enough sample size with which to judge changes in its healthcare costs. *See*, 6 Tr 2927-2929, 2939-2940. The Commission is not persuaded of this and finds that evaluating the actual expenses and year-to-year changes experienced by the entire pool of employees provides a more reliable indication of future expenses than national trend data. The company's presentation of its range of year-to-year changes substantiates this point. *See*, 6 Tr 2929, Table 1. The Commission finds that rejection of the national healthcare trend for use in the company's projections is also consistent with the Commission's previous decision in the December 1 order. *See*, December 1 order, p. 232.

Additionally, the Commission is not persuaded that the company's projections represent the most reasonable forecast of test year expenses when the company has not made any adjustment for the savings associated with the VSIP, discussed *infra* in Part XI.D. of this order. *See*, Exhibit AG-45. The Commission understands that the company attests that the 2025 VSIP savings are estimates that are subject to change, but the complete omission of the anticipated savings lends support to the Attorney General's argument that the company has inflated its O&M expense projections. *See*, Exhibits AG-45 and AG-1.52 Confidential.

Ultimately, the Commission finds that the Staff's position represents the most reasonable and supported projection for the 2025 Active Healthcare expense that is consistent with the Commission's past approvals. The Attorney General's method using a similar average annual change percentage is similar but omits the use of 2023. The Attorney General explains that normally she would agree with the company's suggested inclusion of 2023 and its revised 5.11% AAGR but the company's omission of the VSIP negates that position. Attorney General's initial brief, p. 70; Exhibit AG-43. The Commission fails to see why the company's VSIP savings omission weighs on the decision to use historical years 2018 through 2022, rather than the more recent 2019 through 2023. As such, the Commission agrees with the Staff's reliance on historical years 2019 through 2023.

Further, having rejected the constant dollar averaging method and the use of national data trends, the Commission finds the Staff's projections based on the AAGR from the years 2019 through 2023 to be the most reasonable. DTE Electric's remaining rebuttal to the Staff's adjustment consists of its argument that the Staff omitted a one-time credit that the company received in 2023. *See*, 6 Tr 2947. Given the company's omission of any estimated healthcare savings resulting from the VSIP, the Commission finds that the one-time credit should be included in 2023 to the benefit of ratepayers and results in a more reasonable projection of test year expenses.

Therefore, the Commission adopts the Staff's reduction of $2.334 million, resulting in a total Active Healthcare expense of $53.749 million.

c. Other Employee Benefit Costs

DTE Electric explains that its Other Employee Benefits expense includes benefits such as Accrued Vacation, Supplemental Severance Plan, Wellness Plan, Long-Term Disability expense, costs associated with the Affordable Care Act (ACA), Medical Refund Amortization, O&M project reimbursements General Benefits expenses, Executive and Supplemental Retirement Plans, Supplemental Savings Plan (SSP), Deferred Compensation Plan, and Retirement Administration Fee. 6 Tr 2862, 2940-2943; Exhibit A-13, Schedule C5.11; *see also*, DTE Electric's initial brief, p. 252. The company projects its Other Employee Benefits expense to increase from $5.318 million in 2022, to $18.554 million in the 2025 test year consisting of $11.7 million in normalization adjustments and $2.067 in projected increases. 6 Tr 2862, 2940; Exhibit A-13, Schedule C5.11; *see also*, DTE Electric's initial brief, p. 252.

The contested portions of the Other Employee Benefits expense include the General Benefits expense, the Benefits Administration Fees, and the SSP. *See*, Staff's initial brief, pp. 104-106; Attorney General's initial brief, pp. 71-72.

i. General Benefits Expense

DTE Electric projects a General Benefits expense of $2.395 million for the test year. The company explains that its projection is based on the actual 2022 expense of $2.198 million escalated at the overall rate of inflation as measured by the Consumers Price Index. 6 Tr 2942.

The Staff proposes a $1.344 million decrease in the General Benefits expense, arguing that for five consecutive years there has been a decrease in this expense category. Thus, the negative five-year AAGR makes it inappropriate to use general inflation to escalate this expense. The Staff argues that allowing the escalation based on inflation disincentivizes the company from continuing to reduce costs. 6 Tr 4995. The Staff recommends using the AAGR based on a five-year average for projecting the General Benefits expense. For General Benefits, the Staff calculates a negative 10.24% AAGR, which when applied to the 2023 expenses provided to the Staff, results in a projected 2025 test year expense of $1.051 million, a $1.344 million decrease from the company's position. 6 Tr 4995-4996; Exhibit S-14.4; *see also*, Staff's initial brief, p. 105.

In rebuttal, the company opposes the Staff's projection, alleging that it contains four flaws: (1) because it is based on the 2023 expense, it ignores two one-time items that reduced the company's expense in 2023, namely suspending the tuition reimbursement and employee service anniversary awards for reductions of $629,000 and $651,000, respectively; (2) by using the 2023 actual expense in 2023, unadjusted for the two one-time expense reductions, the five-year average of the annual change in the General Benefits expense is understated; (3) the Staff calculated the negative 10.24% AAGR based on the annual percent change in the company's General Benefits expense rather than the General Benefits costs which is undistorted by changes in the proportion of costs capitalized; and (4) because the Staff uses the 2023 actual proportion of General Benefits costs capitalized, which was distorted by the impact of O&M reductions implemented in 2023, the projected expense is understated and 2022 is more representative of the proportion allocated to expense. 6 Tr 2951-2954; *see also*, DTE Electric's initial brief, p. 254.

DTE Electric contends that if the Commission opts to use the Staff's methodology, the Staff's method should be corrected to include the impacts of the two one-time adjustments, which amounts to a $1.280 million increase to the total General Benefits costs in 2023. 6 Tr 2954. This in turn increases the five-year average of the historical average annual change in General Benefits costs to negative 0.51%, rather than the Staff's negative 10.24%. This adjustment increases the company's 2023 General Benefits expense by $826,000, resulting in an adjusted 2023 General Benefits expense of $2.262 million. 6 Tr 2954; Exhibit A-36, Schedule AA3. Beginning with the $2.262 million and escalating this amount by the five-year average of the annual change of negative 0.51% for 2024 and 2025, the company updates its General Benefits expense for the projected test year to $2.239 million. 6 Tr 2954-2955; Exhibit A-36, Schedule AA5.

In its initial brief, the Staff repeats its position and contends that its AAGR considers changes in capitalization rates for all years because it utilizes the actual expense the company booked. Staff's initial brief, pp. 104-105. In its reply brief, the Staff responds to the company's correction of the Staff's projection method as follows:

> Staff's method was intentional and with purpose. The Company's increased capitalization of expenses should be reflected in average annual growth models. The Company should not benefit at the expense of the ratepayer by simultaneously receiving a larger rate base and a higher O&M expense projection by excluding the increased capitalization percentage from expense projections.

Staff's reply brief, p. 6. Further, the Staff opposes the company's characterization of its changes to the Staff's method as a correction and contends that the company should not mislead the Commission by presenting its opposing recommendations as corrections. *Id*.

The Commission finds that DTE Electric's alternative proposal of 2025 test year General Benefits expense in the amount of $2.239 million represents a reasonable calculation and should be approved. The Staff advocates for a general benefits expense calculated using a negative 10.24% AAGR and based on the 2023 actual general benefits expense. *See*, 6 Tr 4995-4996; Exhibit S-14.4. The company counters that the Staff's method is flawed because it includes two one-time expenses for 2023 that had reduced the company's 2023 expenses and used the 2023 actual proportion of costs capitalized, which is inconsistent with the Staff's use of the 2022 actual proportion of costs capitalized for the active healthcare expense. 6 Tr 2951-2952. While the

Commission agrees with the Staff's observation that the company's General Benefits expense has seen an overall decrease in the past five years, the Commission finds reasonable the company's argument to account for the two one-time reductions in 2023 and to use the 2022 actual proportion of costs capitalized. *See*, 6 Tr 2951-2955; Exhibit A-36, Schedule AA3.

DTE Electric explains that in 2023, the company suspended its tuition reimbursement program for employees pursuing higher education and eliminated its employee service anniversary reward. The company attests that these reductions were part of temporary cost reductions due to financial challenges in that year. 6 Tr 2952. Due to the temporary nature of these reductions, as testified to by the company, and the presumed reinstatement of these programs, the Commission finds that the company's recalculation of the Staff's position is reasonable. *See*, 6 Tr 2952. As to the use of the 2023 proportion of costs capitalized, the Commission finds DTE Electric's testimony persuasive that it is more appropriate to use the more normalized 2022 actual proportion of costs capitalized which is also consistent with the Staff's calculation of the active healthcare expense. *See*, 6 Tr 1561, 1575, 2953-2954; Exhibit S-14.3 (showing the expense percentage used for active healthcare as 60.4%, the 2022 proportion); Exhibit A-13, Schedule C5.11 (showing the 2022 expense percentage as 60.4%). The Staff did not respond to or explain the rationale for using the 2022 proportion of costs capitalized for active healthcare but the 2023 proportion for the general benefits expense. Absent any rationale by the Staff, the Commission finds DTE Electric's argument persuasive.

Therefore, the Commission adopts DTE Electric's alternative proposed General Benefits expense of $2.239 million for the test year.

ii. Benefits Plan Administration Fees

DTE Electric projects its benefits plan administration fees to be $7.296 million based on the projected overall inflation rate assumptions. 6 Tr 2943; Exhibit A-13, Schedule C5.11.

The Staff proposes a $2.855 million decrease to the administration fees expense, arguing that, while there is some volatility year-to-year in the expense amount, the negative five-year AAGR makes it unreasonable to use inflation to increase this expense. The Staff argues that allowing the escalation based on inflation disincentivizes the company from continuing to reduce costs. 6 Tr 4995. The Staff recommends using the AAGR based on a five-year average for projecting the administration fees expense. For the administration fees, the Staff calculates a negative 5.57% AAGR, which results in a projected 2025 test year expense of $4.708 million, a $2.855 million decrease from the company's position. 6 Tr 4995-4996; Exhibit S-14.4; *see also*, Staff's initial brief, pp. 105-106.

In rebuttal, DTE Electric contends that the Staff's projection is flawed in two ways: (1) the Staff's five-year average of the annual change in the administration fees is based on the fees expense, after the reduction for the proportion capitalized, which is distorted by the proportion of the total benefit administration fees that are capitalized; and (2) the Staff's projection is based on the 2023 benefit administration fees expense that was distorted by one-time O&M reductions. 6 Tr 2955. The company presents and explains its revised calculation based on the Staff's methodology:

> Exhibit A-36, Schedule AA4 reflects a restatement of Benefit Administration Fees on Staff Witness Rueckert's Exhibit S-14-4, which develops a five-year average of the annual percent change in the Benefit Administration Fees costs, unadjusted for the proportion of costs capitalized, of negative 3.66%, compared to Staff Witness Rueckert's five-year average of the changes in the Benefit Administration Fees of negative 5.57%. This schedule also adjusts the Benefit Administration Fees expense in 2023 of 54.8% to the 2022 proportion Benefit Administration Fees allocated to expense of 60.1%[. . . .]

6 Tr 2956; Exhibit A-36, Schedules AA4 and AA5. DTE Electric's adjustment of the Staff's methodology results in a projected test year expense of $5.372 million. DTE Electric argues that its revised benefits administration fees five-year annual percent change is consistent with the Staff's method for Active Healthcare projections in that the Staff used the 2022 proportion of costs capitalized for Active Healthcare. 6 Tr 2957; *see also*, DTE Electric's initial brief, pp. 254-255; *see also*, DTE Electric's reply brief, pp. 92-94.

Responding to the company's assertions that the one-time reductions to its benefits distorted the 2023 expense, the Staff argues that the company's argument does not negate the negative expense trend in DTE Electric's benefits administration fees expense. The Staff asserts that reducing expenses should be to the benefit of the ratepayer and included in future rate cases. Staff's initial brief, p. 106. The Staff also opposes DTE Electric's characterization of its revised expense presented in its rebuttal testimony as a correction and contends that doing so is misleading. The Staff repeats that the company should not benefit at the expense of the ratepayer by simultaneously receiving a larger rate base and a higher O&M expense projection by excluding the increased capitalization percentage from expense projections. Staff's reply brief, p. 6.

The Commission finds that DTE Electric's alternative calculation presented in Exhibit A-36, Schedule AA4, resulting in a Benefits Administration expense of $5.372 million for the projected test year is reasonable and should be approved. *See*, 6 Tr 2955-2957; Exhibit A-36, Schedule AA4.

Similar to the Commission's reasoning set forth above pertaining to the General Benefits expense, the Commission finds DTE Electric's arguments persuasive. DTE Electric contends that the Staff's calculation relies on the proportion of costs capitalized for 2023, rather than 2022 which it used for Active Healthcare costs. *See*, 6 Tr 1561, 1575, 2955-2957; Exhibit S-14.3

(showing the expense percentage used for active healthcare as 60.4%, the 2022 proportion); Exhibit A-13, Schedule C5.11 (showing the 2022 expense percentage as 60.4%). The Staff did not respond to or explain the rationale for using the 2022 proportion of costs capitalized for active healthcare but the 2023 proportion for the general benefits expense. Absent any rationale by the Staff, the Commission finds DTE Electric's argument persuasive. Further, the Commission finds that it is reasonable for DTE Electric to account for the one-time reductions in 2023, as the company explains that these reductions were temporary and thus will be reinstated for the 2025 test year. *See*, 6 Tr 1561, 1575, 2955-2957.

iii. Supplemental Savings Plan

DTE Electric explains that the SSP is a non-qualified benefit plan that does not meet the requirements under the Internal Revenue Code to be eligible for certain tax advantages but that allows company employees at the director level or above whose compensation has exceeded the annual contribution limits for tax advantaged accounts to contribute to a savings plan. 6 Tr 2863. The company seeks recovery of $6.055 million for the SSP expense in the test year. 6 Tr 2864; Exhibit A-13, Schedule C.5.11.

Per DTE Electric:

> The SSP normalization adjustment reflects an annual return on the investments of 6.80% in 2022, which is based on the ERoA [expected return on assets] used in the determination of the Company's pension costs in the historical test year. This results in a normalized SSP expense of $2.456 million compared to a negative expense of $3.599 million recorded in 2022, which represents an increase in SSP expense of $6.055 million, as reflected on page 2 of Exhibit A-13, Schedule C5.11, line 15, column (c). The increase in SSP expense reflects the difference between the negative return on the investments in the SSP 12 and the ERoA of 6.80%.

6 Tr 2864. The company explains that it proposes a normalization adjustment of the actual 2022 expense and an increase in the projection from a normalized 2022 expense of $2.456 million to $3.207 million to reflect an increase in the company's matching contributions based on projected

salary escalations and an increase in the expected earnings on designated investments. 6 Tr 2864; Exhibit A-13, Schedule C5.11; *see also*, DTE Electric's initial brief, p. 252. The company's projection reflects an annual return on the investments of 7.60% in 2023, 7.90% in 2024 and 7.80% in 2025, consistent with the expected return on assets used in the determination of the company's pension costs in the projected test year. 6 Tr 2864.

The Attorney General recommends a total disallowance of $3.207 million of the SSP expense. 6 Tr 3696-3697; Attorney General's initial brief, p. 71. The Attorney General argues that the SSP is available to only a limited number of highly paid employees and that ratepayers should not pay for costs benefiting only a few employees. The Attorney General compares the SSP to the supplemental employee retirement plan (SERP) that the Commission previously rejected. 6 Tr 3697.

In rebuttal, the company argues that the Attorney General's disallowance should be rejected because her characterization of the SSP is incorrect and ignores the Commission's previous approval of SSP cost recovery. 6 Tr 2863, 2909-2910; DTE Electric's initial brief, pp. 252-253. In support, the company points to the December 23, 2008 order in Case No. U-15244 (December 23 order) and the April 18, 2018 order in Case No. U-18255 (April 18 order) where the Commission authorized recovery for the SSP. 6 Tr 2910-2911; DTE Electrics' initial brief, p. 253 (citing December 23 order, p. 34, and April 18 order, p. 52). The company maintains that the nature of this expense has not changed such that recovery is now no longer appropriate. DTE Electric's initial brief, p. 253. The company argues that the Attorney General also ignores that the SSP provides the same benefits as those under the Qualified Savings Plan. 6 Tr 2910. The company repeats its position in its reply brief. DTE Electric's reply brief, pp. 92-93.

Responding to the company's rebuttal, the Attorney General repeats that the SSP is available only to a subset of highly compensated employees and argues that the fact that these employees earn so much they are not eligible for the employee savings plan shows the similarity to the SERP rejected by the Commission. The Attorney General also points out the Commission's observation in the April 18 order that the acronyms for these types of benefit plans continually change making it difficult to track. Therefore, the Attorney General contends that past approvals by the Commission should be given less weight when the specifics of the company's requested recovery are inconsistent. Attorney General's initial brief, pp. 71-72 (citing April 18 order, p. 52).

DTE Electric and the Attorney General repeat their positions and arguments in their respective reply briefs. DTE Electric's reply brief, pp. 92-93; Attorney General's reply brief, p. 40.

The Commission finds that DTE Electric's request for recovery of the SSP expense is reasonable and prudent and supported by persuasive evidence on the record. The Commission is not convinced by the Attorney General's arguments that the SSP should be disallowed because it is available to a limited number of highly paid employees. The Attorney General's characterizations are vague in that she does not define what she considers to be "highly paid" or an acceptable compensation threshold with which the SSP would be a reasonable benefit. *See*, 6 Tr 3696-3697. The Attorney General also draws comparisons to the SERP but gives no further explanation as to the similar characteristics between the two programs that would warrant disallowance. *See*, 6 Tr 3697. In sum, the Attorney General's arguments do not outweigh the Commission's previous approval of the SSP. *See*, April 18 order, p. 52. The Commission acknowledges that its previous direct approval of the SSP as a contested issue was in 2018; however, the SSP has been requested for recovery in DTE Electric's more recent rate cases, Case Nos. U-20836 and U-21297, but was not contested in either case. As such, the April 18 order remains on point and DTE Electric demonstrated in this case holds that the nature of the SSP remains the same such that approval remains reasonable and prudent. *See*, 6 Tr 2863, 2909-2910; Exhibit A-13, Schedule C5.11.

13. Employee Compensation

In testimony, DTE Electric explains its philosophy and methods for determining employee compensation in general. 6 Tr 2867-2875. As to the employee incentive compensation plans (EICPs) for executive and non-executive employees at issue here, the company states that its programs consist of its Annual Incentive Plan (AIP) (applicable to senior management employees), Rewarding Employees Plan (REP) (available to all other non-represented employees), and the Long-Term Incentive Plan (LTIP), which is a multiple-year incentive plan generally available to managers and above, and up to 10% of other non-represented employees. 6 Tr 2875-2897; Exhibit A-21, Schedules K1 through K6; DTE Electric's initial brief, pp. 255-256.

The company proposes to recover $59.504 million in projected test period incentive compensation expense, which excludes incentive compensation expenses for its top five executives. 6 Tr 2875-2876. The company provides the components of its EICP expense as follows:

	LTIP	AIP	REP	Total
		(000's Omitted)		
Financial				
DTE Electric	$5,858	$615	$7,029	$13,502
Nuclear Gen	1,395	92	839	2,326
DTE LLC	13,154	3,509	6,741	23,404
	20,408	4,215	14,609	39,232
Operating				
DTE Electric	0	504	5,758	6,262
Nuclear Gen	0	200	2,527	2,727
DTE LLC	0	3,862	7,420	11,281
	0	4,566	15,705	20,271
Total				
DTE Electric	5,858	1,119	12,787	19,764
Nuclear Gen	1,395	292	3,367	5,054
DTE LLC	13,154	7,370	14,161	34,686
	$20,408	$8,781	$30,315	$59,504

6 Tr 2889.[41]

According to DTE Electric, the operating measures of the AIP and REP relate to Customer Satisfaction, Safety and Engagement, and Operating Excellence, specifically described as follows:

> Customer Satisfaction measures are intended to focus employees on improving the experience that customers have in their interactions with the Company. Safety and Engagement measures encompass employee engagement as measured by the Gallup survey and employee safety. Operating Excellence includes measures related to generation and distribution reliability, as well as additional specific measures related to the nuclear generation business unit[.]

DTE Electric's initial brief, p. 256; *see also*, 6 Tr 2882-2886. The company also explains the financial measures included in the AIP, the company's operating excellence measures, the operating measures applicable to the Nuclear Generation business unit, and the fact that the DTE LLC AIP and REP represent plans for corporate staff providing services to DTE Electric. *See*, 6 Tr 2882, 2884-2887.

[41] "DTE LLC" refers to DTE Energy Corporate Services, LLC.

As to the LTIP, DTE Electric explains that:

> The LTIP provides the opportunity for certain individuals to receive retention-oriented or performance-based rewards delivered via shares of DTE Energy common stock, either Performance Shares, which are based on the achievement of multi-year performance objectives, or through Restricted Stock. Currently, 70% of the value of awards for executives and directors is through grants of Performance Shares and 30% of the value of awards is through Restricted Stock, while 100% of the awards to other eligible employees are through Performance Shares.

6 Tr 2887. DTE Electric also explains the performance share measures as follows:

> These measures generally reflect the long-term financial performance of DTE Energy and are intended to motivate employees of the individual operating companies, such as DTE Electric, to keep in mind the role of their own contributions to the overall long-term success of DTE. Accordingly, the predominate measure for DTE Electric and DTE LLC (80% for both) is the total return to DTE Energy shareholders (i.e., capital appreciation and dividends) relative to a group of peer companies over the next three years. The second financial measure included in the LTIP, which contributes 20% to the total weighting, is DTE Energy's three-year cumulative Operating Earnings per Share. The three-year focus of the performance-based measures is designed to motivate decisions and actions that produce sustainable benefits rather than short-term actions that may entail long-term risks.

6 Tr 2888.

Noting that the Commission has previously indicated that inclusion of incentive compensation in the revenue requirement requires a showing that the incentive compensation programs provided benefits to customers in excess of the expense, DTE Electric contends that its analysis showed an aggregate benefit of $104.478 million, which exceeds the total incentive compensation expense of $59.504 million by $44.974 million. The company also explains how it calculated these benefits. 6 Tr 2891-2896; Exhibit A-21, Schedule K6.

The company then testifies that in Case No. U-20836, the Commission approved recovery of $12.7 million for EICP assuming the company achieved 60% of its targeted metrics and approved deferral treatment above or below the base amount, up to a maximum 100% target level, to be refunded or recovered in DTE Electric's next rate case. In Case No. U-21297, the Commission reduced the approved base amount to $10.1 million, assuming the company achieves approximately 52% of its targeted metrics. In this case, DTE Electric states that the projected balance assumes that DTE Electric will not achieve 100% of its target levels in 2023 based on projected performance. The amount below base will be deferred to a regulatory liability. However, the company expects to achieve 100% of its target levels in 2024 and will defer the difference between the actual results and the annual base amount of $10.1 million. 6 Tr 1546.

The company states that if the Commission approves the full EICP proposal, the mechanism is not needed, but if a lesser amount is approved, the company requests the following modifications:

> First, the base amount should be reset equal to the amount of incentive compensation approved for recovery in base rates in this case. Second, the mechanism should apply to the totality of the Company's incentive compensation program including the portion related to financial metrics. [DTE Electric] Witness Fix supports the reasonableness and prudency of the Company's compensation practices, including incentives tied to financial metrics. Third, the deferral should cover the total actual payout, including amounts above 100% of the target.

6 Tr 1547.

The Staff proposes a $39.232 million reduction to the company's incentive compensation O&M expense for expenses tied to financial metrics but finds the inclusion of $20.271 million tied to operational metrics in EICP to be reasonable. 6 Tr 4925; Exhibit S-7.0; *see also*, Staff's initial brief, p. 97. The Staff argues that ratepayers benefit from operational metrics and the company's shareholders benefit from financial metrics. Therefore, per the Staff, it is reasonable for ratepayers to pay for incentive compensation based on operational metrics, but not for financial metrics. The Staff contends that the Commission has previously found that shareholders, not ratepayers, should pay for incentives related to increasing profits and that the company did not justify a deviation from that reasoning in this case. Staff's initial brief, pp. 97-98. The Staff discusses and lists 12 previous rate case decisions, including those of DTE Electric, in which the Commission has excluded financially measured incentive compensation from the revenue requirement. *See*, 6 Tr 4923-4924.

The Staff also addresses the $8.960 million in restricted stock or performance shares that are awarded in the LTIP and are based on DTE Energy's stock prices. 6 Tr 4925; Exhibits S-7.2 and S-7.3. The Staff states that the Commission has repeatedly disallowed compensation related to financial measures and cites to the May 8 order, the November 18 order, and the December 1 order in support. 6 Tr 4926.

The company did not provide rebuttal testimony to Staff's proposed disallowance but responded to the Staff's position in its initial brief. DTE Electric's initial brief, p. 257. The company contends that its EICP proposal is transparent and fully supported and recalls its BCA showing a net customer benefit of $44.974 million. DTE Electric's initial brief, p. 257 (citing 6 Tr 2891-2896; Exhibit A-21, Schedule K6). DTE Electric touts the importance of incentive compensation plans in attracting and retaining a talented workforce and argues that its overall compensation program is comparable to other companies competing for the same employees. DTE Electric's initial brief, pp. 257-258 (citing 6 Tr 2867-2872). DTE Electric emphasizes this point and adds that without its short-term incentive compensation programs, the company's pay would be 10.7% less than the market medians. DTE Electric's initial brief, p. 258 (citing 6 Tr 2874). DTE Electric states that its incentive plans allow the company to provide a lower level of base pay and that without them, the company would have to increase base pay that would in turn increase the cost of employee benefits (i.e., life insurance and the savings plan). DTE Electric's initial brief, p. 258 (citing 6 Tr 2867-2868, 2870). The company claims that its customers benefit from the company having employees with the requisite skills and experience to provide quality service. DTE Electric's initial brief, pp. 258-259 (citing 6 Tr 2868, 2877-2878).

The Attorney General recommends that the Commission allow the portion of EICP pertaining to operational measures but disallow the $39.2 million related to financial measures. Attorney General's initial brief, p. 74. The Attorney General argues that the LTIP, AIP, and REP are heavily skewed toward measures benefiting shareholders and that the benefits touted by the company are "based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved." 6 Tr 3701. The Attorney General contends that the goals of these plans incentivize cash flow and profit and that these measures are not tied to direct customer benefits. Elaborating, she explains that for AIP and REP, customer satisfaction represents only 20% of the total weighting, and that the employee engagement and operating excellence categories have no customer visibility or benefit. The Attorney General argues that the electric outage metrics (SAIDI excluding MEDs) and customer outage metrics are the only categories directly linked to customers but represent a small portion of the expected payout. 6 Tr 3702. As to the LTIP, the Attorney General states that it is heavily weighted on total shareholder return that has nothing to do with creating direct benefits for customers. 6 Tr 3703.

As to the nearly $45 million in net customer benefit claimed by the company, the Attorney General testifies that:

> the largest benefits showing in this exhibit are in the areas of (1) Safety ($9.5 million); (2) Operating Excellence ($58.4 million), with a large part of this category being highly dependent upon a more aggressive tree trimming program and capital spending program, which should in turn reduce the SAIDI outage metric; and (3) $20.4 million of benefits related to Employee Engagement Gallup results, whereby better employee survey results should (according to Gallup) lead to reduced absenteeism, higher productivity, and a better safety record.

6 Tr 3703.

The Attorney General also contends that the company underperformed on its performance metrics for the various EICPs in 2023 and the preceding five years which lends credible doubt to whether the company will achieve its own metric targets in the projected test year and will not pay out the incentives it seeks to include in the revenue requirement. 6 Tr 3704-3705; Exhibit AG-21. Citing the company's calculated percentage of non-financial metrics achieved at target or better over the past five years ending in 2023 of 47.4%, the Attorney General recommended that the Commission allow recovery of 47.4% of the EICP tied to operational metrics. Per the Attorney General, this would be $10.663 million disallowance in addition to the $39.232 million for a total disallowance of $49.895 million. 6 Tr 3706. Citing her testimony on working capital and Exhibits AG-20 and AG-44, the Attorney General noted that the Commission needs to remove $1.358 million of negative amortization expense from excess compensation expense paid in the 2023 projected test year in Case No. U-20836, bringing the total reduction in EICP to $51.253 million. 6 Tr 3706.

In rebuttal to the Attorney General's additional disallowance related to operating measures, DTE Electric argues that the Attorney General's analysis:

> failed to recognize that while certain measures may produce results less than Target, other measures can produce results greater than Target. There are also various gradients of performance between Threshold and Maximum that can produce payouts. Exhibit A-35, Schedule Z1 shows that for the last five years, the actual weighted performance was 79.3% for the AIP, 81.5% for the AIP Executives, and 69.2% for the REP, for a combined average of 76.6%[.]

DTE Electric's initial brief, p. 259; *see also*, 6 Tr 2901-2903. The company contends that the Attorney General's binary approach—a target was met or not—does not recognize that incentive payouts fall within a wide spectrum of performance levels. The company then points to the Commission's rejection of the Attorney General's similar argument asking for a 50% disallowance when the company had shown achievement of performance levels at 96.3% in AIP and 82.8% in REP. DTE Electric's initial brief, pp. 259-260 (relying on May 5, 2019 order in Case No. U-20162, p. 93, and April 18 order, p. 49).

ABATE similarly argues for the exclusion of $39.232 million associated with financial measures and $9.539 million associated with operational measures not achieved by DTE Electric. ABATE's initial brief, p. 44. ABATE supports recovery of incentive compensation reflecting customer-directed goals such as service reliability and employee safety and cites to the Commission's previous orders that have agreed with such an approach. *Id*., pp. 44-45 (citing December 22, 2021 order in Case No. U-20963, pp. 297-298 and May 8 order, pp. 17-19). ABATE contends that, while the company acknowledged its obligation to demonstrate customer benefits for financial metrics, it failed to do so. ABATE points to Exhibit A-21, Schedule K-6 showing the costs of financial metric incentives at $39.232 million and the customer benefits at only $19.946 million. ABATE's initial brief, pp. 45-46.

ABATE also challenges the company's full recovery for operational metrics stating that the benefits do not exceed the expense, pointing to the customer satisfaction metric's expense and safety and engagement expenses which, taken together, exceed their purported benefits by $5.644 million. ABATE also cites DTE Electric's failure to meet its target values in SAIDI (excluding MEDs) in 2023 and contends that the company is not reasonably certain that it will reach its targets in the projected test year. 6 Tr 3345-3346 (relying on Exhibit A-21, Schedule K-6). ABATE argues the company's history of revenue sufficiency justifies disallowance and that customers should not pay for incentive payouts for service that does not meet target performance levels and does not sufficiently benefit customers. ABATE's initial brief, pp. 46-47; *see also*, 6 Tr 3345-3347.

Incorporating its disagreement to the Staff's and Attorney General's disallowances for financial metrics, DTE Electric also disagrees with ABATE's similar disallowance and additional disallowance related to operating measures claimed not to have measurable net customer benefits.

DTE Electric calls ABATE's reasoning flawed because: (1) the BCA presented in Exhibit A-21 shows only quantifiable benefits but does not capture the other customer benefits that cannot be specifically quantified, (2) the Commission has consistently assessed net customer benefits on an aggregate basis, not for each measure, (3) ABATE's assessment of expenses related to SAIDI (excluding MEDs and CEMI4) incorrectly assumes that payouts are based on meeting a target or not, when payouts are based on a range of achievement, and (4) it is unreasonable for ABATE to rely on 2023 target achievements only when the company surpassed the CEMI4 target in 2022. *See*, 6 Tr 2904-2907. DTE Electric also contends that ABATE's assertions about the company's revenue sufficiency lack merit because the company uses a projected test year and therefore, historical revenue is irrelevant. DTE Electric's initial brief, p. 262; *see also*, 2 Tr 186. Lastly, the company states that ABATE has essentially proposed retroactive ratemaking which is illegal. DTE Electric's initial brief, p. 262.

To begin, the Commission finds that DTE Electric's EICP request should be reduced by the amount related to financial performance metrics. The Commission has consistently denied recovery for financial metrics on the basis that they are beneficial to shareholders but do not produce sufficient direct benefits to ratepayers that would justify recovery. *See*, December 22, 2005 order in Case No. U-14347, p. 35; November 19, 2015 order in Case No. U-17735, p. 78; December 11, 2015 order in Case No. U-17767, pp. 76-77; November 18 order, pp. 300-302; December 1 order, p. 238. The Commission finds that DTE Electric has presented nothing new on this record to demonstrate that the nature of its EICP tied to financial metrics has changed or produced different benefits than it has in the past. DTE Electric's evidence shows that the costs of the financial metric incentive payouts outweigh the benefits to ratepayers and the Commission is not persuaded that it is reasonable to instead consider the aggregate benefit and pass these costs onto ratepayers when the benefits are substantially outweighed by the costs for ratepayers alone. *See*, 6 Tr 2891-2896; 3701-3703; 3344, 4264-4265; 4923-4925; Exhibit A-21, Schedule K6. Therefore, the Commission adopts the Staff's, ABATE's, and the Attorney General's recommendation to disallow $39.232 million. *See*, 6 Tr 4263, 4923-4925.

The Commission also finds the Staff's position with respect to restricted stock to be persuasive and supported by the record as well as precedent. In a discovery response and testimony, the company indicates that its LTIP is awarded with restricted stock or performance shares, both of which are based on DTE Energy stock prices and are awarded for achieving financial performance goals. However, DTE Electric explains that while restricted stock is granted under the LTIP, the payouts are not dependent on future company or employee performance and therefore, restricted stock is not an element of incentive compensation. *See*, Exhibit S-7.2; 6 Tr 2890-2891, 4925-4926. The Commission finds that the restricted stock expense should be excluded from the revenue requirement for similar reasons as the incentive compensation tied to financial measures—the benefits are skewed towards shareholders rather than customers and the Commission has routinely disallowed such compensation. *See*, 6 Tr 4925-4926; Exhibit S-7.3; May 8 order, pp. 202-203; November 18 order, pp. 302-303; December 1 order, pp. 238-239. Thus, the $8.960 million in restricted stock is disallowed from the revenue requirement. *See*, Exhibit S-7.3.

Regarding the Attorney General's arguments that $10.663 million of EICP pertaining to operational metrics should be disallowed, the Commission declines to disallow these expenses in this case. While the Attorney General claims that DTE Electric has only achieved 47.4% of its targets over the past five years, the company argues that its combined average achievement of its operational targets over the same timeframe is 76.6%. *See*, 6 Tr 2901-2903, 3700-3705;

Exhibit A-35, Schedule Z1; Exhibits AG-21 and AG-51. The Commission agrees with the company, based on the record in this case, that the Attorney General's binary approach of judging a target as met or not ignores that the company employs an incentive payout system that is based on a gradation of meeting targets with threshold, target, and maximum achievement levels.

Based on record evidence in this case, the Commission is convinced that the framework laid out by the company, which uses a minimum threshold for each operational metric in order to be eligible for incentive compensation, then uses a graduated scale up to the performance target, and finally allows for an incentive to be paid above 100% for performance above the target (up to a specified maximum), is reasonable. Further, while reminding the company that the metrics used must continue to be rooted in measures that are meaningfully tied to core operational performance, and that the levels used for threshold and target must continue to be connected to performance expectations of the company's customers, the Commission finds that in this case, the metrics and performance levels used for operational incentive compensation satisfy these requirements.

However, as also discussed *supra*, the Commission was unable to ascertain exactly how the company was employing its weighted averaging and therefore expects DTE Electric, in its next rate case, to provide a clear and thorough explanation of its weighted average and gradation method used to arrive at its combined average achievement levels. *See*, 6 Tr 2881-2896, 01-2903; Exhibit A-35, Schedule Z1. The Commission will not repeat the reasoning described *supra* but incorporates it here.

Therefore, the Commission finds that the company's EICP O&M expense should be reduced by $39.232 million for expenses tied to financial measures for the 2025 test year. However, the Commission authorizes the company to use deferral treatment for amounts above or below the amount approved in this order for actual incentive compensation expenses related to operating measures. Additionally, the Commission is not persuaded to diverge from preceding decisions to approve the company's request for the deferral to recover the actual payout related to operational metrics achieving above 100% of the set target. *See*, 6 Tr 1547-1548. Similar to the Commission's previous approvals, the instant approval for deferral treatment allows the company to recover the actual incentive payout amount for operational metrics achieved, up to the 100% target. *See*, 6 Tr 1546-1547; November 18 order, pp. 301-302; December 1 order, p. 239. While the Commission requests additional explanation and justification to describe the company's weighted average and gradation method for achievement levels in its next rate case, because the Commission finds the framework for determining operational performance incentives reasonable in the instant case, the approved recovery of $20.271 million tied to operational metrics in this case is based on the company's statement that it achieved a combined average of 76.6% of its metrics. With the approved deferral treatment, should DTE Electric fail to meet or surpass the 76.6% level it has established for itself, the amount associated with the shortfall or excess in achievement up to 100% of the set target would be deferred to a regulatory liability or asset account.

Lastly, the Commission adopts the Staff's recommendation to disallow the $8.960 million in restricted stock. *See*, 6 Tr 2890-2891, 4925-4926.

14. Private Corporate Jet Travel

The Attorney General recommends that the Commission disallow approximately $258,000 in test year O&M expenses associated with private corporate jet travel by DTE Electric, DTE Gas, and DTE Energy executives as well as members of the company's Board of Directors. Per a discovery response to the Attorney General, the company stated that it leases a fractional share of an aircraft for use by executives for business travel and that 16 trips were reported in 2022. *See*, 6 Tr 3697-3698; Exhibit AG-47. The Attorney General contends that the private travel pertains to investor and board of director matters that do not directly benefit customers and should be disallowed. The Attorney General adds that commercial flights are less costly, less impactful on the environment, and align better with the company's stated goal of achieving net zero emissions by 2050. 6 Tr 3698; *see also*, Attorney General's initial brief, pp. 72-73.

DTE Electric did not rebut the Attorney General's testimony or address the issue in its briefing.

The Commission finds the Attorney General's position to be persuasive and agrees that the private jet travel expense should be disallowed. As the Attorney General pointed out, most of the private jet travel pertained to shareholder and investor matters with no explanation as to how the travel resulted in benefits to customers. *See*, Exhibit AG-47, pp. 2-3; *see also*, 6 Tr 3697-3698. Further, the company did not rebut or address the issue in briefing, which constitutes abandonment of the issue. Therefore, the Commission disallows the approximate $258,000 for O&M expenses associated with private corporate jet travel in the projected test year. *See*, 6 Tr 3698; Exhibit AG-47, p. 1.

D. Depreciation and Amortization and Allowance for Funds Used During Construction

DTE Electric initially projected $1,266.2 million of depreciation and amortization expense for the 2025 test year and explains that its projection is based on existing plant balances, plus new capital expenditures and assumed retirements, using a half year convention.

The company states its depreciation expense was calculated using the rates authorized by the Commission in Case No. U-18150. DTE Electric explains that its $210.1 million depreciation and amortization increase from the 2022 normalized expense of $1,056.2 million was due primarily to $254.0 million for capital in-service movement. The increase is also driven by approximately

$47.6 million due to reclassifying $2.1 billion of Monroe generation net plant to a regulatory asset effective December 31, 2024. These increases are partially offset by approximately $65.7 million for plant retirements, and software amortization also decreases by $25.6 million in the projected period, per DTE Electric. 6 Tr 1504; DTE Electric's initial brief, p. 263.

Citing its $29.1 million reductions in capital projections, the company correspondingly adjusted its depreciation and amortization expense to $1,264.8 million. DTE Electric's initial brief, p. 263. In its reply brief, the company cites subsequent adjustments to net plant and states that its revised depreciation and amortization request for the 2025 test year is $1,264.6 million projected expense and $56.0 million in AFUDC. DTE Electric's reply brief, pp. 96-97; Attachment A to DTE Electric's reply brief, p. 3.

Based on its proposed capital expenditure disallowances, the Staff proposes a depreciation and amortization expense of $1,253.406 million. Staff's initial brief, p. 106.

Based on her proposed capital expenditure disallowance, the Attorney General recommends a $40.788 million reduction to the company's proposed expense that it presents in Exhibit A-13, Schedule C6. Attorney General's initial brief, p. 82; Exhibit AG-18.

Consistent with the decisions and adjustments regarding capital expenditures made in this order, the Commission approves a depreciation and amortization expense of $1,245,376,000 and AFUDC of $55,969,000.

E. Property and Other Taxes

DTE Electric seeks to recover $328.8 million in property tax expenses for the 2025 test year explaining that its property tax expense is the amount of property taxes deducted for book purposes whereas the company's property tax liability refers to the amount of property taxes payable to local governments. 6 Tr 2836-2837, 2844; Exhibit A-13, Schedule C1; *see also*, DTE

Electric's initial brief, pp. 263-264. The company states that it calculates this amount by taking 61% of the 2024 calendar year liability, plus the 39% of the 2025 calendar year liability. DTE Electric contends that this two-year allocation methodology has been used for several years and is generally based on the fiscal years of the jurisdictions to which the company pays property taxes. 6 Tr 2836.

Explaining its instant expense request further, the company states:

> The 2024 calendar year property tax expense of $294.9 million (Exhibit A-13, Schedule C7.1, line 13, column (e)) represents 61% of the 2023 property tax liability and 39% of the 2024 property tax liability. Due to the two-year expensing methodology, the increase of $22.3 million over the 2023 property tax expense of $272.6 million was driven by the changes in both the 2023 estimated tax liability and the 2024 projected tax liability.
>
> The 2025 calendar year property tax expense of $328.8 million represents 61% of the 2024 projected property tax liability and 39% of the 2025 projected property tax liability. Due to the two-year expensing methodology, the increase of $33.9 million over the 2024 property tax expense of $294.9 million is driven by the increases in both the 2024 and the 2025 projected tax liabilities.

6 Tr 2836-2837.

The Staff recommends a $693,000 reduction from the company's property tax expense of $328.772 million,[42] resulting in a recovery of $328.080 million. The Staff's reduction is a result of corresponding capital expenditure reductions, supported by the Staff in this case. Staff's initial brief, p. 107; *see also*, Staff's initial brief, Appendices C and E, p. 3.

In rebuttal, the company states that it agrees with the Staff's methodology and states that if the Commission orders capital disallowances, then the Staff's methodology would be reasonable to use when calculating the corresponding adjustment to property tax expense. 6 Tr 2846-2847.

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[42] The Staff uses the more precise figure of $328.772 million for this expense while, above, the company uses an amount rounded up to $328.8 million.

However, in its reply brief, the company emphasizes that the Staff's method should be used only if there are capital disallowances, which the company contends there should not be. DTE Electric's reply brief, p. 97.

The Attorney General recommended a $12.261 million reduction in DTE Electric's property tax expense based on adjustments to the company's proposed capital expenditures. 6 Tr 3708; Exhibit AG-18; *see also*, Attorney General's initial brief, p. 83.

In rebuttal, the company disagrees with the Attorney General's calculation stating that it failed to consider the following aspects of property tax expense calculations: (1) not all capital expenditures are subject to property tax in the same way and the Attorney General's method does not account for those differences, (2) capital expenditures related to steam power generation and nuclear generation were treated as non-taxable in the company's filing, and (3) the Attorney General's method ignored the difference between property tax expense and property tax liability and that liability is expensed over two-years at 39% of the current year and 69% of the subsequent year. 6 Tr 2843-2844. The company contends that the Attorney General's method results in an overstated adjustment.

The Attorney General responds that in follow up discovery, DTE Electric confirmed that it expenses its property tax liability over two years. Attorney General's initial brief, pp. 83-84 (citing Exhibit AG-63). The Attorney General contends that in her property tax calculation she only applied adjustments to capital expenditures prior to 2025 and excluded 2025 capital disallowances in the calculation. Therefore, per the Attorney General, she correctly captures the two-year cumulative expense impacting the projected test year property tax expense and maintains her $12.261 million figure. Attorney General's initial brief, p. 84.

In its reply brief, the company disputes that the follow up discovery referenced by the Attorney General confirms her methodology. Rather, according to DTE Electric, Exhibit AG-63 only discussed how property tax liability is expensed over two years and the Attorney General's method remains flawed. The company avers that if there are capital expenditure disallowances, the Staff's methodology should be used. DTE Electric's reply brief, pp. 97-98.

ABATE includes in its testimony a $6.1 million projected test year property expense. 6 Tr 3361. ABATE did not address the property tax issue in either its initial or reply briefs.

In rebuttal, DTE Electric states that ABATE did not include testimony or briefing explaining its property tax expense, but notes that in ABATE's workpapers, it included a formula showing the proposed tax adjustment was calculated by dividing ABATE's proposed capital expenditures by two and multiplying this by 1.5%. 6 Tr 2844-2845. The company disagrees with ABATE's methodology stating that it "bears no resemblance to how the Company calculated property tax expense in this case[.]" 6 Tr 2845.

The Commission agrees with the company and the Staff's methodology for calculating the property tax expense and finds that it appropriately reflects the application of property taxes to varying capital expenditures and how the company expenses tax liabilities. *See*, 6 Tr 2836-2837, 2843-2844. The Commission further notes DTE Electric's agreement with the Staff's methodology in the event of capital expenditure adjustments. 6 Tr 2846. Consistent with the adjustments to capital expenditures described in this order, the Commission finds the company's recovery of property tax expense for the projected test year should be $327,290,000.

For Other Taxes, DTE Electric projects $53.2 million for the 2025 test year. *See*, 6 Tr 2837; Exhibit A-13, Schedule C7. No party contests the company's projection for Other Taxes. Finding this matter uncontested and the company's position to be supported by the record, the Commission adopts DTE Electric's projected $53.2 million for the test year.

F. Income Tax Expenses

DTE Electric seeks recovery of a total income tax expense of $169.2 million for the projected test year comprised of federal, state, and local income taxes. *See*, 6 Tr 1508-1509, 2828, 2838-2839; Exhibit A-13, Schedules C8, C9, and C10. The Staff recommends adjustments to the company's projection based on adjustments to the company's revenue and expenses, described below.

1. State and Local

DTE Electric projects $58.4 million in Michigan Corporate Income Tax (MCIT) based on a MCIT rate of 5.88%. 6 Tr 1508-1509; Exhibit A-13, Schedule C9; *see also*, DTE Electric's initial brief, p. 264. The company projects a $3.0 million municipal income tax expense, based on a 0.33% composite municipal income tax rate. 6 Tr 2828, 2838-2839; Exhibit A-13, Schedule C10; see also, DTE Electric's initial brief, p. 264. The Staff recommends a state and local income tax expense of $69.557 million. *See*, Staff's initial brief, pp. 107-108. As noted by the Staff, the difference between the parties' state and local income tax calculations is the result of various adjustments to DTE Electric's projected revenue and expenses. State and local income taxes have been calculated based on the decisions in this order and, thus, the Commission approves state and local income tax of $70,400,000.

2. Federal Income Taxes

DTE Electric projects $107.8 million in federal income tax for the test year. 6 Tr 1507-1508, 2838-2839; Exhibit A-13, Schedule C8; *see also*, DTE Electric's initial brief, p. 264. The Staff recommends $133.604 million in a federal income tax expense. *See*, Staff's initial brief, p. 108.

As noted by the Staff, the difference between the parties' federal income tax calculations is the result of various adjustments to DTE Electric's projected revenue and expenses.

The company's federal income tax expense has been recalculated based on the decisions in this order and, thus, the Commission approves federal income tax of $136,282,000.

G. Return on Monroe Regulatory Asset

In its Exhibit A-11, Schedule A1.2, DTE Electric includes an amount of $137.518 million for the return on the Monroe regulatory asset. DTE Electric explains that in the company's IRP case, Case No. U-21193, the Commission approved a settlement agreement, which stipulated that, "[t]he Parties further agree that the remaining [net book value] of Monroe as of December 31, 2024, will be recovered through a regulatory asset with a return on equity (ROE) that will be set at 9.0% amortized over 15 years beginning upon the issuance of an order in the Company's next rate case." 6 Tr 2816 (quoting the July 26, 2023 order in Case No. U-21193 (July 26 order), Exhibit A, p. 4). The company calculates the rate of return to be applied to the Monroe regulatory asset in Exhibit A-14, Schedule D1.

The Staff recommends a return on Monroe regulatory asset revenue requirement of $136.947 million which is $572,000 less than the company's projection. The Staff's reduction is based on its application of a 6.54% projected pre-tax cost of capital rather than DTE Electric's projected pre-tax cost of capital of 6.57% for the Monroe regulatory asset-return on. 6 Tr 4935; Staff's initial brief, pp. 109-110. The Staff explains that both the Staff and the company's pre-tax WACC applied to the Monroe regulatory asset is recalculated from the overall cost of capital using the 9% ROE in accordance with the July 26 order, p. 3. 6 Tr 4935; Staff's initial brief, p. 110 (citing Exhibit A-14, Schedule D1 and Exhibit S-4, Schedule D1). Thus, Staff avers that the return on the Monroe regulatory asset should be recalculated based upon the cost of capital decisions made by the Commission. 6 Tr 4935; Staff's initial brief, p. 110.

The company did not rebut the Staff's position in testimony, but in its reply brief states that the company maintains that the 6.57% pre-tax WACC should be applied to the Monroe regulatory asset resulting in a revenue requirement amount of $137,518,000. DTE Electric's reply brief, p. 71; Attachment A to DTE Electric's reply brief, p. 1.

Consistent with the Commission's decision in this order, the Commission finds that a 6.57% pre-tax WACC should be applied to the Monroe regulatory asset resulting in a revenue requirement of $137,505,000, which is $13,000 less than the company's projection of $137,518,000.

VIII. OTHER REVENUE RELATED ITEMS

A. Infrastructure Recovery Mechanism

DTE Electric proposes to extend and expand the IRM that was approved in the December 1 order. Specifically, DTE Electric seeks to expand the 2025 IRM and extend the IRM through 2026 and 2027 with the following two adjustments:

> 1. Starting in 2026, Pole and Pole Top Maintenance and Modernization (PTMM) would be authorized for IRM treatment (Foley, 2T 118; Elliott Andahazy, 4T 910-11; Exhibit A-33, Schedule X1); and
>
> 2. Starting in 2026, the scope of "4.8 kV Circuit Automation" would be modified to "Distribution Automation." This change reflects the Company's strategy to fully automate the distribution grid to provide safety and reliability benefits to customers (Foley, 2T 118; Hartwick, 4T 634, 642-44).

DTE Electric's initial brief, p. 268. As set forth in the company's Exhibit A-33, Schedule X1 and in testimony, the company proposes the following investment levels for the IRM:

	Previously Approved Investment		Proposed Investment	
Capital Program	2024	2025	2026	2027
Conversions	1.6	185.8	190.0	240.0
Subtransmission Redesign & Rebuild	5.5	53.8	55.0	65.0
Breaker Replacement	13.7	12.6	15.0	15.0
URD Replacement	14.6	13.5	15.0	20.0
Distribution Automation[8]	26.4	24.4	105.0	180.0
Pole & Pole Top Maintenance & Modernization	n/a	n/a	150.0	200.0
Total	61.9	290.1	530.0	720.0

2 Tr 119, Table 1. The company does not propose to change the annual IRM planning process, reconciliation process, or the underlying mechanics of the IRM that were approved in the December 1 order. 2 Tr 119.

Explaining the 2026 and 2027 extensions further, DTE Electric states that while the investment dollar amounts are similar to what was proposed in Case No. U-21297 for 2026 ($530 million in this case and $523.7 million in Case No. U-21297), the proposal here has a greater emphasis on Distribution Automation and PTMM. 2 Tr 120; 4 Tr 634. Per DTE Electric, the company added PTMM because it meets the following screening criteria used to identify capital programs appropriate for IRM treatment: "(1) critical to customer safety, reliability, and/or resiliency, (2) sufficient size and duration, and (3) well-understood scope[.]" DTE Electric's initial brief, p. 269; *see also*, 4 Tr 910-911. For 2027, the company is proposing a total of $720 million in the IRM across the various programs. 2 Tr 193.

The company also testifies to and explains the revenue requirement, the allocation of the revenue requirement to the various voltage classes, and the consistency of the IRM surcharges with overall distribution rate design. *See*, 6 Tr 2613, 2774-2776, 2818-2820; Exhibit A-33, Schedules X4, X6, and X7.

DTE Electric states that approving the extension in this case will avoid starting and stopping the IRM, which it contends "could lead to inefficiencies, and reduce the ability to improve upon the process through stakeholder feedback. The proposed extension is important to ensure that the customer and stakeholder benefits realized through the IRM do not lapse[.]" DTE Electric's initial brief, p. 269; *see also*, 2 Tr 120-122. To illustrate how a gap in the IRM would be problematic, the company explains as follows:

> For example, absent an extension approved in the current case, the Company will not submit an IRM Investment Plan for 2026 (otherwise due no later than August 31, 2025) or hold a stakeholder forum on its 2026 plans since the IRM will not yet have been authorized for 2026.

2 Tr 121.

The company acknowledges the Commission's intention expressed in the December 1 order for DTE Electric to incorporate insights from Case No. U-21400 pertaining to performance-based regulation (PBR) and Case No. U-21305 related to a third-party audit of the company's distribution system. 2 Tr 120-121 (referring to the December 1 order, p. 289). As such, DTE Electric states its intention to propose a PBR mechanism in the first general rate case after the Case No. U-21400 proceeding concludes, which it argues is the appropriate venue to establish a PBR mechanism. 2 Tr 120-125. As to the audit in Case No. U-21305, the company maintains that:

> The Company plans to carefully consider these recommendations and, as determined appropriate by the Company, incorporate them into future Distribution Grid Plans (DGPs) and capital investment plans. Likewise, future IRM proposals

would incorporate the recommendations from the Distribution System Audit where appropriate. For example, while the Company cannot predict what those recommendations will be, it is possible that the Company may propose changes to either the programs or the investment levels authorized for IRM treatment based on Liberty Consulting Group's findings. If a final report is submitted by Liberty Consulting Group in late summer or early fall of 2024, the Company anticipates that there would be sufficient time to incorporate the recommendations from the audit where appropriate into an IRM proposal in the first rate case filed after the current rate case.[[43]]

2 Tr 125-126.

While contending a two-year extension of the IRM is more appropriate, the company adds that a one-year extension would likely allow the pending matters in Case Nos. U-21400 and U-21305 to conclude, although it would leave uncertainty as to the long-term disposition of the IRM. 2 Tr 126.

As to the 2025 expansion, DTE Electric proposes to add to the approximately $290.134 million that was approved in the December 1 order for 2025. *See*, December 1 order, pp. 289-291; 2 Tr 127. The company contends that expanding the 2025 IRM would increase the benefits associated with the IRM. *See*, 2 Tr 127. Specifically, the company states the following areas of capital investment are appropriate for IRM authorization in 2025 beyond what was previously authorized in Case No. U-21297:

- Distribution Automation - $125.6 million of proposed 2025 investment
- PTMM - $121.0 million of proposed 2025 investment
- 4.8 kV Hardening - $125.0 million of proposed 2025 investment
- Frequent Outage Program (CEMI) - $62.5 million of proposed 2025 investment[.]

[43] At the time of the filing of DTE Electric's direct testimony in this case, Liberty Consulting Group, the third-party contractor responsible for performing the audit of DTE Energy's and Consumers Energy Company's (Consumers') respective distribution systems, had not yet filed its final report. The final report for each utility was filed on September 23, 2024 in Case No. U-21305. *See*, Case No. U-21305, filing ##U-21305-0010 through 0013.

2 Tr 128 (footnotes omitted). DTE Electric states that if the Commission were to authorize the above-listed amounts for IRM treatment, in whole or in part, the capital for these programs would be removed from the company's base rate recovery request. 2 Tr 128.

The Staff mostly opposes DTE Electric's proposal to expand and extend the IRM, contending that pausing the IRM is preferable to continuing the IRM inefficiently. Staff's initial brief, p. 161; *see also*, 6 Tr 5236-5237. Specifically, the Staff opposes: (1) extending the IRM into 2026 and 2027; (2) including PTMM for IRM treatment starting in 2026; and (3) for 2025, expanding the distribution automation IRM amount from $24.4 million to $150 million and adding $121 million in PTMM investment, $125 million in 4.8 kV hardening, and $62.5 million in Frequent Outage Program (CEMI) investment to the IRM. 6 Tr 5234-5235. However, the Staff supports the company's proposal to modify the scope of the 4.8 kV circuit automation to distribution automation after the conclusion of IRM plan year two (2025). 6 Tr 5233-5234.

Explaining its opposition, the Staff avers that it is contrary to the Commission's intent expressed in the December 1 order to expand the IRM when the audit report by the Liberty Consulting Group has just been filed and the recommendations therein could result in changes to DTE Electric's plans for the IRM. The Staff similarly contends that it would be inefficient and premature to approve the company's IRM proposal before the Commission issues an order in Case No. U-21400 regarding financial incentives and disincentives. 6 Tr 5235-5236; *see also*, Staff's initial brief, pp. 163-164. The Staff expresses that the company should avoid being locked into specific spending amounts in the proposed IRM programs before the findings of the audit report can be reviewed and potentially impact the IRM in the future. 6 Tr 5235-5236.

The Staff does not share the company's concerns regarding the potential stopping and starting of the IRM and reasons that:

> It is better to pause the IRM for part of 2026 to allow for more efficient spending in 2026 and 2027 than to authorize 2026 and 2027 IRM plans that may have already been rendered outdated by the Liberty audit report in U-21305 and a Commission order in [Commission] Case No. U-21400 on financial incentives and disincentives.

Staff's initial brief, p. 164. Further, the Staff provides the following hypothetical to illustrate the company's stopping and starting of the IRM issue:

> Assume the Company files a rate case next year, on June 2, 2025, with an order issued the following year on April 1, 2026. As part of this order, a revised IRM, incorporating to some degree the Liberty audit findings, is authorized for the remainder of 2026. Since the IRM had expired on December 31, 2025, this reauthorization would bookend a three-month gap from January 1, 2026 – April 1, 2026 where no IRM was in effect. This is how "stopping and restarting" can happen with an IRM.

6 Tr 5236.

The Staff goes on to dismiss the company's stopping and starting concerns:

> Strictly from a process standpoint, a gap can be accommodated. Using the scenario described above, the Company would receive the results of the Liberty audit later in 2024, incorporate findings as appropriate into the partial year 2026 and likely calendar year 2027 IRM Plans, and then include those plans and the IRM authorization requests in the rate case filed on June 2, 2025. Knowing that an order would be issued around April 1, 2026, and assuming that the 2026 IRM Plan Year would start that same day, the Company could send the Partial Year 2026 IRM Investment Plan out to Staff and intervenors on December 1, 2025, and then schedule the forum on or before February 1, 2026.

6 Tr 5236-5237.

In rebuttal, the company disagrees with the Staff's position to allow the IRM to lapse at the end of 2025 but supports the Staff's and the Commission's desire to incorporate the findings from Case Nos. U-21400 and U-21305 into the IRM. 2 Tr 154. DTE Electric disagrees that approving its IRM proposal would lock the company into specific spending amounts and contends that adjustments to 2026 and 2027 IRM authorizations could be made in future rate cases.

> For example, IRM authorization could be granted in this case for 2026 and 2027 at the investment levels proposed by the Company. Then, in a future general rate case (e.g., filed on June 2, 2025 in Staff Witness Evans' example) adjustments to that

> authorization could be made based on the findings of Case No. U-21305 and Case No. U-21400. This updated authorization would become effective at the conclusion of that rate case (e.g., April 1, 2026 in Staff Witness Evans' example). The Company believes such an approach, which would potentially update the amount authorized for IRM treatment mid-year, is preferable to allowing the IRM to lapse at the end of 2025.

2 Tr 154. DTE Electric further disagrees with the Staff's suggestion of filing a partial-year 2026 IRM, arguing that doing so would be inefficient because it would require the company to prepare the IRM plan with a certain level of future IRM authorization and the Staff and interested persons to review the plan. Per DTE Electric, if the Commission authorized a different IRM level from the company's assumed level, DTE Electric would then have to develop a revised plan and conduct another participatory review session which could take several months. 2 Tr 154-155.

In its initial brief, the Staff maintains its position supporting the modification of the 4.8kV circuit automation to distribution automation, opposing the IRM extension into 2026 and 2027, and, for 2025, opposing increases of $150 million for distribution automation, $121 million in PTMM investment, $125 million in 4.8 kV hardening investment, and $62.5 million in Frequent Outage Program (CEMI) investment to the IRM. Staff's initial brief, p. 166.

The Attorney General opposes DTE Electric's IRM proposal. Attorney General's initial brief, pp. 7, 84-90. Relying on the testimonies of witnesses Paul Alvarez and Dennis Stephens (on behalf of the AGMN), the Attorney General opposes an expansion and extension of the IRM into 2026 and 2027, and notes her agreement with the recommendations of MNSC regarding the IRM. *Id*., pp. 84-85.

Following Mr. Alvarez's testimony regarding the critical processes for capital spending governance and the Attorney General's perceived shortcomings in DTE Electric's capital spending governance, the Attorney General discusses the unintended consequences of rider cost recovery mechanisms such as the IRM. 6 Tr 3914-3943. The Attorney General contends that rider cost recovery "shifts capital spending risk from shareholders to customers, shifts prudence responsibilities from utilities to intervenors, and introduces moral hazard into utility distribution grid investment plan development." 6 Tr 3943. The Attorney General explains that once the Commission approves a rider of specific dollar amounts in future years, its ability to disallow recovery of the costs for projects included in that spending essentially ceases and shifts the burden to intervenors to prove imprudence. Additionally, the Attorney General argues the use of riders encourage utilities to propose riskier capital projects because the Commission's ability to disallow recovery diminishes. The Attorney General also points to the increase in DTE Gas Company's (DTE Gas's) main replacement program after the approval of an IRM in Case No. U-21291 as an example. 6 Tr 3944-3946. The Attorney General also contends that the guardrails established by the Commission for the IRM in Case No. U-21297—the IRM plan filing and the participatory review process—are insufficient to prevent the burden to prove imprudence from shifting to intervenors. 6 Tr 3947.

In Mr. Stephens' testimony, the Attorney General addresses the company's 4.8kV conversion, PTMM, subtransmission redesign and rebuild (subtransmission R&R) program, distribution automation program, and breaker and URD replacement and recommends that the Commission reject the 2026 and 2027 IRM for each, describing concerns for each of these program areas. *See*, 6 Tr 3988-3989, 3998-4007, 4008-4025, 4026-4028.

Beginning with the 4.8 kV conversion, the Attorney General questions DTE Electric's planned increased up pace of these conversions, points out the lack of a BCA, challenges the improvements to reliability claimed by the company, and contends that DTE Electric's conversion plan lacks transparency. The Attorney General recommends rejecting the IRM for this program and directing the company to solicit an independent evaluation of the appropriate pace for conversions. 6 Tr 3998-4007.

The Attorney General then discusses the company's PTMM program and her concerns with new poletop inspection and construction standards and the BCA for the program. The Attorney General then states that, "[g]iven the limitations in the PTMM model, and the Company's failure to measure the value and impact of the new poletop construction standards and the PTMM program on which it is based, the Commission should reject DTE's request for PTMM spending in 2026 and 2027 through the IRM." 6 Tr 4015.

Following a description of the subtransmission redesign and rebuild (R&R) program and her concerns with the program, the Attorney General testifies that because of the lack of support DTE Electric provides for subtransmission R&R projects, the Commission should reject the company's request to include this program in the 2026 and 2027 IRM. *See*, 6 Tr 4015-4020. Citing the lack of a BCA and the questionable safety benefits of the distribution automation program, the Attorney General opposes its inclusion in a 2026 and 2027 IRM. *See*, 6 Tr 4021-4025. Lastly, because the Attorney General found the costs to customers to be greater than its delivered benefits, she recommended that the Commission reject the company's proposal to include the breaker and URD replacement program in the IRM extension. *See*, 6 Tr 4026-4028.

In response to the Attorney General, DTE Electric contends that Mr. Alvarez's testimony is largely a repetition of his testimony in Case No. U-21297 and therefore, the company notes its disagreement and points to the company's filings in Case No. U-21297 to show that the IRM is well-supported. DTE Electric's initial brief, p. 271.

MNSC asks the Commission to deny the extension and increases in IRM spending and argues that the company's IRM "slapdash" proposal ignores the Commission's directive in Case

No. U-21297 to incorporate the findings from Case Nos. U-21400 and U-21305. MNSC's initial brief, p. 198. After describing DTE Electric's IRM request totaling approximately $1.7 billion, MNSC states that the company has not identified any projects for the 2026 and 2027 IRM extension or for the additional 2025 IRM beyond the Case No. U-21297 approval. MNSC recounts that, on cross examination, DTE Electric states that if its proposal for the 2025 expansion was approved, it would file an amended plan. MNSC's initial brief, pp. 200-201; 2 Tr 262-263; Exhibit MEC-24. Recalling the company's testimony, MNSC contends that DTE Electric offers little support for the substantial ramp up in IRM spending. MNSC's initial brief, pp. 201-202; 2 Tr 120, 127, 203. Similarly, MNSC argues that the company offers very little support for approving its IRM proposal prior to the conclusions of Case Nos. U-21400 and U-21305. MNSC's initial brief, p. 202.

Turning to its argument that the company prepared its IRM proposal in a haphazard manner, MNSC points to internal communications within the company showing that it initially planned to request an extension only for 2026, but then reversed course without explanation and in just over two weeks had expanded its IRM proposal to that presented in this case. Citing the company's response to discovery, MNSC states that two weeks after the December 1 order, one of the company's options for the IRM was to extend it through 2026 and 2027 at increased spending levels, inclusive of a proposed PBR mechanism. MNSC's initial brief, p. 203; Exhibit MEC-25. MNSC states that the company opted to move forward with only a one-year extension of the IRM but then changed course and chose the 2026 and 2027 IRM expansion option without a PBR proposal. On cross examination, DTE Electric's witness did not know the reason for the change or why the PBR proposal was dropped. 2 Tr 214-215; Exhibit MEC-25.

Citing numerous email exchanges and cross-examination responses, MNSC contends that the spending for the IRM proposal increased by hundreds of millions of dollars over a series of email exchanges and expanded by adding the 2025 additional spending 11 days before the filing of its application in this case. MNSC argues that these emails and responses from the company hastily put together the IRM proposal with enormous spending increases and without explanation indicating any detailed planning. Exhibits MEC-25, MEC-26; 2 Tr 238-239, 246; 3 Tr 599-602. According to MNSC:

> The extension and spending increases are not driven by any reliability justification. Rather, they are targeted to establish the IRM as the "new normal" and "business as usual" – and to grow IRM spending as rapidly as possible to eventually stay out of rate cases. DTE added large amount [sic] of PTMM spending was added [sic] because Company officials believed they had inside information from the auditors about that program. The only apparent governing principles DTE employed as limits on the proposed IRM spending increases were that they not be "too severe" and that they pass the "smell test."

MNSC's initial brief, p. 209 (quotations referring to excerpts from Exhibits MEC-25 and MEC-26). MNSC then recounts the opposition to DTE Electric's IRM proposal by the Staff, the Attorney General, ABATE, and Walmart. MNSC's initial brief, pp. 210-214. In describing DTE Electric's rebuttal to the Staff and responses on cross examination, MNSC point out that, while DTE Electric claimed it would not be locked into spending, DTE Electric admitted that there is no requirement for the company to amend its IRM based on the results of the PBR process and distribution audit. 2 Tr 154, 264-265. MNSC also argues that DTE Electric's claimed concerns about avoiding inefficiencies caused by a gap in the IRM are undermined by the email exchanges described above which show the company's intent to make the IRM the new normal. MNSC's initial brief, p. 211. As to the company's alternative position for a one-year extension, MNSC state that this was the company's initial plan that was abandoned, and the Commission should not accept an alternative proposal presented on rebuttal. *Id*.

Recalling the testimony of Mr. Alvarez, MNSC contends that, contrary to DTE Electric's argument that the Commission rejected this position in Case No. U-21297, the Commission did not accept the company's full IRM proposal but rather limited it. MNSC's initial brief, pp. 212-213. MNSC also recalls DTE Electric's rebuttal to the assertion that the IRM plan and reconciliation process shifts the burden to intervenors to show the IRM plan is unreasonable wherein the company stated the assertion was unfounded. Rather, MNSC argues that DTE Electric's rebuttal is unsupported and that nothing requires the company to act on intervenors' concerns in the plan review process. Lastly, MNSC notes how differently DTE Electric presents the IRM reconciliation process to the Commission versus its internal discussions of it:

> Commenting on a draft presentation about the IRM created by another DTE employee, Mr. Foley wrote: "For cost evaluation, I'm not sure we want to proactively talk too much about [how] the reconciliation process is a time for intervenors to challenge our costs." Once again, DTE seems to be making one set of representations about the IRM to the Commission and parties in this case, while discussing the IRM internally in different terms.

Id., p. 213 (footnote omitted) (quoting Exhibit MEC-26, p. 31).

Similar to its response to the Attorney General, DTE Electric contends that Mr. Alvarez's testimony is largely a repetition of his testimony in Case No. U-21297 and therefore, the company notes its disagreement and points to the company's filings in Case No. U-21297 to show that the IRM is well-supported. DTE Electric's initial brief, p. 271. Responding to MNSC's claims that the IRM proposal was haphazardly developed, the company recalls its testimony asserting that the IRM provides benefits that will grow as the IRM grows. DTE Electric's reply brief, pp. 100-101; 2 Tr 202-204, 249. DTE Electric maintains that the IRM proposal was collaboratively developed among various groups within the company and that the communications cited to by MNSC show that the company considered several opinions, consulted various experts, and spent significant time aligning on a proposal the company believed to be the best option. DTE Electric's reply brief, p. 101. The company claims that its change of course indicates the careful consideration the company employed and its adherence to its belief that greater benefits will result from an expanded and extended IRM. DTE Electric's reply brief, p. 101.

ABATE opposes DTE Electric's IRM proposal citing the prematurity of the company's request in light of the limited approval in Case No. U-21297 to allow for the consideration and incorporation of findings from Case Nos. U-21400 and U-21305. ABATE's initial brief, pp. 50-51; 6 Tr 3380-3382. However, to avoid the company's stopping and starting concern and to reduce the likelihood of DTE Electric filing a rate case in 2025 only to add a year to its IRM, ABATE contends that it may be reasonable for the Commission to allow a third year to the IRM for its existing categories totaling $275 million. *Id*., p. 51.

In response, DTE Electric contends that the infancy of the IRM is not a compelling enough reason to limit the IRM's growth when the investments are warranted. The company adds that approval of the IRM would not preclude the Commission from directing adjustments in future rate cases once Case Nos. U-21400 and U-21305 conclude. 2 Tr 157-158; DTE Electric's initial brief, pp. 270-271. However, in its reply brief, DTE Electric asks that if the Commission rejects its IRM proposal, it should approve a one-year extension at the investment level previously authorized for 2025. DTE Electric's reply brief, p. 99. The company states that this alternative is similar to ABATE's proposal and is more efficient than allowing a lapse of the IRM at the end of 2025. DTE Electric adds that this approach would give the company "clear visibility and certainty of the work it can execute in a specific year well in advance of project execution, so that it can procure the appropriate resources, obtain necessary permits, and otherwise ensure efficient and timely execution." *Id*.; *see also*, 2 Tr 155-156, 158.

Walmart calls for the Commission to deny approval of DTE Electric's IRM proposal. Following a recitation of the company's proposal in this case, Walmart explains that while it appreciates investments in distribution to improve resiliency and reliability, it is concerned that recovery of these investments through mechanisms like an IRM "can expand beyond their original intent and usefulness through a utility's efforts to continuously extend and broaden the scope of such mechanisms[.]" Walmart's initial brief, p. 8; *see also*, 6 Tr 4739-4740. As such, Walmart contends that the IRM proposal should be rejected and the company should be required to recover these additional costs through base rates as is the typical recovery method. Walmart's initial brief, p. 8; *see also*, 6 Tr 4740.

In rebuttal, DTE Electric argues that existing processes already address Walmart's concerns about continuous expansion of recovery mechanisms like the IRM, namely the IRM reconciliation process that addresses the prudency of the previous year's investments. Additionally, the company states that it cannot unilaterally increase the size of the IRM surcharge for 2024 and 2025. 2 Tr 162-163; DTE Electric's initial brief, p. 272.

As an initial matter, the Commission notes that no party contested DTE Electric's proposed methodology for calculating the revenue requirement, surcharge, and allocation of the IRM. Additionally, neither DTE Electric nor the Staff or any intervenors proposed changes to the IRM planning and reconciliation processes. Therefore, the Commission maintains its approval for those elements and limits its review to the issue of expanding and extending the IRM.

Having reviewed the record on this matter, the Commission finds it reasonable for: (1) the 2025 IRM to remain at the levels currently approved by the December 1 order, as suggested by the company as an alternative proposal;[44] (2) DTE Electric to be authorized to extend the IRM through December 31, 2026 with the level of spending capped at the levels currently approved for 2025 and for the programs as approved for 2025,[45] with the exception that spending for conversions shall be removed from the IRM;[46] (3) PTMM to not be included in the IRM; and (4) the IRM not to be extended into 2027 at this time.

Beginning with DTE Electric's arguments regarding a lapse in the IRM, the Commission finds persuasive DTE Electric's argument that the IRM has delivered benefits in terms of certainty in spending on defined distribution programs and increased transparency and outside involvement in the planning and reconciliation process. *See*, 2 Tr 115. While the Staff contends that a lag in the IRM could be accommodated, the hypothetical timing scenario proposed by the Staff is not certain and the Commission finds that allowing an extension of the IRM into 2026 will provide continuity of benefits and efficiency in the planning process. Under the Staff's scenario, the company would propose an IRM plan based on assumptions that may change with a final Commission order, leaving a smaller window of time for the company to make any necessary changes, resubmit its 2026 IRM plan, hold a forum with interested persons, and to incorporate any feedback into its execution of the IRM plan. A one-year extension allows a more favorable timeline to the company, the Staff, and interested persons.

The Commission also finds 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

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[44] *See*, 2 Tr 155.

[45] *See*, 2 Tr 152-157.

[46] *See*, 5 Tr 1206-1207, 1229-1230, 1272-1280; Exhibits MEC-77 and MEC-81.

audit in Case No. U-21305 and the PBR docket in Case No. U-21400 should be incorporated into the next IRM. The Commission is persuaded that results from the extensive audit conducted in Case No. U-21305 should inform not only the company's overall DGP and capital expenditures, but the programs designated for IRM treatment. The Commission found this to be advisable in the December 1 order and the same holds true in this case. *See*, December 1 order, p. 289. The Commission is not inclined to authorize the substantial increases in IRM spending requested by the company without a demonstration that the company has considered and incorporated, where reasonable and appropriate, the findings and recommendations of the distribution audit.

As to the 2026 levels of spending authorized by this order, the Commission declines to authorize the conversion program for IRM treatment in 2026. The company confirms on cross examination that 25 of the 31 circuits identified for conversion in the projected test year (with potential overflow into the proposed IRM years) had neither exceeded their day-to-day rating or were over their distribution design order (DDO). Further for the 2025 test year, in a discovery response, the company states that its most recent area load analysis revealed that 21.8% of load-carrying 4.8 kV circuits will exceed their DDO limit and 7.6% would exceed their day-to-day rating. *See*, 5 Tr 1272-1280; Exhibits MEC-77 and MEC-81. Given that the majority of circuits identified by the company for conversion in the test year and potential IRM years have not exceeded these limits and circuit overloading is a significant factor in the company's prioritization of conversions, the Commission is not persuaded that conversion projects have the level of certainty concerning their necessity to warrant IRM treatment. *See*, 5 Tr 1206-1207, 1229-1230.

Additionally, as the Commission noted above, it is not revising the company's methodology for calculating the IRM revenue requirement or surcharge and it finds that the company's currently proposed methodology is consistent with the approval in the December 1 order. However, given the company's requests to extend the IRM into 2027 and its stated intent to make the IRM a long-term tool of cost recovery, the Commission directs the company to present in its next rate case justification for the rate of return applied to amounts approved for IRM treatment. *See*, 2 Tr 205, Exhibit MEC-26. The Commission agrees that there can be benefits resulting from the use of an IRM. However, the Commission does not intend for the company to use the IRM as a means to achieve a windfall return on IRM assets by having a higher rate of return on IRM than the rate of return that would apply to non-IRM investments in its distribution infrastructure.

To summarize, the Commission authorizes DTE Electric to extend the IRM through December 31, 2026 at the same spending levels that are currently authorized for 2025, with the exception that the conversions program will not be included in the IRM for 2026. The methodology for calculating the IRM revenue requirement, surcharge, and allocation across customer classes is approved as proposed by DTE Electric, as the methodology is consistent with the Commission's approval in the December 1 order. Further, the IRM planning and reconciliation process shall remain the same as the processes approved in the December 1 order. As the Commission explained in the December 1 order, a contested reconciliation proceeding, in addition to the review of the IRM plan, will provide an opportunity for input from interested parties. *See*, December 1 order, pp. 289-290. Further, developing a record in a contested case provides even greater transparency and an opportunity for review of the reasonableness and prudence of the company's expenditures, as well as allowing for input on equity concerns.

DTE Electric shall submit its 2026 IRM plan no later than four months prior to the start of the 2026 IRM year; submit a copy of its plan to all intervening parties in the company's most recently filed general rate case, including the Staff; and schedule and provide a forum, no later than two months prior to the start of the 2026 IRM year, for the Staff and intervening parties to raise any questions or concerns before execution of the IRM plan begins so that DTE Electric may incorporate input from intervening parties into the proposed investments.

B. Storm Restoration and Cost Sharing Mechanism

DTE Electric proposes an SRCSM for its 2025 test year projected storm restoration O&M expenses of $64.5 million, as an alternative to the traditional recovery through base rates.[47] The proposed SRCSM would become effective January 1, 2025, and operate as follows:

> • The calculation of projected storm restoration O&M expenses continues to follow the five-year trailing average methodology as supported by Company Witness Kryscynski in this case; likewise, these projected amounts continue to be authorized for recovery from customers through base rates.
>
> • At the conclusion of each calendar year, actual storm restoration O&M expenses are compared to the amount authorized to be recovered from customers in base rates; for years in which the amount authorized for recovery through base rates changes (e.g., a general rate case order is received and becomes effective mid-year), the authorized recovery amount would be calculated on a prorated basis to reflect the timing and amount of the updated authorization.
>
> • Any difference between actual storm restoration O&M expenses and those authorized for recovery is equally shared between the Company and its customers; specifically:
>
> > o If actual storm restoration O&M expenses are less than projected, the Company returns 50% of the difference to customers by recording that amount as a Regulatory Liability.
> >
> > o If actual storm restoration O&M expenses are more than projected, the Company recovers 50% of the difference from customers by recording that amount as a Regulatory Asset.
>
> • Regulatory Assets and/or Liabilities accumulate between general rate cases until a subsequent general rate case when any net Regulatory Liability or Regulatory Asset is addressed.

2 Tr 132-133.

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[47] As discussed *supra* in Section VII.C.5., the company is projecting $64.5 million in storm restoration O&M expenses. *See*, 2 Tr 129.

To illustrate how the SRCSM would operate, the company provides the following example:

> For example, if the Company's projected costs for 2025 of $64.5[million] were to be fully approved, but actual 2025 storm restoration O&M expenses were only $40.0 million, then the Company would record a Regulatory Liability of $12.3 million to be returned to customers in a subsequent rate case. The $12.3 million is 50% of the difference between approved costs included in base rates (i.e., $64.5 million) and actual costs (i.e., $40.0 million).

2 Tr 133.

DTE Electric contends that the SRCSM is necessary because the current approach of recovering storm restoration costs as an O&M expense does not address the uncertainty and variability of those expenses in any given year. The company explains that storm restoration O&M expenses from 2018 through 2022 ranged from a 17% decrease between 2021 and 2022, to an 85% increase between 2020 and 2021. 2 Tr 130; DTE Electric's initial brief, p. 273. Because trends indicate that extreme weather will continue in Michigan and because the company cannot predict extreme weather in advance, the company asserts that the SRCSM is necessary to address this volatility. 2 Tr 129-132; DTE Electric's initial brief, pp. 273-274.

The company notes that it developed its SRCSM proposal with the Commission's guidance from the March 1, 2024 order in Case No. U-21389 (March 1 order) in mind. DTE Electric explains that in the March 1 order, the Commission rejected Consumers' proposed Symmetric Performance Incentive Mechanism (SPIM), citing concerns that the 10% deadband would not provide sufficient incentives to control costs. Thus, in DTE Electric's instant proposed SRCSM:

> if actual costs are greater than projected, then the Company is incentivized to control costs because it must absorb 50 cents of every incremental dollar that is spent. If actual costs are less than projected, then the Company is incentivized to control costs because it is allowed to retain 50 cents of every incremental dollar that is saved[.]

DTE Electric's initial brief, p. 275; *see also*, 2 Tr 134-136. The company adds that approval of the SRCSM would not preclude the company from acting on future recommendations resulting from the distribution audit in Case No. U-21305. 2 Tr 136.

The Staff does not support approval of the SRCSM because: (1) the Staff supports the full-service restoration expense for the test year recoverable as a traditional O&M expense, (2) the Commission rejected similar mechanisms in Case Nos. U-20963, U-20697, and U-21389, and (3) the Staff would like to use the results from the distribution audit in Case No. U-21305 to inform further cost savings in storm restoration expenses. *See*, 6 Tr 5149. The Staff contends that extreme weather is occurring every year and, as such, customers may never see a benefit from the proposed SRCSM due to the company spending over the requested amount each year. The Staff also argues that the current cost recovery method for storm restoration as an O&M expense provides a stronger cost control incentive in that the company "keeps 100% of savings, rather than 50%, and absorbs 100% of costs overages, rather than 50%." 6 Tr 5149. The Staff recommends that in a future rate case, DTE Electric describe what it defines as a storm restoration expense and how it plans to spend its storm restoration dollars. 6 Tr 5147. The Staff does not dispute the company's projected expense of $64.5 million and recommends full recovery using the traditional O&M expense method.

In rebuttal, DTE Electric argues that the Staff's acceptance of the company's storm restoration expense for the test year does not warrant rejection of the SRCSM. The company repeats its position on the volatility of the storm restoration O&M expenses and argues that the proposed SRCSM will enhance the existing recovery approach. Responding to the Staff's claims that the Commission has rejected similar mechanisms in Case Nos. U-20963, U-20697, and U-21389, DTE Electric distinguishes those cases as follows:

> In all three of those cases, Consumers Energy proposed a *cost tracker*. In this case the Company has proposed a *cost sharing mechanism*, which is fundamentally different. This fundamental difference provides sufficient justification for the Commission to assess the Company's proposal on its own merits and not base its decision on previous orders.

2 Tr 164-165 (emphasis in original).

The company also disagrees that it should await the results of the distribution audit, arguing that any findings from the audit that suggest cost savings could be incorporated into company forecasts in the future but that these activities are unrelated to the SRCSM, which is intended to improve storm restoration cost recovery. The company also disputes the Staff's position that customers may never see a benefit and contend that this would only occur if the actual storm restoration costs were always above the projected level of costs. Lastly, DTE Electric insists that the 50% of sharing of costs that deviate from projections maintains a significant incentive to control these costs. 2 Tr 165.

MNSC opposes DTE Electric's proposal and recall the Commission's rejection of and reasoning regarding Consumers' SPIM in Case No. U-21389. Following a recitation of DTE Electric's proposed SRCSM, MNSC states that the company did not address in its proposal the Commission's concern in Case No. U-21389 about the lack of specified level of performance to be incentivized. MNSC's initial brief, pp. 214-216. MNSC contends that the SRCSM would be more beneficial to the company rather than ratepayers and misaligns incentives when the company's storm performance is already poor. Elaborating on its poor storm performance statement, MNSC explain that:

> [T]he Company's all-weather SAIDI performance has been in the bottom quartile every year between 2017 and 2022, except for 2020. SAIDI Excluding MEDs has been mildly better comparatively, with 2020-2022 in third quartile while 2017-2019 is still in fourth quartile. A similar trend can be seen in the Company's SAIFI performance, where the Company generally ranks in lower quartiles for all-weather SAIFI as opposed to excluding-MED conditions.[ ] For the Company's customers,

> this means that, while their overall reliability performance is rather poor when compared to other utilities, the Company's Storm performance is exceptionally poor in comparison to other utilities.

6 Tr 3770 (footnote omitted). MNSC adds that, for 2023, the company also did not comply with the Commission's annual performance standards for outage restoration in all conditions, gray-sky conditions, and catastrophic conditions. 6 Tr 3770-3771. MNSC also contends that the company's communication regarding restoration times is poor and further proves DTE Electric's underperformance in storm restoration. 6 Tr 3771-3772.

MNSC points out that DTE Electric has projected extreme weather to increase and, therefore, MNSC argues that storm restoration costs are much more likely to exceed projections than to be below them. As such, the company is more likely to recover additional expenses from customers than to refund expenses. 6 Tr 3772; MNSC's initial brief, pp. 216-217. MNSC counters DTE Electric's claims regarding the incentive to control costs, arguing that it would "create a financial incentive for the Company to extend the duration of Storms and perform additional work under the Storm umbrella as it would be 50% cheaper than if performed after Storm-close." 6 Tr 3772. MNSC recalls that the company has stated there is no objective standard, other than the judgment of company field crews, as to when field assets should be replaced versus repaired. Per MNSC, without an objective standard, DTE Electric could alter its storm restoration decision making to its own advantage if the SRCSM is approved. *See*, 6 Tr 3772-3773.

MNSC also argues that the company's ROR sufficiently insulates DTE Electric from the risks it claims from the volatility of storm restoration O&M expenses and assert that the company's ROR on these costs should be reduced. MNSC calls for the rejection of the SRCSM, recommend tying recovery to relevant performance metrics, and ask the Commission to direct the company to develop storm performance criteria including outage restoration, estimate accuracy, resource productivity, and financial responsibility. 6 Tr 3773-3774.

In rebuttal, DTE Electric disagrees with MNSC's claim that the mechanism will skew benefits in favor of the company and, rather, avers that the SRCSM protects the company and customers through the equal sharing of costs that deviate from projections. MNSC's initial brief, pp. 276-277. DTE Electric adds that:

> if the Company consistently spends more on storm restoration O&M than is projected as discussed by [MNSC] Witness Denzler, this will have the impact of raising those projections and the amount recovered from customers in future years under the current approach. If this were to occur, the SRCSM would offer even greater protections than it does today since the amount being recovered through rates would be greater than it is today.

2 Tr 168.

DTE Electric also denies MNSC's suggestion that it would extend its storm restoration. The company argues that storms are defined events with identifiable starts, endings, and impacted customers and only the costs of the storm restoration are considered storm expenses. 2 Tr 168; DTE Electric's initial brief, pp. 277. The company then states that MNSC did not explain how DTE Electric's storm restoration field crews' judgment would enable the company to take advantage of the SRCSM or make it clear how these two things are related. DTE Electric's initial brief, p. 277. The company defends the role and expertise of its field crews and the company's reliance on them for storm restoration work. DTE Electric's initial brief, p. 277. As to MNSC's recommendation for storm performance criteria, the company notes that storm performance is already being addressed in the Service Quality and Reliability Standards for Electric Distribution Systems (SQRS)[48] and in Case No. U-21400 related to PBR. 2 Tr 169. DTE Electric then

[48] Mich Admin Code, R 460.701 *et seq*.

dismisses MNSC's comment regarding the ROR and states that the SRCSM only addresses the storm restoration O&M expense, for which the company does not earn a return. 2 Tr 169.

Ann Arbor opposes the proposed SRCSM recalling the opposition of the Staff and MNSC and the concerns identified in Ann Arbor's testimony. Ann Arbor's initial brief, pp. 21-22. Ann Arbor's first concern with the design of the SRCSM is that it would allow the company "to play a shell game" with capital recovery for repairs and storm restoration work. According to Ann Arbor:

> If the Company "puts off" a repair that could be linked to storm recovery but rolls the truck again two weeks later, does that count against the SRCSM or other accounts? Or if something can be classified as storm recovery that would normally be a standard repair, the Company may be incentivized to do that using overtime during a year where storms are relatively mild. If the need for a restoration is directly attributable to the Company's failure to do proper maintenance on infrastructure, will that receive the same level of scrutiny on revenue requirements in the next rate case if recovered through the SRCSM as it would otherwise?

6 Tr 4260.

Second, Ann Arbor contends that the SRCSM would incentivize the company to over-project storm restoration costs and underspend, allowing the company to keep half of every dollar that it underspent—dollars that otherwise would not be included for rate recovery. 6 Tr 4261. Lastly, Ann Arbor points out that improvements to grid resiliency should result in lower storm restoration costs, but that under the SRCSM, those reduced costs would not flow through to customers and the company would keep half the savings. 6 Tr 4261. Ann Arbor also contends that the company's failure to maintain a proper tree trimming cycle has impacted its storm restoration costs.

Ann Arbor recommends that if the Commission approves the SRCSM, it should reduce the proposed SRCSM each year according to the following formula:

> Step 1: Multiply the total proposed storm recovery costs by 2/3rds [sic] to account for those due to tree damage;
>
> Step 2: Multiply the amount from Step 1 by the percentage of trees in DTE's vegetation plan that were last trimmed 5 or more years ago;

> Step 3: Divide the product from Step 2 by 2 to reflect the amount of reactive maintenance that would have been avoided; and
>
> Step 4: Subtract the result from Step 3 from the proposed SRCSM amount. The resulting difference should be the approved SRCSM amount.

2 Tr 4262-4263.

In rebuttal, DTE Electric argues that Ann Arbor's position reflects a misunderstanding of the company's recovery of storm restoration O&M costs. As to the shell game allegation, the company states that the proposed SRCSM does not impact capital recovery. The company then contends that its projection method for storm restoration O&M expenses is formulaic and based on historical average spending adjusted for inflation, so it could not simply over project and underspend as Ann Arbor suggests. Lastly, addressing Ann Arbor's claim that the company could keep half of the savings resulting from coming up to normal maintenance standards, DTE Electric states that under the current cost recovery approach, the company can keep all the storm restoration O&M expenses if actuals are less than projected spending. DTE Electric maintains that more savings would be passed along to customers under the SRCSM and if the company reduces storm restoration expenses over time, customers will fully capture these savings through lower projected costs that are recovered through rates. *See*, 2 Tr 169-172.

The Commission declines to adopt DTE Electric's proposed SRCSM mechanism for multiple reasons. First, the Commission finds persuasive the Staff's and intervenors' arguments that the proposed SRCSM lessens the incentive for cost-control and that the company's storm restoration performance shows a need for improvement informed by the distribution audit in Case No. U-21305, the SQRS, and the PBR docket in Case No. U-21400. *See*, 6 Tr 3769-3774, 4259-4363.

Second, while there is volatility in storm restoration expenses, the Staff points out, and DTE Electric acknowledges, that the trends of extreme weather are generally increasing, and it is more likely that DTE Electric will overspend. *See*, 2 Tr 129-132; 6 Tr 5149. With the general trend towards more frequent and severe storms, the Commission looks for cost control incentives and improved performance in storm restoration that DTE Electric has not demonstrated. As the Staff states, there is a greater incentive to control costs when the company absorbs 100% of overspending as opposed to only 50% under its proposed SRCSM. *See*, 6 Tr 5149.

Further lending support to rejection of the SRCSM, the Staff observes in testimony that it had difficulty in finding a description from DTE Electric of what the company is spending on storm restoration expenses and what the company defines as a storm restoration expense. 6 Tr 5147. In rebuttal, the company agrees that its testimony could be improved. 6 Tr 3087. The Commission finds this lack of definition and specifics regarding how storm restoration dollars are spent to be surprising given the fundamental and routine nature of this type of expense. Given that the company states on the record that storms are defined events with identifiable beginning and endings, it follows that the company should be able to explain how it defines storm events and the associated restoration work. *See*, 2 Tr 168; DTE Electric's initial brief, pp. 277.

Lastly, MNSC also testifies to the lack of performance metrics tied to the company's proposed SRCSM, namely performance criteria that includes outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to storm scenarios and financial recovery of excess storm restoration costs. The Commission pointed out the lack of performance metrics in Consumers' SPIM proposal in Case No. U-21389 and considers the lack of performance metrics in this case to weigh in favor of rejection as well. March 1 order, p. 175. These concerns are underscored given the evidence provided by MNSC relating to the company's performance on several metrics relating to the company's storm restoration efforts, namely its SAIDI performance (in all-weather and excluding MEDs). 6 Tr 3770. DTE Electric did not rebut MNSC's testimony regarding these performance metrics. The Commission does not find DTE Electric's proposed SRCSM to be appropriate when such a mechanism is more likely to pass half of overspent amounts onto ratepayers when the company's performance has shown areas where improvement is needed.

For these reasons, the Commission rejects DTE Electric's proposed SRCSM in this case.

Noting DTE Electric's and the Staff's support for the amount requested and that no party contested the amount requested, the Commission repeats that it approves the $64.5 million for the projected test for storm restoration as an O&M expense, as discussed *supra* in Part VII.C.5. *See*, Exhibit A-13, Schedule C5.6.

C. Electric Vehicle Pilots – Charging Forward

DTE Electric notes that in the May 2, 2019 order in Case No. U-20162 and the May 8 order, the Commission approved the company's Charging Forward program for electric vehicles (EVs) with some modifications. In addition, the company states that it received "*ex parte* approval of regulatory asset treatment and deferral authority for costs associated with Phase Two of its Charging Forward pilot program" in the March 19, 2021 order in Case No. U-20935. DTE Electric's initial brief, p. 280. Furthermore, the company notes that the Commission addressed disputed issues and approved an expansion of the Charging Forward program in the November 18 and December 1 orders. DTE Electric asserts, "[a]gainst this backdrop, Company witness Bennett provided an update explaining and supporting the costs for various Charging Forward programs and pilots. Total program costs were $6.0 million in 2022, and are projected to be $39.566 million for the 24 months ending December 31, 2024, and $28.480 million for the projected test year."

DTE Electric's initial brief, p. 280 (internal citations omitted). The company also requests transportation electrification plan (TEP) cost recovery and accounting treatment.

The Staff suggests that DTE Electric provide a list of the federal EV programs for which the company has applied and received funds. *See*, 6 Tr 5083-5084. DTE Electric does not object to the Staff's request and states that it "will provide, in the Company's next rate case, a list of the federal EV programs the Company has directly applied for and been awarded." 6 Tr 1993.

The Commission finds the Staff's proposal for DTE Electric to provide in its next general rate case a list of the federal programs for EVs for which the company has applied and received funds to be reasonable and that it should be approved. In addition, the Commission expects the company to provide in its next general rate case a report of the lessons learned for all EV-related pilots to support any future request for conversion from a pilot to a permanent program.

1. Transportation Electrification Plan

DTE Electric explains that in response to the Commission's directives in the November 18 and December 1 orders, the company developed "a comprehensive TEP with robust analyses and careful evaluation of the role of the utility, along with in-depth benchmarking and [interested person] consultation." DTE Electric's initial brief, p. 281 (internal citation omitted). DTE Electric plans to continue providing annual status reports for its TEP programs that track the following metrics:

- Rebate applications filed,
- Rebate applications approved,
- Charger uptime,
- Charger utilization rate,
- On-peak and off-peak charging,
- Customer satisfaction,
- Total investment including equity-focused programs, and
- Installation cost per port, including utility make-ready investment, customer-owed contribution in aid of construction, customer make-ready, and charger costs.

6 Tr 1969.

The Staff contends that TEPs "are informational only and cost recovery is not part of a TEP. Because a TEP is not part of a rate case, this case is not the proper venue to discuss DTE Electric's TEP." Staff's initial brief, p. 13. The Staff asserts that Case No. U-21538 is the repository for TEPs and the docket in which they will be evaluated.

MEIU disagrees with the Staff that TEPs should be evaluated in a docket separate from the utility's rate case. In MEIU's opinion, "there can be a disconnect between what is proposed in a plan (whether distribution grid plan or TEP) and what cost recovery is sought for [sic] in a rate case and that the contested case process better protects [interested persons'] interests and serves to reduce the likelihood that [interested persons'] time and resources are wasted." MEIU's initial brief, p. 35 (citing 6 Tr 4117). In the event the Commission separates the TEP from the utility's general rate case, MEIU suggests conducting the TEP as a contested case similar to the voluntary green pricing cases.

In response to DTE Electric's metrics that it proposes to track in the company's annual status reports for its TEP, MNSC asserts that the Commission should also require DTE Electric to provide 8760-hour annual load profiles. According to MNSC, this will enable interested persons:

> to better understand ways to integrate EV charging onto the grid at times of maximum renewable energy generation. Time-of-use rates and managed charging programs can effectively steer charging to off-peak hours, shifting EV charging loads to low-cost, low-demand times of the day, such as at midnight. For the current grid, that is an effective solution. However, as DTE and other utilities in Michigan increase their renewable energy portfolios, the best time of day is likely to evolve to match periods of high wind or solar generation. Requiring DTE to track and report annual load profiles will help the Commission, DTE, and [interested persons] achieve two of DTE's express goals for the Plan, which include "integrat[ing] EV load with the grid of the future" and "deliver[ing] reliable, cleaner energy to power EVs."

MNSC's initial brief, p. 126 (quoting 6 Tr 1932) (footnote omitted).

DTE Electric objects to MNSC's request that the company provide 8760-hour annual load profiles for EV charging in the EV Annual Status Report. DTE Electric contends that this would be difficult for the company to accomplish "due to challenges in data availability, data cleaning efforts, and potential misunderstanding of the data. For example, the Company simply does not know certain information about public chargers, so the Company cannot commit to the requested granular and specific data." DTE Electric's initial brief, pp. 288-289; *see also*, 6 Tr 2004; DTE Electric's reply brief, p. 106.

MNSC responds to DTE Electric, stating that if:

> there are, indeed, instances where the data is unavailable, then in those limited use cases DTE should not provide the data. MNSC is not asking for the impossible. The other two excuses (data cleaning and misunderstanding) are well within DTE's powers to resolve, either by effectively "cleaning" data before making it public or by clearly communicating the information contained in the data and any useful conclusions that can be drawn from it.

MNSC's initial brief, p. 126.

The Commission agrees with the Staff that Case No. U-21538 is the appropriate forum to analyze and amend DTE Electric's TEP; however, cost recovery associated with the projects and programs in the TEP must continue to occur in a general rate case. The Commission also finds persuasive MNSC's request that DTE Electric provide available 8760-hour annual load profiles for EV charging and directs the company to provide the information in its next EV Annual Status Report.

Next, DTE Electric notes that it conducted an engagement process with interested persons through annual discussions and reports in Case No. U-20162, webinars, and surveys to help shape its TEP. Based on the feedback received from interested persons, the company:

> decided (1) not to waive CIAC beyond revenue credits from existing line extension policy, (2) to use its own EV forecasting methodology to determine charging infrastructure needs, and (3) not to include utility-owned pole-mounted chargers

with this initial TEP. The Company will also continue to engage key [interested persons] during the TEP timeframe by continuing to provide Annual Status Reports for its TEP programs.

DTE Electric's initial brief, p. 284 (footnote and internal citation omitted). According to DTE Electric, the framework to develop its TEP has three primary cost categories for charger installation: UMR, customer make ready, and EV chargers. Furthermore, the company "refined the five primary customer segments (single-family homes, multi-unit dwellings [(MUDs)], public, fleet, and workplace) into more granular sub-segments." DTE Electric's initial brief, p. 284 (internal citation omitted).

DTE Electric states that its:

> proposed TEP rebate programs achieve the Company's guiding principles by facilitating charger deployment while maintaining overall affordability benefits for all DTE Electric customers, improving economics of electrification in the near-term, and promoting equity with a focus on low-income customers and disadvantaged communities. The public (on-route charging) segment makes up the biggest category of investment (30%), partly due to inherently high costs (expensive hardware and high installation costs driven by high-voltage wiring) and partly in response to [interested persons]. [Interested persons] generally indicated high levels of satisfaction with the Company's preview of its TEP programs, but the preview did not include the non-DAC [disadvantaged community]/Rural DCFC [direct current fast charger] customer sub-segment. The greatest impact that [interested person's] feedback had on the final TEP was the inclusion of this subsegment.

DTE Electric's initial brief, pp. 284-285 (internal citations omitted).

MEIU contends that DTE Electric should offer rebates that are easy for customers to claim because it will encourage EV adoption, which provides significant net benefits to ratepayers and society. Specifically, MEIU states that the company should:

> (1) modify its low-income ("LI") single-family home ("SFH") rebates to allow customer eligibility based on geography as well as income, (2) modify the proofs required to prove eligibility for multi-unit dwelling ("MUD") rebates, (3) allow MUD rebates to cover customer make-ready costs, (4) expand eligibility for DCFC rebates beyond the space that is one mile from a throughway, (5) expand funding or program eligibility for public and workplace L2 [Level 2] chargers, and (6) allow

> school bus chargers that are not bi-directional to nonetheless qualify for rebates on a sliding scale.

MEIU's initial brief, pp. 20-21. In addition, MEIU asserts that DTE Electric has no rebate programs for public and workplace Level 2 chargers. MEIU proposes that the company "budget an additional $5 million or draw from the MUD rebate budget to support L2 chargers at long-dwell-time locations such as shopping centers and workplaces." *Id.*, p. 27 (citing 6 Tr 4091-4093); *see also*, MEIU's initial brief, pp. 27-28.

The Commission notes that MEIU's recommendations are addressed in the sections below.

2. Transportation Electrification Plan Portfolio

DTE Electric projects $12.5 million in capital expenditures in 2024, and $5.1 million in 2025 for the Charging Forward program to accommodate the increasing pace of EV sales. *See*, Exhibit A-12, Schedule B5.9; 6 Tr 1998-2001; DTE Electric's initial brief, pp. 282-283; DTE Electric's reply brief, p. 104. As she did with respect to distribution UMR capital expenditures, the Attorney General contends that DTE Electric's forecast for EV adoption is overly optimistic and that the company has not provided the data sufficient to show that these projected amounts will actually be spent. Attorney General's initial brief, pp. 41-42; Attorney General's reply brief, pp. 44-45. The Attorney General proposes a reduction of 45% for both 2024 and 2025, which amounts to a disallowance of $6.98 million for 2024 and $2.29 million for 2025. Attorney General's initial brief, p. 42; 6 Tr 3638.

DTE Electric counters that it has provided "ample evidence to support its EV projections" and that:

> year-to-date EV sales experienced their highest level in Michigan, demonstrating continued growth in the EV market (Exhibit A-49, Schedule NN5). EV registrations through the first five months of 2024 are on track with the Company's projection that over 22,000 new electric vehicles will enter its service area in 2024. The Company's projections therefore reflect the realized pace of EV adoption.

> They are also conservative compared to the Michigan Healthy Climate Plan's target of 50% of new vehicle sales being electric by 2030, as well as MEIU witness Sherman's suggestions.

DTE Electric's initial brief, p. 283.

EVgo disagrees with the Attorney General's claim that "EV adoption [is] currently waning," and argues that "[a]t the national level, a record 1.2 million new EVs were sold in 2023. That trend has continued in 2024—a record-high 330,463 EVs were sold in the second quarter of 2024, representing an 11.3% increase relative to the second quarter of 2023. Growth in non-Tesla EV sales has been exceptionally strong, with 35% year-over-year growth in the second quarter of 2024." 6 Tr 3608; EVgo's initial brief, pp. 24-25 (citing 6 Tr 3318). Therefore, EVgo requests that the Commission approve DTE Electric's EV budget, which includes the company's forecast.

The Attorney General's argument is identical to the argument she made with respect to distribution UMR expenditures, which the Commission has rejected in Part V.B.4.c.ii, above. As the Commission noted above, MEIU finds the company's forecast to be too low, and EVgo and MNSC argue that the Attorney General's forecast is mistaken. As stated above, the Commission finds the company's forecast to be more credible than the forecasts offered by the Attorney General or the intervenors and rejects the Attorney General's proposed disallowances. DTE Electric acknowledges that EV adoption is growing at a slower pace than previously projected, but the company provided evidence that the EV market continues to grow at the rate presented in Michigan. 6 Tr 1999-2000. The Commission finds the company's capital expenditure projections for 2024 and 2025 for the Charging Forward program are reasonable and should be approved.

a. Electric Vehicle Rebate for Choice Customers

According to MNSC, DTE Electric proposes to discount rebates to electric choice customers because they contribute less revenue than full-service customers. MNSC objects, asserting that:

> it is not gross revenue that supports electric vehicle charging programs, but net revenue where the principal cost that must be netted out is the cost of power supply. Net revenue is almost entirely attributable to paying full rates for charging while the utility does not incur corresponding costs for distribution system upgrades. Net revenue from charging at the premises of an Electric Choice customer is likely to be similar to net revenue from charging at the premises of a full-service customer.

6 Tr 3806. The Staff disagrees, stating that "choice customers do not supply revenue associated with power supply rates," and that is "why there is currently no rebate for such customers." Staff's initial brief, p. 147. The Staff asserts that DTE Electric's proposed discounted choice rebate for EV charging should be approved.

The Commission finds the Staff's analysis of this issue persuasive, specifically that "it is not accurate to claim that net revenue is the same between the two groups of customers. It is also worth noting that choice customers are not currently eligible for rebates due to concerns about this issue, and the Company's proposal represents a reasonable proposal to allow for choice customer EV rebates." 6 Tr 4979-4980. Therefore, the Commission respectfully declines to adopt MNSC's position on this issue.

b. Public Chargers

DTE Electric notes that interested persons ranked public charging subsegments most important for utility action because public charging is critical to reducing range anxiety. Accordingly, the company proposes "to support on-route public fast charging by offering a rebate of $70,000 per on-route DCFC in disadvantaged communities and rural areas, and $50,000 per on-route DCFC in other areas. To manage affordability impacts to its customers, the Company proposes to support 35% of the forecasted on-route public charger deployment and rural on-route subsegment, and 35% in the other on-route areas." *Id*., p. 285 (citing 6 Tr 1963). DTE Electric explains that on-route DCFC is defined as fast charging within one mile of a major throughway exit, and that a "major throughway" is "a high-traffic road that is likely to be a limited access interstate or State highway." Exhibit EVG-1, p. 5. To qualify for the on-route Business Charger Rebate program, the company states that "[p]articipating customers will need to install a qualified, networked charger (similar to the Business Charger Rebate program today), authorize the network provider to share charger data with DTE Electric, and commit to 97% charger uptime." 6 Tr 1964 (footnote omitted).

Electrify America objects, expressing concern about DTE Electric's requirement to share charger data to demonstrate the 97% charger uptime requirement. Electrify America states that:

> uptime data is confidential and competitively sensitive data, and . . . while DTE stated that . . . it is not seeking to own and operate EV chargers in its initial TEP, it may seek to do so in the future. As stated by [Electrify America] Witness Davis, companies receiving DCFC rebates from DTE will therefore be required to provide confidential and competitively sensitive uptime data to a potential future competitor.

Electrify America's initial brief, p. 9; *see also*, 6 Tr 4767-4768. In addition, Electrify America asserts that the company has not sufficiently defined the metrics to calculate uptime and, therefore, the task of collecting this data will be onerous and time consuming.

DTE Electric responds to Electrify America, asserting "that charger uptime has to be measured to ensure ratepayer funding is utilized most effectively, and the 97% uptime target appropriately aligns with Federal Highway Administration [(FHA)] requirements." DTE Electric's initial brief, p. 285 (citing 6 Tr 2005-2006); *see also*, DTE Electric's reply brief, pp. 104-105. Moreover, the company notes that the Commission discussed this issue in the November 18 order and adopted a 97% charger uptime consistent with the FHA National Electric Vehicle Infrastructure (NEVI) program guidelines. *See*, November 18 order, p. 331.

In response to Electrify America's claim that DTE Electric's 97% uptime requirement imposes competitive and data collection complications, the Staff asserts that "[t]his concern is reliant on several speculative events, and as such are not outweighed by the benefit of ensuring rebates funded by ratepayers actually go to charger [sic] that are available, rather than wasted on chargers that can't charge." Staff's initial brief, p. 149.

Electrify America, EVgo, and MEIU request that the Commission eliminate the requirement that to qualify for a rebate, a public DCFC must be installed in an on-route location within one mile of a major throughway. *See*, Electrify America's initial brief, p. 12; EVgo's initial brief, p. 9; MEIU's initial brief, p. 25. Rather, Electrify America, EVgo, and MEIU contend that the rebate should be extended to all public DCFC locations, and MEIU requests that the rebate apply to Level 2 chargers in destination locations. *See*, 6 Tr 3300, 4090, 4769; *see also*, Electrify America's initial brief, p. 13; EVgo's initial brief, p. 9; MEIU's initial brief, p. 25.

Electrify America disagrees with DTE Electric's claim that rebates for installation of DCFCs at destination locations are unnecessary because these sites have other "incentives and inherent benefits" to encourage charger installation, which eliminates the need for a rebate. 6 Tr 4769-4770 (quoting Exhibit EVG-1, p. 6). Electrify America contends that the company failed to provide analysis or feedback to support the proposal to eliminate the rebate for charger installation at destination locations. Electrify America asserts that these rebates are crucial, explaining that Electrify America, "like other companies that operate DCFC sites, frequently partners with existing businesses to deploy DCFCs at pre-existing locations of that business. These partnerships are beneficial to both parties, as the relationship de-risks the economics of operating such sites and can lead to more rapid and cost-effective deployment of DCFCs generally." 6 Tr 4770.

EVgo also objects to DTE Electric's proposal to eliminate rebates for DCFCs installed in destination locations, such as retail establishments, restaurants, and grocery stores. In EVgo's opinion, "this significant new limitation could result in the inequitable distribution of chargers in DTE's service territory, especially for multifamily housing residents and others who rely on public charging. [EVgo is] also concerned it could limit program participation." 6 Tr 3290; *see also*, EVgo's initial brief, pp. 13-16; EVgo's reply brief, pp. 1-2. Thus, EVgo requests that the Commission direct DTE Electric to provide rebates for DCFCs installed in both corridor and destination locations. Additionally, EVgo recommends that the company "reallocate any funds remaining from the existing Business Charger Rebate program on December 31, 2024 into the non-DAC/rural subsegment of the proposed Business Charger Rebate program instead of allowing the utility to determine the reallocation of these funds at a later date." 6 Tr 3291; *see also*, EVgo's initial brief, pp. 20-21.

MEIU states that:

> [t]here may be other locations, especially in rural areas, that would serve as appropriate and beneficial locations for a community DCFC. For example, a grocery store on a main road could provide beneficial fast charging but might be excluded from the Company's rebate program if the roadway is not considered a "major throughway" or is not located within on [sic] mile of a road that is considered a "major throughway."

6 Tr 4090; *see also*, MEIU's initial brief, pp. 25-27. The CEOs agree. *See*, CEOs' initial brief, pp. 32-33. MEIU also contends that there should be rebates for public Level 2 chargers that are installed at workplaces and shopping areas because this will assist drivers who do not have charging access at home. MEIU opines that "[b]ecause Level 2 chargers are less expensive than DCFC, utility rebates can incentivize more chargers with less funding." 6 Tr 4092.

MNSC states that DTE Electric's "Business Charger Rebate program for on-route charging directly overlaps with the market segment to be served by the state through its limited NEVI funding, which, for select projects, provides support for up to 80% of the project cost." 6 Tr 3810 (footnote omitted). To connect the Business Charger Rebate program and NEVI funding for charger installation, MNSC recommends that the company's "rebates for on-route charging should be available for 'utility make-ready,' which the Company defines to include 'upgrades on the utility side of the meter, from the line transformer to the meter,' as well as 'customer make-ready,' which includes "upgrades on the customer side of the meter, from after the meter to the EV charger." 6 Tr 3810-3811 (quoting 6 Tr 1953).

In response to MEIU's request to apply rebates to the installation of "destination DCFCs," the Staff asserts that the proposal should be rejected because "it is speculative with no actual examples of the situation described occurring . . . ." 6 Tr 4983-4984; *see also*, Staff's initial brief, p. 151. The Staff contends that if the company's rebate program for installation of on-route DCFCs becomes too restrictive, "there will be plenty of opportunity to rectify the issue prior to it becoming a real problem." 6 Tr 4983-4984. Similarly, in response to MNSC's claim that excluding rebates from the installation of "destination DCFCs" will reduce the number of chargers installed, the Staff explains that the purpose of the rebates is to establish "a skeleton network to reduce range anxiety" and to assist in enabling "the benefit of home charging;" limiting eligibility to on-route chargers achieves this goal. 6 Tr 4982; *see also*, Staff's initial brief, p. 150; Staff's reply brief, pp. 11-12, 35-36.

The Staff also disagrees with MNSC's request to provide rebates for make-ready costs. In the Staff's opinion:

> [i]f rebates were allowed to cover make-ready costs, sites with higher make-ready costs would be made more attractive, adding costs to be covered by non-participating customers through the rebate recovery rather than being borne by the connecting customer. This would extend the responsibility non-participating customer[s] have beyond what occurs under the current program, and the justifications for doing so are insufficient.

Staff's initial brief, p. 148 (citing 6 Tr 4980).

DTE Electric disagrees with Electrify America, EVgo, and MEIU that the rebate should apply to the installation of "destination DCFCs," arguing that the company "is committed to supporting 35% of the forecasted on-route public charger deployment. The funding also aligns with [interested persons]' priorities. The provision of fast, reliable, on-route charging within one mile of a major throughway exit is crucial to increasing customer confidence in EV charging infrastructure." DTE Electric's initial brief, p. 286 (citing 6 Tr 2006-2007); *see also*, DTE Electric's reply brief, p. 105. However, DTE Electric does not object to EVgo's recommendation to reallocate the remaining funding in the Business Charger Rebate program into the non-DAC/rural subsegment of the program, if there is no significant opposition from other interested persons. *See*, 6 Tr 1995-1996; EVgo's initial brief, p. 9.

DTE Electric requests that the Commission decline to approve MEIU's recommendation that the company provide rebates for the installation of public Level 2 chargers. The company states that "[i]t is important to note that the majority of future charging needs are expected to be met by [DCFCs], due to their shorter charging time, and therefore, we reject the recommendation to include rebates for public Level 2 chargers at this time." 6 Tr 2010. In addition, DTE Electric notes that it is less necessary to provide rebates for the installation of Level 2 chargers because installation costs are much less cost prohibitive. The company explains that "[t]hese chargers utilize the standard 240[volt] electrical supply, which many businesses already have in place, making electrification cost effective. Businesses also have additional motivations for installation, such as the potential for increased foot traffic." DTE Electric's initial brief, p. 289 (citing 6 Tr 2010); *see also*, DTE Electric's reply brief, p. 106.

EVgo contends that the Staff does not refute EVgo's arguments set forth in its testimony and initial brief regarding the extension of rebates to the installation of destination chargers. Rather, EVgo states that the Staff "simply assumes corridor charging locations are 'most beneficial to other ratepayers', without citing to any record evidence supporting Staff witness Revere's assumption." EVgo's reply brief, p. 2 (quoting 6 Tr 4983). In EVgo's opinion, the Staff fails to explain why the deployment of community charging should not receive a rebate.

The Commission notes that the 97% charger uptime requirement was addressed in the November 18 order, and in that order, the Commission found that the 97% uptime requirement would be consistent with the proposed, but not yet final, FHA NEVI program guidelines. *See*, November 18 order, p. 331. The Commission finds that the FHA's final rule establishing minimum standards and requirements for projects funded under the NEVI Formula Program was approved and became effective on March 30, 2023, and it requires that NEVI-funded charging stations have an average annual uptime of greater than 97%. *See*, 23 CFR 680.116(b). Thus, the Commission finds that DTE Electric's 97% charger uptime requirement to receive a rebate for installation of public on-route DCFC chargers is reasonable and should be adopted. The Commission notes that if EV charging companies are concerned about the sensitive nature of charging data, EV charging companies may elect to not share data and to not receive the rebate.

The Commission finds that there were no objections to EVgo's request to reallocate the remaining funding in the Business Charger Rebate program into the non-DAC/rural subsegment of the program and, therefore, it should be approved.

The Commission agrees with DTE Electric and the Staff that the Business Charger rebate for the installation of a public charger should apply exclusively to on-route DCFCs, as defined by the company. The Commission finds persuasive the company's proposal that providing fast, reliable, on-route charging within one mile of a major throughway exit will increase customer confidence in EV charging infrastructure. The Staff provides a similarly persuasive argument that rebates for the installation of on-route DCFCs will establish "a skeleton network to reduce range anxiety," which is the purpose of the program. 6 Tr 4982. Therefore, the Commission respectfully declines to adopt EVgo's, Electrify America's, and MEIU's request to extend the Business Charger rebate to the installation of destination DCFCs.

However, the Commission finds persuasive MEIU's recommendation to apply the Business Charger rebate to the installation of public Level 2 chargers at workplaces and shopping areas. The Commission agrees with MEIU that because the installation costs for Level 2 chargers are less expensive, a rebate will likely incentivize the installation of more Level 2 chargers with the added benefit of requiring less rebate funding. The Commission directs DTE Electric to provide a report in its EV Annual Status Report about how the rebates are being allocated.

In addition, for the reasons cited by the Staff, the Commission finds unpersuasive MNSC's request to apply the Business Charger rebate to make-ready costs. The Commission appreciates MNSC's effort to suggest ways to coordinate the Business Charger rebate and NEVI programs and to further extend NEVI funds. However, the Commission agrees with the Staff that if the Business Charger rebate applies to make-ready costs, it will be more attractive to the installing customer to locate the charger at a location in which it is more expensive to install the charger because other customers will bear the increased cost burden through recovery of the rebate, rather than the installing customer, which is the normal procedure. MNSC did not demonstrate that the benefits of extending the rebate to make-ready costs outweigh the increased cost burden to non-participating customers.

c. Residential Customer Charger Rebates

DTE Electric explains that the cost to install a home charger can be significant, thus creating a barrier for many low-income residential customers, and customers need a home charger to obtain the benefit of charging their vehicle for approximately $1/eGallon equivalent. Therefore, the company "proposes Home Charger Rebates for low-income customers in single-family homes over the TEP timeframe at 100% of the forecasted charger deployments in the Company's service territory. The proposed rebate (calculated at an average of $2,200) would cover the cost of the Level 2 charger and the full cost of the customer's installation." DTE Electric's initial brief, p. 286.

At the outset, the company established an income-qualified threshold of 400% of the federal poverty level (FPL) to receive the low-income residential customer rebate for EV charger installation. However, DTE Electric states that "[d]uring the [interested person] engagement phase of the TEP development, the Company received feedback from some [interested persons] that this [threshold] was too high. Consequently, DTE Electric lowered the income eligibility threshold to 200% of the FPL, which also aligns with the threshold for other DTE low-income programs." 6 Tr 2007 (footnote omitted); *see also*, DTE Electric's reply brief, p. 105.

The Staff recommends a $1 million disallowance for the residential customer rebate program. The Staff states that "[t]hese rebates have been part of DTE Electric's efforts since its inception. However, as the Company's EV programs have matured, these rebates make less sense now. Any rebate program needs to be narrowly focused to address a specific EV policy challenge." 6 Tr 5088; *see also*, Staff's initial brief, pp. 12-13. Specifically, the Staff asserts that if the company can successfully address the challenges facing EV adoption and infrastructure implementation for the low-income segment, DTE Electric can request recovery of the $1 million in a subsequent rate case. 6 Tr 5088.

DTE Electric disagrees with the Staff's proposed $1 million disallowance, asserting that "such a funding reduction would result in approximately 455 fewer rebates being available to support EV adoption by low-income single family homes." DTE Electric's initial brief, p. 288 (citing 6 Tr 2003-2004; Exhibit A-49, Schedule NN1); DTE Electric's reply brief, p. 105.

MNSC recommends that the Commission reject the Staff's proposed $1 million disallowance because DTE Electric's "proposal[s] are based on concrete data, detailed forecasts of EV growth in DTE's service territory, the costs of the necessary EV charging infrastructure needed to adequately support that growth, and the overall ratepayer benefits of DTE's Transportation Electrification Plan investments." MNSC's reply brief, p. 34.

In MEIU's opinion, DTE Electric's income eligibility requirements to obtain a rebate for residential charger installation are too restrictive and will not support low-income customer participation. Thus, MEIU suggests that "income eligibility could be raised to 400% of the federal poverty level or that DTE could 'modify its eligibility criteria to allow both an income qualification and a location-based qualification.'" MEIU's initial brief, p. 22 (quoting 6 Tr 4085). Additionally, MEIU contends that customers should be allowed to self-attest to their income. However, MEIU notes that it supports the company's method for identifying disadvantaged communities.

Ann Arbor disagrees with DTE Electric's proposed income eligibility threshold of 200% of the FPL to qualify for the low-income residential customer rebate for EV charger installation. According to Ann Arbor, this threshold is too low and "households at or below that income level are not purchasing EVs." 6 Tr 4272. Instead, Ann Arbor recommends that the threshold be set at 400% of the FPL, or alternatively, 300% of the FPL, at the very least. Ann Arbor contends that "[i]ncreasing the income threshold will make the low-income Home Charger Rebate available to more households (including households for which purchasing an EV is more reasonably attainable), which aligns with the Company's guiding principle of supporting and accelerating EV adoption by facilitating charger deployment." Ann Arbor's initial brief, p. 16.

DTE Electric disagrees with MEIU that customers should be allowed to self-attest their income, asserting that "in its experience administering the EV Rebate program, many customers do not necessarily pay close attention to the eligibility criteria, but instead rely on the Company to validate their eligibility. There is also a risk that individuals could falsely self-attest, taking resources away from those who truly need them." DTE Electric's initial brief, p. 287; *see also*, DTE Electric's reply brief, p. 105.

The Staff opposes Ann Arbor's and MEIU's proposals to set the income threshold to 300% or 400% of the FPL, respectively. The Staff explains that if the income eligibility requirement is set at 400% of the FPL, "households of four persons making nearly or above $100,000 a year" would be eligible and that is not "consistent with the spirit of the income-qualified rebate" because the "median income for a family of 4 in Michigan is approximately $100,000." 6 Tr 4984; *see also*, Staff's initial brief, p. 151; Staff's reply brief, p. 36.

The Commission declines to adopt the Staff's proposed $1 million disallowance. As noted by DTE Electric in Exhibit A-49, Schedule NN5, Michigan EV sales are at their highest level year-to-date, which demonstrates continued growth in the EV market. In addition, DTE Electric avers that "EV registrations through the first five months of 2024 are on track with the Company's projection that over 22,000 new electric vehicles will enter its service area in 2024." DTE Electric's initial brief, p. 283. The Commission finds that scaling back this incentive for EV charger installation will result in "approximately 455 fewer rebates being available to support EV adoption by low-income single family homes." DTE Electric's reply brief, p. 105. However, the Commission agrees with the Staff and finds that if the company requests recovery for additional residential EV charger installation rebates in a future general rate case, DTE Electric must demonstrate that its rebate program is focused on addressing a specific EV policy challenge. *See*, 6 Tr 5088.

Regarding DTE Electric's proposal to set the income eligibility threshold to 200% of the FPL, the Commission agrees with the company that eligibility for the low-income residential customer rebate should align with DTE Electric's other low-income programs. If the company determines that it would be beneficial to deviate from this threshold in a future general rate case, DTE Electric must provide evidence supporting the benefits of the adjustment. Additionally, the Commission directs the company to report in its next EV Annual Status Report or general rate case the number of low-income residential EV charger installation rebates that have been disbursed.

The Commission also declines to adopt MEIU's recommendation that low-income residential customers be permitted to self-attest to their income to be eligible for the low-income residential customer rebate for EV charger installation. The Commission finds persuasive DTE Electric's position that customers may not be acutely knowledgeable about eligibility criteria and, instead, rely on the company to validate their eligibility. And tasking DTE Electric with the determination of eligibility reduces the risk of false self-attestation, which preserves the rebate resources for those who truly need them.

d. Multi-unit Dwellings

DTE Electric explains that to qualify for a Business Charger rebate, a MUD customer must meet at least one of the following criteria:

- MUD is owned and managed by a public entity such as the Housing Commission,
- MUD receives government subsidization that requires at least 40% of the units to be for residents whose household incomes do not exceed 60% of the area median income (such as the LI Housing Tax Credit),
- MUD has at least 40% of their residents participating in the Housing Voucher Program, or
- Other criteria deemed equivalent to those above.

6 Tr 1961.

The company proposes two programs for the MUDs segment. First, the company recommends:

> rebates for qualified low-income MUDs at about 90% of the forecasted MUD charger deployments in this subsegment over the TEP timeframe, for a total investment of approximately $7 million. The proposed income-qualified Business Charger Rebate would cover the cost of the Level 2 charger and the full cost of the installation that the customer is responsible for paying, including the CIAC portion of the utility make-ready and the customer make-ready. The average rebate is calculated at $14,400 per charger.

6 Tr 1959.

Second, DTE Electric proposes offering "support for all other MUDs at about 45% of the forecasted MUD charger deployments in this subsegment over the TEP timeframe, for a total investment of approximately $20.7 million, to cover the cost of the charger and a portion of the installation. The proposed revised Business Charger Rebate would be $5,000 and would cover the cost of the Level 2 charger." 6 Tr 1960.

The company states that to qualify for the income-qualified and non-income-qualified business charger rebate, the MUD would need to demonstrate that it installed a qualified network charger, the network provider is authorized to share charger data with DTE Electric, the network provider is committed to at least 97% charger uptime, and that there is tenant interest in installing an EV charger. To demonstrate tenant interest, DTE Electric explains that the MUD could use one or more of the following:

- tenant surveys,
- signed letters of interest from tenants,
- pre-commitments from tenants,
- documents from past requests for EV charging, or
- data on the number of tenants with EVs.

Exhibit MEIU-21.

MEIU disputes the requirements for a non-low-income MUD owner to obtain a rebate. MEIU contends that "[g]iven the level of costs that a non-LI [low-income] MUD owner is likely to incur to install chargers . . . it is highly likely for that owner to be invested in making them pay off by attracting EV-owning tenants and seeking to encourage EV charging." MEIU's initial brief, pp. 23-24 (citing 6 Tr 4088). Therefore, MEIU requests that the Commission permit the MUD owner to self-attest to tenant interest.

For MUDs that do not meet the company's low-income threshold, MEIU "recommend[s] that the site host should be able to use the full $5,000 to pay for the charger and/or any make-ready costs." 6 Tr 4089.

Regarding self-attestation for the MUD-based charger program, DTE Electric states that "this may be worth considering if there are also other reasonable indications of legitimate charging demand," and cites the examples provided in Exhibit MEIU-21. 6 Tr 2009; *see also*, DTE Electric's reply brief, p. 107.

In response to MEIU's request that MUD owners who do not meet the company's low-income threshold be allowed to use the full $5,000 to pay for the charger and make-ready costs, the company states that "[t]hat is exactly what the DTE Electric TEP is intended to accomplish." 6 Tr 2009.

MEIU continues to assert that MUD owners should be permitted to self-attest regarding tenant interest in a Level 2 charger. However, MEIU states that "[i]f the Commission believes more is required to ensure that non-LI MUD rebates are not misspent . . . it should ensure that the bar is not set unreasonably high so as to increase the transaction costs for MUDs seeking to take advantage of rebates to improve MUD-resident access to on-site EV charging infrastructure." MEIU's initial brief, p. 24.

The Commission approves DTE Electric's income-qualified and non-income-qualified MUD rebate program for EV charger installation. In addition, the Commission finds that self-attestation for eligibility for the MUD rebate program should be approved with DTE Electric's proposed list of options for demonstrating tenant interest.

e. Business and eFleet Chargers

DTE Electric's eFleet and Business Charger programs are part of the Charging Forward Program, which was approved in the December 1 order with $6.9 million for eFleet Business Charger rebates and $11.7 million for Expansion's Business Charger rebates through 2024.[49] The company proposes to continue its eFleet Charger rebate program for school and transit buses by offering a $70,000 rebate per DCFC. In addition, the company states that it will:

> support 100% of the transit bus charger subsegment over the TEP timeframe, and 30% of the forecasted school bus chargers needed while interest and affordability evolve. The Company also proposes to continue offering a $2,500 eFleet Charger Rebate for all fleet owners installing a Level 2 charger (supporting 90% of the forecasted charger deployments in this subsegment), and to continue offering up to a $70,000 eFleet Charger Rebate for DCFCs for approximately 30% of the forecasted charger deployments.

DTE Electric's initial brief, p. 288.

The Staff asserts that "[d]ue to additional requirements from the National Electric Vehicle Infrastructure projects[,] the number of approved and installed DC fast chargers (DCFC) have decreased. Because of this decrease in the rate of installation in these projects and lowered capital costs for the public commercial DCFCs, the total budget for this has been reduced by about $10 million." Staff's initial brief, p. 12; *see also*, 6 Tr 5087. Accordingly, the Staff recommends that the company scale-down its rebate effort and the Staff proposes an $8 million disallowance.

[49] In testimony, DTE Electric states that its eFleet Battery Support is a pilot offering. *See*, 6 Tr 1922. However, the Commission notes that in the December 1 order, the Commission approved the transition of this pilot to a permanent program. *See*, December 1 order, pp. 260-261.

The Staff states that "[b]y moving at a more deliberate speed, DTE Electric would still be able to discover if its revised rebates plans accomplish their intended goals." 6 Tr 5087-5088.

The Staff also recommends that in DTE Electric's next rate case, the company provide detail as to how the School Bus Chargers program is performing and the lessons learned thus far. *See*, 6 Tr 5084; Staff's initial brief, p. 11. DTE Electric responds that it "will make a point of updating the Commission on the status of the School Bus Charger program, in particular, in in [sic] its next EV Annual Status Report." 6 Tr 1993.

DTE Electric objects to the Staff's proposed $8 million disallowance, stating that "the program aims to support various segments, with an increase in proposed 2025 rebate amounts per segment compared to 2024. Such a funding reduction would result in approximately 600 fewer rebates across all segments of the TEP." DTE Electric's initial brief, p. 288 (citing 6 Tr 2003; Exhibit A-49, Schedule NN1); *see also*, DTE Electric's reply brief, p. 105.

MEIU also disagrees with the Staff's proposed $8 million disallowance, arguing that the Staff failed to provide evidence supporting the disallowance. In MEIU's opinion, DTE Electric "has more than demonstrated—again, under unrealistically conservative assumptions—that substantial benefits, including ratepayer benefits, will result from transportation electrification, assuming appropriate investments are made." MEIU's initial brief, p. 31; *see also*, CEOs' reply brief, p. 13.

MNSC asserts that the Commission should reject the Staff's proposed $8 million disallowance because DTE Electric's "proposal[s] are based on concrete data, detailed forecasts of EV growth in DTE's service territory, the costs of the necessary EV charging infrastructure needed to adequately support that growth, and the overall ratepayer benefits of DTE's Transportation Electrification Plan investments." MNSC's reply brief, p. 34 (footnote omitted); *see also*, MNSC's initial brief, p. 121 (citing 6 Tr 1941, 4768-4769). MNSC also recommends that DTE

Electric prioritize applications for rebates from prospective Business Charger rebate program participants that are seeking funding through the state's NEVI program and applications for rebates from prospective school and transit bus participants who are seeking funding through federal programs for zero-emissions buses. *See*, MNSC's initial brief, pp. 127-128.

MEIU contends that to encourage the electrification of fleets, it is important that transit agencies and schools are able to install chargers that facilitate the deployment of EVs. Accordingly, MEIU asserts that "[g]iven that the technology for bi-directional chargers is still improving and costs remain higher for these chargers, [MEIU] would recommend that the Company provide at least partial rebates for schools that are not able to install bi-directional chargers but otherwise meet the rebate program criteria." 6 Tr 4094; *see also*, MEIU's initial brief, p. 29.

EVgo objects to the Staff's proposed $8 million disallowance, stating that the Staff:

> (1) mischaracterizes the scale of DTE's funding request for its Business and eFleet Charger Rebate programs, (2) does not provide evidence for disallowing funding in the Business Charger Rebates program in particular—a program that is both critical and widely popular, (3) does not base [its] recommendation on any analysis of DTE's customers' needs, and (4) does not take into account the ratepayer benefits of these programs.

EVgo's initial brief, p. 22. In addition, EVgo disagrees with MNSC that DTE Electric should prioritize rebate applicants that have secured NEVI funding. EVgo states that while it:

> supports the general goal of coordinating federal, state, and utility programs . . . DTE should aim to support projects that do not qualify for NEVI funding, such as sites in community locations, as these sites may not be developed without utility program support. This approach will serve to fill gaps in the charging network left by the NEVI program and will support the deployment of projects at "community" locations—public chargers in urban and suburban areas away from corridors, where not every home has a driveway, attached garage, or dedicated parking.

EVgo's initial brief, p. 27 (citing 6 Tr 3321).

The CEOs recommend that the Commission reject the Staff's proposed disallowance. The CEOs state that "the Company's analysis [is] well-grounded and supported based on the record. The Company found a net benefit in its proposed spending which Staff . . . do[es] not specifically refute." CEOs' initial brief, p. 32; *see also*, CEOs' reply brief, p. 12.

In response to MEIU's request to offer partial rebates to schools that do not utilize bi-directional chargers, DTE Electric states that it "is open to considering [MEIU]'s recommendation . . . and implement a charger output capacity tier-based rebate approach similar to the existing Charging Forward eFleets Charger Rebates." 6 Tr 2011; *see also*, DTE Electric's reply brief, p. 107.

The Commission finds that DTE Electric provided an abundance of data, detailed forecasts of EV growth in the company's service territory, the expenses for EV charging infrastructure needed to adequately support that growth, and customer benefits of the company's TEP investments, including its eFleet and Business Charger programs. *See*, 6 Tr 1940-1948, 1955-1957, 1965-1967, 1970-1975. In addition, the Commission finds that the Staff did not provide sufficient evidence to refute the company's evidence of EV growth and needed investments for EV charging infrastructure. Therefore, the Commission respectfully declines to adopt the Staff's proposed $8 million disallowance.

The Commission notes that according to the company's testimony and Exhibit A-12, Schedule B5.9, line 22, DTE Electric received approval in the December 1 order for $2 million for the School Bus Charger program and that, as of the company's filing in this case, zero dollars have been disbursed. DTE Electric states that it "has been working to establish the program and intends to deploy the funding in 2024." 6 Tr 1929. The Commission finds that, while it supports the data the company provided to illustrate projected EV growth, as of the date of the filing of this case, no rebates have been issued for this program. Therefore, the Commission expects DTE Electric to inform future forecasts for cost recovery requests with actual program performance data as more information becomes available. In addition, DTE Electric shall provide an update in its next EV Annual Status Report on the status of the School Bus Charger program, how the program is performing, and the lessons learned so far.

In addition, the Commission notes that DTE Electric states that it would consider MEIU's request to offer partial rebates to schools that do not utilize bi-directional chargers. The Commission directs the company to, in its next general rate case, investigate and analyze whether it will be beneficial to offer a charger output capacity tier-based rebate approach for school bus chargers similar to the existing Charging Forward eFleets Charger Rebates.

f. Charging Hubs

DTE Electric states that it spent $1.9 million during the bridge period and projects $3.5 million for the test year for the Charging Hubs pilot. 6 Tr 1928. ITC requests that the Commission approve the company's proposed extension of the Charging Hubs pilot program. *See*, ITC's initial brief, pp. 14-16.

The Staff notes that the Commission approved this project in November 2022, but "it has not progressed at a cadence one might expect. Staff recommends a more detailed explanation for the increasingly slow progress of this project in the next rate case and annual EV report." Staff's initial brief, p. 10 (internal citations omitted).

DTE Electric responds that it will provide a Charging Hubs update in the company's EV Annual Status Report. 6 Tr 1994.

The Commission notes that DTE Electric does not object to the Staff's recommendation. Therefore, the Commission approves the bridge period and test year projections for the Charging

Hubs pilot and directs the company to provide in its next EV Annual Status Report a detailed explanation of the progress of the Charging Hubs pilot project that includes: (1) a description of what has been built and associated costs; (2) a timeline for project completion; (3) a comparison to the original scope, schedule, and budget proposed; and (4) an explanation of any discrepancies. However, as noted above, if at some future date, the company wishes to convert the pilot to a permanent program, the Commission expects the company to provide, in a general rate case, a report of the lessons learned from the Charging Hubs pilot to support any request for conversion.

g. Emerging Technology Fund

DTE Electric states that "[t]he Emerging Technology Fund was approved for $0.9 million in Case No. U-20836, and $1.0 million annually for five years (through year 2028) with Case No. U-21297. Line 21 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b) and $1.8 million in bridge period costs in column (e)." 6 Tr 1930.

The Staff asserts that because the funding for the Emerging Technology Fund comes from the rate case process, DTE Electric should "provide a yearly update about the pilots and what has been learned from them. Staff further recommends that this be provided in future rate case filings (or in the annual EV report if no rate case is filed within a calendar year) until this funding is ended." Staff's initial brief, p. 11.

DTE Electric responds that it "believe[s] the Company is already effectively doing so . . . by committing to providing Annual Status Reports for its TEP programs." 6 Tr 1995.

The Commission finds that there is effectively no dispute between the Staff and DTE Electric on this issue. The Commission directs the company to continue to provide an annual update on Emerging Technology pilots and learnings in its next EV Annual Status Report.

h. Contributions in Aid of Construction

MEIU explains that CIAC are the costs for electric infrastructure upgrades that are necessary to support new load caused by customer interconnection. According to MEIU, the "costs are typically limited to the amount of marginal revenue not expected to be recovered by the new load. In other words, a customer only has to cover costs up to the amount that they will not be contributing over time through the new electricity purchases they will make." 6 Tr 4057. MEIU also notes that:

> many utilities waive CIAC obligations for public EV charging infrastructure because, as discussed further below, the benefits to ratepayers from that public EV charging infrastructure far exceed the revenue generated at an individual charging station site. However, a simple waiver of CIAC obligations does not necessarily cover the full suite of costs that a customer might incur to install new public EV charging infrastructure. For example, as shown in [DTE Electric's] witness Bennett's testimony, for installation of a public on-route direct current fast charger ("DCFC"), the average cost of the utility make-ready infrastructure is $20,630 (including the customer CIAC) and the average cost of the customer make-ready infrastructure is $61,890. This means that a waiver of a customer's CIAC obligations would amount to approximately 15 percent of $20,630, or $3,094.50, whereas a make-ready program could cover those CIAC costs and all or a portion of the customer's (much larger) make-ready infrastructure costs.

6 Tr 4057-4058.

DTE Electric avers that it will not waive CIAC beyond revenue credits from existing line extension policy. The company explains that it:

> maintains its position to align the CIAC policy for EV customers with other connections because this promotes fairness and equity, ensuring all customers contribute to the infrastructure they use, while keeping rates affordable for all customers. The CIAC waiver was initially designed to stimulate interest and growth in EV adoption. Over the five years that the Company has been running the Charging Forward program, the CIAC waiver has played a minimal to non-existent role for the participating site hosts. The need for a CIAC waiver is also further diminishing as the EV market matures and the costs of EV infrastructure are spread across a larger number of users. Therefore, the CIAC waiver is no longer appropriate.

DTE Electric's initial brief, p. 289 (internal citations omitted); *see also*, DTE Electric's reply brief, pp. 106-107.

MEIU objects, asserting that:

> [t]here is great risk that if residential customers are expected to pay CIAC when distribution grid upgrades are needed to accommodate EV charging, there will be significant inequities and that CIAC will become a barrier to EV adoption.
>
> It is very likely, for example, that the first few customers served by a given line transformer can be accommodated without replacing the line transformer but that, at some point, one unfortunate customer's acquisition of an EV will trigger a need to replace the transformer. Under normal CIAC policy, that customer would bear the full cost of the replacement transformer. Customers that subsequently acquire an EV would likely not be required to pay CIAC for a transformer upgrade because it has already been upgraded. This would be manifestly unfair, as the need to replace the transformer to accommodate EV charging would in fact have been "caused" by *all* of the customers that acquired an EV before the transformer upgrade and the transformer upgrade will benefit the customers that subsequently acquire an EV.

6 Tr 4094-4095 (emphasis in original); *see also*, MEIU's initial brief, pp. 32-22. Thus, MEIU requests that the cost of distribution system upgrades for EV charging load be socialized.

MNSC agrees with MEIU that if DTE Electric ends the CIAC waiver, it will cause inequity and delay EV adoption. MNSC explains that "customers who happen to be located in areas where the distribution grid is saturated at the time they want to install an EV charger will be forced to pay for distribution grid upgrades. Customers who are located in areas with surplus distribution capacity, or in an area where a neighbor recently paid to upgrade the grid, will not." MNSC's initial brief, p. 122; *see also*, MNSC's reply brief, p. 38. To avoid these inequities, MNSC states that the Commission should direct DTE Electric to waive CIAC for all new residential and commercial charging infrastructure.

Electrify America disagrees with the company's proposal to eliminate the waiver because "[r]emoving the CIAC waiver undercuts DTE's goals of expanding public charging infrastructure and reducing range anxiety because it increases the already significant costs of DCFC site development and will likely serve to restrict future DCFC site development within its service territory." 6 Tr 4788; *see also*, Electrify America's initial brief, pp. 7-8. Furthermore, Electrify America states that:

> DTE's positioning to potentially own and operate DCFC with ratepayer funds in a future TEP, in conjunction with its proposed removal of the CIAC waiver from its rate book, may lead to reduced deployment in DTE's service area. In turn, this would increase the potential for broader utility-owned and operated infrastructure to fill in the deployment gap, albeit at increased costs to ratepayers when compared to costs of maintaining the CIAC waiver. The Commission should note the competitive implications presented by DTE's proposed removal of the CIAC waiver for EV customers, and maintain the CIAC waiver to reduce the long-term ratepayer contributions required to meet the state's transportation electrification goals.

6 Tr 4788-4789 (footnotes omitted).

The Staff expresses some disagreement with MEIU's and MNSC's recommendations to waive CIAC and to socialize the cost of distribution system upgrades caused by EV charging load. The Staff states that "[i]t is appropriate to waive CIAC requirements within reason, but it is also appropriate to set limits such that customers do not place an undue strain on the system." 6 Tr 5206; *see also*, Staff's initial brief, p. 133. Accordingly, the Staff recommends that all residential customers be permitted one 48-ampere (amp) or lower charger without being charged CIAC. However, if a residential customer selects "any charger greater than 48-amps, or multiple chargers exceeding 48-amps[, it] may trigger incremental CIAC contributions by the customer." 6 Tr 5206.

Regarding a waiver of CIAC for commercial installations of EV charging, the Staff asserts that:

> [w]ith the help of interested parties, similar limits, if any waiver of CIAC is determined to be appropriate for business customers providing (and likely charging) for the service provided by the chargers, could be set for different sizes of

> commercial customers based on voltage level of service, maximum annual demand, or other characteristics that may be deemed important.

6 Tr 5207. The Staff asserts that this waiver should not be extended to DCFCs at commercial locations. *See*, Staff's reply brief, p. 11.

The Commission notes that according to the Staff's "Grid Integration Study Report" filed on June 30, 2023, there is "[a]n emerging concept [of] 'minimum level of service' for a residential electricity customer." Grid Integration Study Report, filing #U-21251-0014, p. 27. The Grid Integration Study Report states that:

> [f]or some customers, taking advantage of even a minimum level of service may require . . . upgrades to the customer's electrical service panel to accommodate increased EV load and other DERs. The appropriate service panel upgrade size would vary between customers. Certain customer service panel sizes are outdated due to high-usage electric appliances becoming more prevalent over time. As customer loads increased throughout the years as new electric appliances became the norm, new-build service panel sizes have evolved to larger sizes. Service panel upgrades are the responsibility of the customer and can be a significant cost.

Id. The Grid Integration Study Report asserts that commensurate upgrades on the utility side of the meter may also be required.

In light of the "minimum level of service" concept, the Grid Integration Study Report notes that Consumers' residential rate schedule was recently amended. Consumers' Tariff D-14.00 states in relevant part:

> Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp [horsepower] or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

> Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.
>
> Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.
>
> This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.
>
> Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Accordingly, to ensure equitable access to a "minimum level of electric service," EV charging infrastructure, and DERs, the Commission finds persuasive the Staff's recommendation to implement a one-time CIAC waiver for new residential customer load, which would also include new installation of EV charging equipment that complies with specific voltage requirements. However, the Commission finds that there is insufficient information on the record to draft an appropriate tariff. Therefore, the Commission directs DTE Electric to propose in its next general rate case, in consultation with the Staff and other interested parties, tariff language to modify its current Tariff C-27.00 to include a limited CIAC waiver, using Consumers' Tariff D-14.00 as guidance.

The Commission agrees with the Staff that it would be beneficial for interested persons to discuss limits for commercial EV charging CIAC waivers. Therefore, the Commission recommends that the Staff convene interested persons to determine the next steps for Level 1 and

Level 2 commercial EV charging CIAC waivers. However, the Commission agrees with the Staff that the waiver should not be extended to DCFCs at commercial locations. Additionally, pending submission and approval of the specific CIAC waivers discussed above, the Commission finds it is appropriate to grant DTE Electric's request to remove the current general CIAC waiver for EV programs by deleting Section C6.1(16) of its rate book for the reasons discussed previously in this section.

3. Benefit/Cost Analysis

DTE Electric asserts that the TEP portfolio-level BCA has a net present value (NPV) revenue requirement of $56 million. The company notes that fleet electrification programs will have a positive NPV of $5 million for "Fleet-Other DCFC" and $37 million for "Fleet-Other Level 2," however there is a negative NPV of $17 million for "Supporting Functions." 6 Tr 1974. DTE Electric explains that "the annual revenue requirement initially applies rate pressure, but the TEP begins providing rate relief in 2033, increasing to a maximum in 2064, so the proposed rebates are beneficial to customers in the long run." DTE Electric's initial brief, p. 290 (internal citation omitted).

The company contends that the following elements add increased costs: (1) utility-owned UMR investment for rebated chargers, (2) rebates for chargers, (3) supporting function costs (for portfolio-level BCA only), and (4) energy costs of serving "qualified" additional EV load. *See*, 6 Tr 1970. DTE Electric asserts that electric revenue from "qualified" additional EV load provides rate relief. In addition, the company states that:

> [f]or additional conservatism, the BCA assumes a constant utilization rate, despite the utilization rate likely increasing over time, especially in segments where chargers serve multiple vehicles, such as on-route DCFCs. For most segments, the utilization rate used in the BCA is the average across the four TEP program years as output from the segment assessment model, discussed above. For a few other segments, utilization rates were chosen using Charging Forward data instead.

6 Tr 1971-1972.

Furthermore, DTE Electric argues that the $56 million in rate relief is conservative because:

> 1. The BCA only considers incremental load from rebated chargers; it does not take credit for any "network effects" of EV sales influenced by the TEP through reduced range anxiety. In fact, as mentioned above, the "qualified" additional EV load accounted for in the BCA is only about 10% of total expected EV load through 2030,
>
> 2. As described previously, utilization rates are held constant over the life of the electrical infrastructure serving the charger, despite likely increasing over time as EV adoption grows, and
>
> 3. The BCA does not take credit for any revenue generated in the first year of any rebated charger's installation, despite rebated chargers coming online throughout the year that the investment occurs.

6 Tr 1975-1976.

In response to DTE Electric's table on 6 Tr 1974 stating that "Fleet-Other DCFC" will have a positive NPV of $5 million and "Fleet-Other Level 2" will have a positive NPV of $37 million, the Staff states that "a positive NPV to the benefit of other customers is achievable, but only if the amount of supporting costs associated with the two programs is low enough and the projects selected for participation are appropriate." Staff's initial brief, p. 135 (internal citation omitted). The Staff contends that the company should conduct a BCA "on each potential project to ensure that the expected benefits to the ratepayers supporting the program through rates from the increased grid utilization outweigh the costs of any rebates or increased system costs creating upward pressure on rates." 6 Tr 4960. The Staff asserts that it is unclear whether DTE Electric is following the process used by other utilities to analyze fleet electrification and argues that it would be appropriate for the BCA. Furthermore, the Staff states that for the residential rebate programs, the benefits and costs should be viewed as a whole, rather than at an individual customer level, to ensure that the benefits to ratepayers who support the programs are realized.

However, the Staff asserts that for fleets:

> the customers are likely large enough to impose substantial costs, particularly with the inclusion of DCFC chargers that may only be used by the participating customer. As DCFC chargers are a large, potentially intermittent load, it is entirely possible they will cause substantial costs that could be borne by other customers. Just like with the Company's other EV programs, it is important that the benefits enabled by the inclusion of a DCFC offset those costs. However, as any given DCFC only enables the benefits from a particular customer in fleet segment, as opposed to all customers in the on-route segment, it is important to conduct the analysis at the same individual customer-level.

6 Tr 4961.

MEIU notes that several states require utilities' TEPs to minimize costs and maximize benefits to ratepayers. According to MEIU, in the BCAs required by these state commissions, the utility must provide a forecast of different EV deployment scenarios and expected benefits from revenue from charging, state and federal incentives, CIAC, estimates of the number of chargers required to encourage EV adoption, charger utilization rates, increases in load, and societal benefits. *See*, 6 Tr 4059-4061.

Next, MEIU contends that there are several issues with DTE Electric's BCA. First, MEIU asserts that the company's forecast of EV adoption is too low. According to MEIU, DTE Electric's forecast does "not correspond to the number of EVs that would need to comprise annual light-duty vehicle sales by 2032 if the U.S. Environmental Protection Agency's ([U.S. EPA]) vehicle emission standards are to be met by that date." MEIU's initial brief, p. 4 (citing 6 Tr 4062).

Second, MEIU contends that DTE Electric's BCA only considers incremental load from rebated chargers and fails to fully recognize the revenue from EV charging. MEIU states that "[b]y accounting for only 10% of the anticipated revenue from EV adoption, the Company is, by necessary implication, ignoring the other 90% of revenue that is indirectly *enabled* by EV charging infrastructure investment, even if it is not directly derivable from a rebated charger." *Id*., p. 6 (citing 6 Tr 4067) (emphasis in original). In other words, MEIU avers, by discounting this revenue, DTE Electric "is essentially undermining the whole theory underlying utility investment in charging infrastructure, which is to help overcome hurdles to EV adoption by ensuring the availability of charging infrastructure." *Id*., pp. 6-7. MEIU requests that the Commission direct DTE Electric to account for the "network effects" of its EV programs as benefits in the company's future BCA. *Id*., p. 9.

Third, MEIU objects to the constant utilization rate in DTE Electric's BCA. In MEIU's opinion, "this assumption is only reasonable for certain types of chargers (e.g., home chargers). But for public chargers, [MEIU's witness] showed that '[i]n 2016, there were seven EVs to each public charging port in the United States,' and that '[b]y 2023, given growth in EV adoption, there were more than 20 EVs per public charging port.'" *Id*. (quoting 6 Tr 4069-4070). MEIU states that the increased utilization rates occurred simultaneously with greater availability of public charging ports, which highlights the unreasonableness of the company's projection.

Finally, MEIU asserts that DTE Electric's BCA is limited in scope and fails to consider "certain societal benefits, including 'reduced greenhouse gas [(GHG)] emissions, reduced criteria pollutant emissions, reduced noise pollution, reduced transportation fuel costs, improved physical and mental health, job creation, and economic impacts.'" *Id*., pp. 12-13 (quoting 6 Tr 4070). Thus, MEIU recommends that the Commission require DTE Electric to include societal benefits, such as GHG and criteria pollutant emissions reductions, through the use of multiple cost tests.

Similar to MEIU, MNSC requests that the Commission approve DTE Electric's TEP but reject the company's BCA methodology. MNSC contends that DTE Electric's BCA method is overly conservative and fails to account for the many benefits of the program. *See*, MNSC's initial brief, p. 124. In addition, MNSC notes that:

> DTE attempts to attribute only a portion of electric vehicle adoption to its TEP, which [MNSC does] not believe is appropriate for a ratepayer impact analysis. Instead, DTE should assess marginal revenues from EVs on a service territory and system-wide basis. This [is] the most natural basis for assessing ratepayer impact and the most reasonable approach from a policy perspective because the total number of EVs and associated net revenue from EV charging can be reasonably calculated. This approach is also justified by analogy to line extensions, where current allowances for line extension recognize that a new customer provides revenue that will fund at least a portion of the capital expenditures that are incurred for line extension, without discounting that incremental revenue by excluding line extensions that would occur anyway without the utility allowance.

6 Tr 3815. The CEOs agree. *See*, CEOs' initial brief, pp. 32-33.

Moreover, MNSC states that including net revenues from charging as a benefit in the BCA is inappropriate because it amounts to a transfer payment between parties and, therefore, DTE Electric's BCA is essentially a "rate-payer impact analysis." 6 Tr 3812. In MNSC's opinion, a thorough BCA for a TEP would:

> include the cost of the electric vehicle set against the avoided cost of the non-electric vehicle alternative, the utility's incremental cost of producing and distributing electricity for vehicle charging, the avoided cost of avoided fossil fuels, the change in maintenance costs of an electric vehicle versus the avoided maintenance of a traditional vehicle, the climate costs of supplying power for electric vehicle charging offset by the avoided climate costs of fossil fuel for a traditional vehicle, the health costs of electricity supply for electric vehicle charging offset by the avoided health costs of avoided transportation fuel production and combustion, avoided economic and national security risks and readiness costs due to reduced dependence on volatile international oil markets, and any other cognizable costs and benefits.

6 Tr 3813-3814.

The Staff disagrees with MNSC that the full value of gross margin from incremental load is applied to offset connections under line extension policies. According to the Staff:

> [l]ine extension policies generally only apply two to three years' worth of expected revenue, sometimes offset by incremental powers [sic] supply costs, as an offset to

> line extension costs, including DTE's. Additionally, costs not covered by the customer installing a charger are necessarily borne by other customers and should therefore be considered a cost when determining net benefits of the program. For these reasons, any arguments relying on this claim, including that "DTE should assess marginal revenues from EVs on a service territory and system-wide basis" as "[t]his [sic] the most natural basis for assessing ratepayer impact and the most reasonable approach" should be rejected.

Staff's initial brief, pp. 142-143 (quoting 6 Tr 3815). The Staff also objects to MNSC's claim that grid upgrade costs associated with connecting EV chargers should be socialized. In the Staff's opinion, MNSC's proposal causes EV owners' costs to be subsidized by other ratepayers, which is contrary to the goal of these ratepayer-funded programs, which is to maximize the net benefit to all ratepayers. Furthermore, the Staff asserts that MNSC failed to consider that socializing the grid upgrade costs would create an additional cost for the program that would need to be included in the BCA.

The Staff also disagrees with MNSC that DTE Electric's BCA is not a true BCA. The Staff states that:

> [e]ach type of [BCA], or perspective from which they are conducted, has value in the Commission's consideration of the programs they are examining. The UCT [utility cost test] shows the impact to ratepayers and the utility, which is important for informing whether or not utility rates are the appropriate way to fund a program (along with other considerations discussed later). The PCT [participant cost test], in spite of MNSC witness Jester's dismissal of its necessity, is useful in determining whether the program will be attractive to participants. The SCT [societal cost test] is useful in determining if there are societal benefits or costs that are not included in the others, providing a more holistic view of the overall [BCA], but not the only perspective that should matter to the Commission. In fact, using a [BCA] that includes societal benefits or costs (such as the SCT) as the sole determining factor of whether or not a given program should be funded by ratepayers would be inappropriate, as it may be more appropriate to fund those programs through governmental (or societal) funding, as that is where the benefits accrue.

6 Tr 4977 (footnote omitted).

The Staff disagrees with MNSC's claim that, rather than attributing EV revenues to EV programs, all EV charging revenues should be considered in the context of a BCA for those programs. The Staff asserts that:

> the appropriate costs and benefits to consider in a [BCA] for a ratepayer-funded program are those to ratepayers. Ascribing benefits to usage that would have occurred absent the program is inappropriate. Therefore, the Company's adjustment to remove a reasonable estimate of the revenue from EV charging that would have occurred absent the program is appropriate, and MNSC witness Jester's claim and related requested relief should be denied. MEIU witness Sherman makes a similar claim that should be denied for the same reasons.

6 Tr 4976 (footnote omitted).

DTE Electric asserts that it adequately supported its BCA and provided detailed responses to MEIU's and MNSC's requested changes. Specifically, in response to MEIU's claim that according to U.S. EPA projections, the company's EV sales forecast is too low, DTE Electric contends that although the U.S. EPA is a credible source, the company relied on multiple sources to create its forecast. Regarding MEIU's contention that DTE Electric's BCA is overly conservative, the company contends that its BCA "ensur[es] that even if the actual benefits are lower than expected, the investment will still be justified." 6 Tr 2013; *see also*, DTE Electric's initial brief, pp. 290-292; DTE Electric's reply brief, p. 108. In response to MEIU's concern that it is unreasonable to apply a constant utilization rate to public DCFC or Level 2 chargers, DTE Electric states that "it is crucial to take a balanced and sustainable approach to expanding public charging infrastructure. This involves taking into consideration technological advancements such as faster charging times that reduce the need for a high number of public charging stations, and user behavior such as EV owners' preference to charge their vehicles at home overnight." 6 Tr 2014. Finally, the company objects to MEIU's request to add societal benefits such as GHG and criteria pollutant emission reductions because these benefits are uncertain, difficult to attribute, and may lead to inequitable results.

In response to the Staff, DTE Electric states that "[i]t is important to consider the portfolio-level benefits that extend beyond the individual customer or fleet segment. Conducting individual BCAs for each fleet customer could also be burdensome and costly, with customers ultimately bearing those costs." DTE Electric's initial brief, p. 291 (internal citations omitted); *see also*, DTE Electric's reply brief, p. 108.

Responding to MEIU, the Staff contends that while it:

> agrees that an SCT or other cost test incorporating societal costs and benefits can provide important information to the Commission, and appreciates the more nuanced discussion MEIU witness Sherman provides regarding appropriate use of the various cost tests previously discussed, as discussed above in response to MNSC witness Jester, such a cost test is not appropriate to use to determine the amount to which such programs should be funded by utility customers regardless of the societal benefits they may produce as discussed throughout this rebuttal, as well as that of Staff witness Krause.

6 Tr 4978. In addition, regarding MEIU's request that the company's TEP include a robust BCA, the Staff states that:

> state and federal incentives are external to the utility cost test because they come from outside the utility. [Staff's w]itness Krause continued, however, that when you switch to the societal cost test (SCT), state and federal incentives become costs because they are paid for by society. Staff recommends that state and federal incentives be treated as benefits in the context of a utility cost test but be treated as costs in an SCT.

Staff's initial brief, p. 134 (internal citations omitted).

ABATE also objects to MEIU's request to include societal benefits in DTE Electric's BCA. In ABATE's opinion, "[t]he proper place for evaluating the SCT and societal benefits related to the TEP is therefore in [interested person] meetings, rather than this contested case." ABATE's initial brief, p. 54; *see also*, ABATE's reply brief, pp. 25-26.

In response to DTE Electric's claim that the U.S. EPA is only one forecaster of many, MEIU states that the U.S. "EPA forecasts are not, however, merely market projections but rather represent realistic ways that vehicle manufacturers might be expected to meet emissions standards." MEIU's initial brief, pp. 4-5. MEIU asserts that DTE Electric fails to explain whether the forecasts used by the company account for reduced vehicle emissions requirements.

Regarding the Staff's recommendation to continue to remove a reasonable estimate of the revenue from EV charging that would have occurred absent the program, MEIU contends that this concept is not accurate. MEIU explains that public EV charging stations directly enable customers to purchase EVs, which results in significant at-home charging and resulting revenue. MEIU asserts that the Staff's approach "assumes that the charging revenues that can be attributed to the Company's programs are coextensive with the charging revenues that are directly derived from rebated chargers. As [MEIU] demonstrates, however, this is unlikely to be the case, particularly given the relative proportions of charging revenue that the Company anticipates receiving from at-home charging vs. public charging." *Id*., p. 7 (citing 6 Tr 4065-4069).

In response to DTE Electric's claim that considering societal benefits such as GHG and criteria pollutant emissions reductions is challenging and inequitable, MEIU argues that numerous utilities have quantified these benefits and federal agencies have used this approach since the 1990s. MEIU states that "[d]oing so is therefore far from unprecedented, and DTE is hardly without guidance as to how best to do so, including from the TEPs against which DTE benchmarked its own." *Id*., p. 13.

MEIU also disagrees with the Staff's interpretation of the SCT. MEIU asserts that:

> [t]he argument is not that EV charging is simply some kind of necessary drain on utility and ratepayer resources, made necessary and desirable only for broad societal benefits it provides. Rather, as DTE itself has demonstrated, even under *unreasonably conservative* assumptions, the integration and growth of EV charging

> will provide net *financial* benefits, in that EV charging customers will contribute more in revenue than the marginal costs required to serve them.

Id., pp. 14-15 (footnotes omitted) (emphasis in original).

MEIU agrees with DTE Electric that the expense of conducting customer-specific BCAs for each potential "Fleet – Other DCFCs" and "Fleet – Other Level 2" project will reduce or eliminate the savings produced by the program. In addition, MEIU agrees with DTE Electric that "blinkered, individualized BCAs would likely be unable to be appropriately and accurately conducted, given the likely externalities of any individual project . . . ." MEIU's initial brief, p. 19.

MNSC recommends that the Commission reject the Staff's request that DTE Electric be required to conduct site-specific BCAs for individual fleet customers and only offer rebates when it is net positive for other customers. MNSC contends that "[t]hat kind of customer-specific benefit-cost analysis is unwarranted and inconsistent with the Commission's prior orders," and cites the November 22 order as guidance. MNSC's initial brief, p. 125.

The Staff disagrees with MEIU that site-specific BCAs should not be conducted. According to the Staff, MEIU's claim is unsupported and should be rejected. *See*, Staff's reply brief, p. 35.

In the July 27, 2022 order in Case No. U-20898 (July 27 order), the Commission directed rate-regulated utilities to file proposed Michigan-specific uniform BCA requirements by September 1, 2022 in that docket. The Commission stated that the proposal should contain an SCT and should be able to be used in multiple types of dockets, including pilot proposals, distribution planning, and rate cases. DTE Electric and Consumers jointly filed proposed requirements in Case No. U-20898 on February 1, 2023. On February 3, 2023, MEGA filed comments on behalf of Alpena Power Company, Upper Michigan Energy Resources Company, Upper Peninsula Power Company, and Northern States Power-Wisconsin, which "proposed a jurisdiction-specific test

(JST) for DERs, which takes a societal viewpoint of pilot costs and benefits, incorporating utility system, host customer, and societal value streams from the NSPM's [National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources'] impact inventory." November 21, 2024 order in Case No. U-20898.

On April 24, 2023, the Commission issued an order in Case No. U-20898 requesting comments on the proposed BCA requirements from interested persons. After analyzing the comments and providing further guidance on the BCA proposal, the Commission "launch[ed] a collaborative for the purpose of developing a spreadsheet-based or similar open source tool which will establish a new platform as a model for the required benefit cost analysis that accompanies requests for pilots, to be ready for use in 2024." October 12, 2023 order in Case No. U-20898 (October 12 order), p. 30. In the November 21, 2024 order in Case No. U-20898, the Commission found that the Staff has made significant progress in identifying sources of assistance in developing an open-source BCA tool, but that additional time is required to carry out the directives of the October 12 order. Therefore, the Commission extended the deadline for developing an open-source BCA tool to 2026.

The Commission is striving for consistency in the application of the open-source tool to leverage the decisions from Case No. U-20898 for DER and non-DER projects in TEPs. Until the collaborative develops an open-source BCA tool and guidance to be used by DTE Electric to evaluate its TEP programs, the Commission finds that DTE Electric's proposed TEP portfolio-level BCA is reasonable and prudent and should be approved. The Commission finds the parties' recommendations, including MEIU's request that DTE Electric consider societal benefits through the use of multiple cost tests and MNSC's proposal that the company assess marginal revenues from EVs on a service territory and system-wide basis, may have merit and encourages the parties to discuss and analyze these BCA frameworks in the BCA collaborative and in the utilities' TEPs.

D. Outage Credits

DTE Electric notes that in Case No. U-20836, it requested deferral and subsequent recovery of credits paid for outages caused by events outside the company's control. Accordingly, in the February 2 order, the Commission directed DTE Electric to work with the Staff to develop a proposal for limited recovery of outage credits. *See*, February 2 order, pp. 366-367. The company states that it "met with Staff to discuss outage cause codes credits, and the Company's ability to recover credits paid for outages that exceed the duration" limit set forth in the Commission's Service Quality and Reliability Standards for Electric Distribution Systems (SQRS), Mich Admin Code, R 460.744 (Rule 44), "Customer accommodation for failure to restore service after sustained interruption due to gray sky and catastrophic conditions," and the frequency limit in Mich Admin Code, R 460.745 (Rule 45), "Customer accommodation for failure to restore service during normal conditions." DTE Electric's initial brief, p. 293.

In this case, DTE Electric contends that it should be permitted to recover credits paid for outages that exceed the duration limits of Rules 44 and 45 if the outage was caused by: (1) transmission operator or other utility; (2) public interference, or (3) animal interference. DTE Electric's initial brief, p. 293. In addition, the company proposes to recover a portion of the total credits paid to customers if DTE Electric exceeds the outage frequency limit for the following conditions: (1) ice; (2) lightning; (3) wind; and (4) other weather. DTE Electric explains that its "rationale for including weather-related events for exceeding outage frequency limits (but not for exceeding the duration limit) is that the Company controls the restoration time when there is a weather event, but not the frequency with which weather events occur." *Id*. (internal citations omitted).

The company requests that "costs of bill credits for outages beyond its control be deferred for future recovery starting after the final order in this case, and to use account 182.3, Other Regulatory Assets, for that purpose. The deferred amounts would be reviewed for reasonableness and prudency in a subsequent general rate case." DTE Electric's initial brief, p. 293. DTE Electric avers that once the deferred amounts are approved, only then will the company begin amortizing and recovering the expenses. In addition, DTE Electric suggests working with the Staff to design a recovery mechanism for credits related to frequent outages.

The Staff agrees in part and disagrees in part with DTE Electric's proposal to recover billing credits from customers when the outage was caused by the transmission operator, another utility, public interference, or animal interference. The Staff asserts that:

> the Commission should maintain its prior position regarding the credits, as it did in MPSC Case No. U-20836. While Staff agrees with deferring the costs related to credits eligible for recovery, Staff's position is that recovery should be far more limited than what DTE Electric has proposed. For credits paid for outages that exceed the duration limit, only those outages caused by a transmission operator, or another utility should be recovered from ratepayers. For credits paid to customers for exceedance of the outage frequency limit, the recoverable portion of the total credit amount provided to ratepayers should correspond only to outages caused by the transmission operator, another utility, or public interference.

Staff's initial brief, pp. 167-168 (citing 6 Tr 5230). The Staff states that it is also open to further collaboration with the company and intervenors after the conclusion of this rate case to resolve this issue.

The Staff disagrees with DTE Electric's proposal to recover long-duration outage credits that are caused by public or animal interference. The Staff explains that "credits paid out due to events such as a car hitting a DTE Electric-owned pole or an animal damaging equipment could not be recovered from ratepayers, because restoring customers in a timely manner after car pole accidents or other public interference and animal interference is an expected utility function." *Id*., pp. 168-169 (citing 6 Tr 5231-5232). In addition, the Staff opposes the company's proposal to recover repetitive outages due to animal interference, ice, lightning, wind, or other weather "because the utility should be hardening or otherwise upgrading its distribution system to reduce or eliminate the occurrences of these types of outages." *Id*.

MNSC objects to the company's request to recover outage credits, stating that the "proposal is reflective of DTE Electric's continuing resistance to accountability for its performance as owner and operator of its distribution system." 6 Tr 3793. MNSC asserts that an outage exceeding the Commission's SQRS is due to the company's failure to timely maintain and repair its system and should not be recovered from customers. Furthermore, MNSC argues that "DTE Electric's proposal to recover bill credits for weather effectively excludes a majority of their outage occurrences and would completely undermine any accountability for ensuring that their distribution system is robust enough to provide satisfactory service." 6 Tr 3793-3794.

The DAAOs assert that "[t]he Commission should reconsider the establishment of increased, hourly, and automatic outage credits for all DTE customers" and "should update [the SQRS] so that outage credits better reflect the costs and inconvenience of outages to customers." DAAOs' initial brief, pp. 89-90 (citing 6 Tr 4432); *see also*, 6 Tr 4672-4674.

In addition, the DAAOs contend that DTE Electric should not be permitted to recover any outage credits from customers because it disincentivizes the company to improve reliability, DTE Electric is better situated than ratepayers to prevent and manage outages, and it allows the company to recover for all types of outages, which removes all responsibility from the company. *See*, DAAOs' initial brief, pp. 90-92. Furthermore, the DAAOs disagree with DTE Electric that the November 18 order permits the company to recover credits for outages caused by animal and weather interference. In the DAAOs' opinion, the "the Commission intended for DTE to be able to recover outage credits in only very limited circumstances, specifically excluding outages caused by weather and animal interference." *Id*., p. 93.

Ann Arbor agrees with the Staff that DTE Electric should be hardening or upgrading its system to reduce or eliminate outages due to animal and weather interference. Specifically, Ann Arbor states that:

> [t]he Company has already spent a significant amount of ratepayer money – and is planning to spend billions more over the next several years – to allegedly improve the grid. The capital invested to harden and/or upgrade the grid is added to the Company's rate base, which means not only is the cost of these investments borne by ratepayers, but DTE's shareholders also earn a return on these investments, which is also funded by ratepayers. In return, ratepayers should get a more reliable and resilient grid.

Ann Arbor's initial brief, p. 10. In addition, Ann Arbor objects to DTE Electric's claim that it should recover credits for outages caused by events outside the company's control, asserting that DTE Electric "does not provide a reason ratepayers should bear the cost of these outages that are inarguably far less within their nexus of control than the Company's." *Id*., p. 11. Furthermore, Ann Arbor argues that the $38/day outage credit is insufficient to compensate customers for replacing perished food, covering the cost of alternative shelter, and lost hours of productivity.

GLREA agrees with the DAAOs and Ann Arbor that the outage credit is inadequate to compensate customers. In addition, GLREA disagrees with DTE Electric that all weather-related outages are unavoidable, stating "that tree trimming and grid hardening programs have been shown to reduce weather related outages." GLREA's initial brief, p. 25. However, in conclusion, GLREA supports the Staff's recommended outage credit recovery proposal.

In its reply brief, DTE Electric states that it "maintains its original position, but believes Staff's recommendation is reasonable." DTE Electric's reply brief, p. 109. The company requests that the Commission reject the DAAOs' proposal to deny the company recovery of all outage credits because such an order would be contrary to the Commission's determination in the November 18 order. And, in response to the DAAOs' recommendation that the Commission revise the SQRS to provide an hourly, progressive, automatic credit, the company states that hourly credits were considered and rejected during the SQRS rulemaking process, and in any event, this is not the proper forum to dispute the rules.

In response to DTE Electric's contention that the Staff's proposal is reasonable, MNSC disagrees, asserting that it "does not support recovery of outage credits for frequency exceedance due to public interference. The Commission should reject DTE's proposal and limit recoverable outage credits to those caused by the transmission operator or another utility, and then only on condition that DTE seeks recovery of costs from the responsible party." MNSC's initial brief, pp. 154-155.

The DAAOs dispute DTE Electric's claim that the DAAOs are attempting to amend the SQRS in this case. To the contrary, the DAAOs assert that they are encouraging the Commission to "update its rules so that outage credits better reflect the costs and inconvenience of outages to customers." DAAOs' reply brief, p. 25. The DAAOs also maintain the position that DTE Electric should not be permitted to recover any outage credits for the reasons set forth in the DAAOs' initial brief.

GLREA replies that it appreciates the Staff's discussion of this issue. GLREA contends that:

> [o]verall, Staff's discussion may suggest that the criteria for allowing any rate recovery of outage credits is not yet sufficiently developed, and that allowing such rate recovery for purposes of this case is premature. Difficulties exist in defining when an outage is beyond the control of the utility (as the utility should proactively

> develop advance plans to quickly address outages) and to evaluate when an outage is unreasonably extended due to shortcomings in the utility's approach to restoring service.

GLREA's reply brief, p. 8. GLREA also recommends that the Commission should require DTE Electric to recover the costs of the outage from the third party who caused the outage, i.e., the transmission company, another utility, or an auto collision. However, in GLREA's opinion, recovery of outage credits should not be approved in this case and should be deferred to a future case, if at all.

Ann Arbor maintains its position as set forth in its initial brief. *See*, Ann Arbor's reply brief, p. 4. In the event the Commission approves recovery of certain outage credits, Ann Arbor requests that the Commission require DTE Electric to "provide evidence for each credit it intends to recover, so there is no chance that ratepayers will have to bear the cost of outage credits that were rightfully paid." *Id*.

On pages 366-367 of the November 18 order, the Commission directed DTE Electric "to work with the Staff toward the full development of the Staff's proposed limited recovery of outage credits" that were "caused by customer negligence or the transmission system operator, among other limited circumstances as developed in collaboration with the Staff." However, according to the Staff:

> [p]rior to the Company filing its subsequent rate case, Case No. U-21297, DTE Electric informed Staff that it would not be seeking cost recovery for any outage credits in that case, making full development of the proposal unnecessary at that time. When the Company filed Case No. U-21297, in February 2023, it did not contain a request for recovery of outage credits.

6 Tr 2340, filing #U-21461-0262 in Case No. U-21461. The Staff notes that DTE Electric's proposed recovery of outage credits in the immediate case is similar to the company's proposal in Case No. U-20836. *See*, 6 Tr 5230. Although DTE Electric states that it "met with Staff to

discuss outage cause codes credits, and the Company's ability to recover credits paid for outages that exceed the duration and frequency limits outlined in [Rule 44] and [Rule 45], respectively," the Commission finds that the company has yet to meaningfully collaborate with the Staff to develop a procedure for limited recovery of outage credits, as proposed by the Staff in Case No. U-20836 and supported by the Commission in the November 18 order. *See*, DTE Electric's initial brief, p. 293.

The Commission finds persuasive the Staff's position that the outage credits that are eligible for recovery should be deferred; however, recovery of the outage credits should be more limited than what is proposed by DTE Electric. Specifically, the Commission agrees with the Staff that:

> [f]or credits paid for outages that exceed the duration limit, only those outages caused by a transmission operator or another utility should be recovered from ratepayers.
>
> For credits paid to customers for exceedance of the outage frequency limit, the recoverable portion of the total credit amount provided to ratepayers should correspond only to outages caused by the transmission operator, another utility, or public interference.

6 Tr 5230. The Commission finds that the company should not recover long-duration outage credits for outages that are caused by public and animal interference because it is an expected utility function to restore customer service in a timely manner after auto collisions and animal interference with utility equipment. In addition, the Commission agrees with the Staff that credits paid for repetitive outages caused by animal interference, ice, lightning, wind, and other weather should "not be recovered from ratepayers, because the utility should be hardening or otherwise upgrading its distribution system to reduce or eliminate the occurrences of these types of outages." 6 Tr 5232.

The Commission also finds persuasive MNSC's and GLREA's requests that DTE Electric examine methods to recover the costs of an outage caused by the transmission company, another utility, or an auto collision. Furthermore, the Commission agrees with Ann Arbor that the company should provide evidence for each credit it intends to recover from customers to eliminate the risk that DTE Electric may recover credits that were justly paid to customers under the SQRS.

Therefore, the Commission once again directs DTE Electric to collaborate with the Staff to develop a procedure for limited recovery of outage credits, as described above, and directs the company to defer the costs for review and recovery in a future rate case using account 182.3, Other Regulatory Assets.

In response to the DAAOs' request that the SQRS be amended to create increased, hourly, and automatic outage credits for customers, the Commission notes that the SQRS are already designed to be automatic and recurrent, however on a daily, not hourly, basis. Furthermore, the outage bill credit is subject to an annual Consumer Price Index adjustment, and accordingly was amended to $40.00 in the September 5, 2024 order in Case No. U-20629. *See*, Rule 44(3).

Finally, while the Commission broadly agrees with GLREA's, Ann Arbor's, and the DAAOs' argument that the outage credit is not sufficient to fully compensate customers for financial hardships caused by outages, the Commission notes that the primary purpose of the credits is an accountability metric for the utility to provide service to customers within the parameters identified in the Commission's rules. When the utility fails to meet the parameters for restoration outlined in the SQRS, the rules ensure that, rather than a penalty paid to the State of Michigan, utilities provide an accommodation directly to customers. The Commission understands that this accommodation may be less than the losses or hardships experienced by certain customers, as it is designed as an accountability metric rather than a way to make customers whole. As such, the Commission declines to change the outage credit at this time.

E. Accounting Issues

1. Tree Trimming Capitalization

The Attorney General and MNSC, together AGMN, assert that the Uniform System of Accounts (USoA) permits capitalization of tree trimming expenditures "[o]nly in the specific circumstance of installing new facilities." 6 Tr 3949. AGMN claim that on pages 25-27 of the December 11, 2015 order in Case No. U-17767 (December 11 order), the Commission found that DTE Electric's Enhanced Vegetation Management Program (EVMP), now renamed the ETTP, is not a first clearing of rights-of-way and, thus, not a capital expenditure, but an O&M expense. In addition, AGMN contend that in the December 1 order, the Commission determined that it would be better to evaluate the issue of capitalizing tree trimming associated with hardening, conversion, and PTMM programs after the distribution audit of the company's tree trimming practice is complete, which is expected in late 2024. AGMN notes that the distribution audit is still pending and there has been no Commission decision on this issue. Therefore, AGMN continues to assert that including tree trimming in capital is contrary to USoA guidance and that it should be classified as an O&M expense. *See*, MNSC's initial brief, pp. 106-108. AGMN further request that the Commission:

- Require DTE in its next rate case to identify the extent that it capitalized tree trimming costs in each program, each year, from 2021 through 2024;
- Require DTE to present in its next rate case an analysis of the full costs to ratepayers resulting from its decision to capitalize tree trimming costs compared to the cost of on-cycle maintenance O&M trimming; and
- Require DTE in its next rate case to explain the legitimacy of its decision to capitalize tree trimming expenses for distribution capital programs.

6 Tr 3952-3953.

DTE Electric objects to AGMN's claim that pursuant to the USoA, "the only permitted capitalization of vegetation management spending is in the initial construction of a brand-new overhead distribution line." DTE Electric's initial brief, p. 296 (quoting 6 Tr 3951). The company notes that the USoA defines maintenance as "sustaining existing assets, and includes 'Replacing or adding minor items of plant which do not constitute a retirement unit.' The tree trimming activities capitalized by the Company relate to the installation of new assets (which *do* constitute retirement units), not to maintaining existing assets." DTE Electric's initial brief, p. 297 (quoting 6 Tr 1576) (emphasis in original); *see also*, DTE Electric's reply brief, p. 112.

DTE Electric also disputes AGMN's assertion that the Commission decided this issue in the December 11 order. The company asserts that "[t]he Commission addressed only the accounting for the EVMP (maintenance clearing of a corridor instead of a circle) in that case. The Commission did not opine on the capitalization of tree trimming as it relates to the installation or replacement of capital assets." DTE Electric's initial brief, p. 298. DTE Electric contends that AGMN misinterpreted the USoA and that AGMN's recommendation is not based on a full reading of the USoA. Thus, the company asserts that the Commission should reject AGMN's position that tree-trimming capitalization should be disallowed.

AGMN disagree with DTE Electric's interpretation of the USoA. First, AGMN state that:

> the Company makes no case that all capitalized trimming is related to installation of new assets. Moreover, the Company makes no case that any installed "new assets" are "retirement units." In fact, the Company failed to identify what programs or projects are associated with tree trimming that is capitalized, let alone identify the new assets being installed nor that those new assets are "retirement units" under the USOA. DTE has not shown whether replaced crossarms in Hardening or replaced insulators, cutouts, and arresters in PTMM are "retirement units" (as opposed to "minor property").

MNSC's initial brief, pp. 110-111 (footnote omitted). Second, AGMN contend that the company disregards the specific language in the USoA that addresses tree trimming associated with overhead distribution lines and, instead, relies on a broad reading of the general terms defining maintenance. AGMN assert that "[t]he USOA defines Account 365 *Overhead Conductors and*

Devices, which is the capital account for distribution line assets, to explicitly include 'Tree Trimming, initial cost.'" *Id*., p. 111 (emphasis in original).

Third, AGMN note that DTE Electric relies on a single item from the list in Operating Expense Instruction 2, which states: "Item 8. Replacing or adding minor items of plant which do not constitute a retirement unit. (See electric plant instruction 10)." *Id*. AGMN assert that according to the company, because it is replacing a retirement unit, it is not maintenance, and the company is permitted to capitalize the associated trimming. However, AGMN state that "this part of the USOA does not say or suggest that trimming associated with the replacement of 'retirement units' should be capitalized. It says that replacing a retirement unit (per Electric Plant Instruction 10) may not be maintenance." *Id*., pp. 111-112.

Fourth, AGMN contend that Account 593 of the USoA states that maintenance includes "'Work of the following character on overhead conductors and devices: . . . k. Trimming trees and clearing brush.'" *Id*., p. 112. AGMN aver that "[t]rimming is maintenance. Packaging trimming with capital replacements does not convert trimming into a capital expense." *Id*.

Finally, AGMN disagree with DTE Electric's claim that the Commission did not decide this issue in the December 11 order. AGMN state that in Case No. U-17767, the Commission found that the company's EVMP was not initial clearing, but instead subsequent trimming, and, thus, was not a capital expenditure. In conclusion, AGMN assert:

> [h]ere again, the Company overstates its own case – it has not shown that all capitalized tree trimming relates to the installation or replacement of capital assets, and in fact it appears that some aspects of the programs where tree trimming is capitalized undertake maintenance and repairs alongside or instead of installation and replacement. And even if the Company coordinates tree trimming with the installation or replacement of capital assets, that does not necessarily convert trimming into a capital investment. The Company must maintain its lines and equipment with adequate vegetation management; if its maintenance program is insufficient such that it requires additional trimming to install or replace equipment or components, that calls into question the adequacy of the maintenance program.

Id., p. 114.

In response to AGMN, DTE Electric asserts that MNSC raised this same issue in Case Nos. U-20836 and U-21297, which the Commission determined a decision should be deferred until the audit of the company's accounting practices for its distribution system is complete. DTE Electric states that:

> if MNSC had anything else to say about the matter, then it should have presented revised testimony or other new evidence as part of its direct case filing, and in accordance with its obligation to support its propositions. Instead, [AGMN] witness Alvarez rehashed the same arguments that MNSC witness Ozar made previously, to which the Company again (and appropriately) provided essentially the same responses that it provided in past cases where MNSC's requested relief was denied.
>
> Now, MNSC attempts to fault the Company for not providing a more expansive discussion and speculates about what might be said on issues that MNSC could have raised but did not. That approach cannot support a decision, and also raises due process concerns because the Company cannot present additional evidence to the new issues that MNSC now attempts to raise after the record was closed.

DTE Electric's reply brief, pp. 112-113 (footnotes omitted).

As stated on page 281 of the December 1 order and pages 471-472 of the November 18 order, the Commission expressed ongoing concerns with utility capitalization policies and that further action on this matter would be better made after the audit of DTE Electric's accounting practices for its distribution system is complete. The Commission notes that in the October 5, 2022 order in Case No. U-21305 (October 5 order), the Commission directed the Staff "to commence the process of hiring a consultant to perform a comprehensive, independent third-party audit and review of the distribution systems, including all equipment and operations, of [Consumers] and [DTE Electric]." October 5 order, p. 1. The Staff filed the requested audit results report on September 23, 2024, in Case No. U-21305. In the September 26, 2024 order in Case No. U-21305 (September 26 order), the Commission directed Consumers and DTE Electric to file responses to the audit results report no later than November 15, 2024, in Case No. U-21305. *See*, September 26 order, pp. 3-6. The Commission also invited interested persons to file initial comments on the audit report and the utilities' responses no later than December 16, 2024, and reply comments no later than January 17, 2025, in Case No. U-21305. Following the receipt of reply comments in Case No. U-21305, the Commission expects to issue an order in that case providing further guidance and next steps.

2. Capitalization Policies

In the November 18 order, the Commission stated that:

> [t]he Commission finds that concerns raised in this proceeding regarding capitalization policies are not limited to DTE Electric. Utility capitalization policies are an ongoing concern for the Commission which warrants further investigation. However, given the broad scope of capitalization concerns, the Commission declines to require a[n] [interested person] proceeding or a limited investigation specific to DTE Electric, at this time.

November 18 order, p. 471. With the audit report now filed, the Commission plans to set forth its next steps in evaluating utility capitalization policies in a separate proceeding in the near future.

3. Shared Assets

DTE Electric states that it "forecasted $63.5 million of revenue from shared assets (such as building and IT), assuming the capital projects in this case are approved. If the Commission disallows a capital project that is for a shared asset, then for consistency it must also remove the revenue related to that asset from projected net operating income." DTE Electric's initial brief, p. 299; DTE's reply brief, p. 113. The Commission finds that DTE Electric failed to provide sufficient evidence to support this request. The company, in its initial brief, p. 299, cites to "Exhibit A-36, Schedule BB1," and 6 Tr 1560, 1563-1564. The evidence explaining this request appears, rather, to amount to the testimony at the top of 6 Tr 1654 and Exhibit A-37, Schedule BB1, column (f). The Commission finds that the testimony is not sufficiently detailed to elucidate how the amounts in column (f) were arrived at.[50] For this reason, the Commission has not removed any revenue related to a disallowed shared asset from projected NOI. DTE Electric may seek this adjustment in a future rate case with additional evidentiary support.

IX. REVENUE DEFICIENCY

Consistent with the findings and determinations made in this order, the Commission finds that DTE Electric has a jurisdictional revenue deficiency for the test year of $217,380,000 computed as follows:

Rate Base	$21,787,037,000
Adjusted Net Operating Income	$1,188,411,000
Overall Rate of Return	5.45%
Required Rate of Return	5.69%
Income Requirements	$1,238,928,000
Income Deficiency	$50,516,000
Revenue Conversion Factor	1.3496
Revenue Deficiency	$68,179,000
Rev. Def. – Tree Trim Surge Program	$11,695,000
Rev. Def. – Monroe Reg. Asset	$137,505,000
Revenue Deficiency – Total	$217,380,000

[50] Additionally, Exhibit A-37, Schedule BB1, appears to be in error as it indicates it is in billions of dollars.

X. COST ALLOCATION AND RATE DESIGN[51]

A. Cost of Service Study

DTE Electric states that its unbundled cost of service studies (UCOSS) for the projected test year are consistent with past practices and Commission orders, including the cost-allocation methods approved in the December 1 order. The company explains that there are three steps to developing a UCOSS: (1) functionalization (which assigns all costs to the major functions, i.e. power supply and distribution); (2) classification (which divides these costs into customer-related costs, demand-related costs, and energy-related costs); and (3) allocation (which apportions the cost classifications to the respective classes of service based on the class's responsibility for the incurrence of these costs). DTE Electric's initial brief, p. 300 (footnote omitted). DTE Electric also explains how it functionalized the costs and how the UCOSS allocates the costs to the company's various customer classes. According to the company, it "will experience a jurisdictional revenue deficiency of approximately $456.4 million in the 2025 projected test year, consisting of a $148.7 million base production revenue deficiency, and a $307.7 million distribution revenue deficiency." *Id*.

Regarding production and transmission, DTE Electric proposes to use the same allocation methods that were approved in the December 1 order. The company states that it "uses three allocation bases for distribution: (1) demand, (2) customer, and (3) those based on special studies.

[51] GLREA argues that DTE Electric's proposed DG tariff sheet D-114-00 should be rejected by the Commission because, under MCL 460.1177(2), securitization charges should not be exempted from DTE Electric's DG customer outflow billing credit. GLREA's initial brief, pp. 16-22; GLREA's reply brief, pp. 5-7. GLREA notes that no testimony was provided on this issue by DTE Electric or any other party (including GLREA). GLREA's initial brief, p. 16. Tariff sheet D-114-00 is the subject of the proceeding in Case No. U-21798, which is pending. Tariff sheet D-114-00 was not filed by DTE Electric in the instant case. *See*, Exhibit A-16, Schedule F8. Thus, the Commission finds that this issue is not ripe for decision in this rate case.

The Company proposes to allocate distribution by voltage level class (residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals . . . ." DTE Electric's initial brief, p. 301 (footnotes omitted). DTE Electric notes that in the December 1 order, the Commission approved changes to the following allocation methodologies, which were used in this case: (1) EV program costs; (2) Rider 10 tax gross-up adjustment; and (3) demand-related distribution plant-related costs. The company asserts that Exhibit A-16, Schedules F1.1 and F1.2 contain DTE Electric's UCOSS for production by customer class and distribution by voltage class, respectively; Schedule F.3 contains the functionalization and allocation overview; Schedule F1.4 contains the customer charges by voltage class; Schedule F1.5 contains the capacity charge revenue requirement by customer class; and Schedules F1.6-F1.8 contain alternate COSS.

The Staff states that DTE Electric allocated purchased power capacity costs using allocator 251, which is based on 4 coincident peak (4CP) 100% demand, but excludes the R10 rate class. The Staff "does not agree with this allocation method because Staff views production assets, including those that provide purchased power capacity to the Company, as providing both energy and capacity." Staff's initial brief, p. 117. Rather, the Staff recommends using allocator 255, a 4CP 75-0-25 allocation, which is based on long-standing Commission practice.

MNSC contends that it is unreasonable for the company to allocate costs for distribution system maintenance and upgrades based on peak loads because it does not accurately account for the causes of transformer aging. *See*, 6 Tr 3845. MNSC explains "that because aging of line transformers occurs almost exclusively occurs [sic] during the summer months, utilization of the effective capacity of the distribution system is highly seasonal." MNSC's initial brief, p. 188. Accordingly, MNSC recommends that the Commission direct DTE Electric to file in its next rate case an analysis of the seasonality for cost causation of distribution costs and distribution rate designs consistent with that seasonality.

In addition, MNSC contends that single-family and multi-family residential customers have significantly different cost-of-service characteristics and, therefore, these customers should have different customer rate classes. Specifically, MNSC recommends that "the Commission require DTE Electric to present in its next rate case a cost-of-service study and corresponding rates in which residential customers are divided into Multifamily, Single-Family with electric space heating, and Single-Family with fossil-fueled space heating." 6 Tr 3796; *see also*, MNSC's initial brief, p. 191. MNSC contends that splitting the residential rate class by dwelling type results in a more accurate assignment of revenue responsibility to customers.

Furthermore, MNSC requests that the Commission direct DTE Electric to treat customers with electric space heating as a separate class. MNSC notes that the company has separate rate schedules for residential and commercial space heating, "but those rate schedules mostly require separate metering, which is an unnecessary expense to both DTE and the customer." 6 Tr 3797. MNSC contends that it will be less expensive and more sustainable to treat electric space heating customers as a separate class. The CEOs agree with MNSC, asserting that "the Commission should adopt a four-tiered residential rate structure because it will advance the State's decarbonization goals and encourage electrification" and will make electrification more accessible to low-income customers. CEOs' initial brief, p. 16.

DTE Electric responds to the Staff's proposed allocation method, asserting that its 4CP 100-0-0 demand allocation of purchased power capacity, less R10, has "been consistently applied in the calculation of approved tariffs in the previous seven DTE electric rate cases by DTE (U-17767, 18014, 18255, 20162, 20561, 20836, and 21297)." 6 Tr 2796. The company contends that its current allocation method is an appropriate reflection of cost causation. However, if the Commission approves the Staff's proposed method, the company states that "it would also be prudent to ensure consistency in the allocation of purchased power energy and fuel costs. Currently, fuel costs are allocated using using [sic] allocator 192 (12 CP 10-0-90)." 6 Tr 2797; *see also*, DTE Electric's reply brief, pp. 115-116.

ABATE objects to the Staff's request that DTE Electric's purchased capacity costs should be allocated using 4CP 75-0-25. ABATE explains that:

> Staff's proposal is inconsistent with the fact that the vast majority (95%) of these costs are related to renewable facilities required under Public Act 295 of 2008 [(Act 295)]. Specifically, the Company's owned renewable assets comprise 69% of the total while its PURPA [Public Utility Regulatory Policies Act of 1978] contracts and other renewable Purchased Power Agreements ("PPA") make up the rest, along with a small offset for DTE's capacity sales. These figures represent what DTE has determined to be the capacity related portion of these assets. In total, the [Act] 295 assets have a cost of $388.3 million, which cost DTE has separated into those which are "fuel related" (which is simply the portion of the asset cost that has not been deemed to be capacity-related based on the fixed-cost proportion of the transfer prices) and "capacity-related." From this delineation $130.4 million of these costs is capacity-related and $257.9 million is "fuel-related."

ABATE's initial brief, pp. 48-49 (citing 6 Tr 3508-3513; Exhibit AB-26, Schedule P2).

ABATE notes that under the Staff's proposal, 75% would be allocated based on energy and 25% would be allocated based on demand. However, ABATE argues that:

> [t]his proposal is inconsistent with the fact that 89% of DTE's costs for its owned renewable facilities are entirely fixed, meaning they have no material fuel costs. Indeed, renewable facilities like wind and solar assets have no fuel costs; the majority of the asset costs are incurred when they are installed with little variable production expense. In other words, regardless of customer energy consumption, or even energy generation, 89% of these costs would remain fixed and should be allocated as such. Allocating the capacity-related portion of the [Act] 295 renewable assets using the 4CP 75-0-25 allocator instead is therefore unreasonable and inconsistent with the nature of these assets and their costs.

ABATE's initial brief, p. 49 (internal citations omitted); *see also*, ABATE's reply brief, pp. 21-23. Therefore, ABATE requests that the Staff's proposed 4CP 75-0-25 allocator be denied and the company's proposal be approved. In the event the Commission decides to modify the allocation of DTE Electric's Act 295 renewable assets, ABATE recommends that they be allocated more on the basis of demand.

In response to MNSC's claim that transformer aging occurs almost entirely in summer months, DTE Electric states that "[t]hermal loading and ambient temperatures [are] only [two] of several factors including thru-faults and voltage impulses (switching surges, lightning, etc.) that can lead to transformer aging." 5 Tr 1268-1269. The company acknowledges that transformers may age at a faster rate in summer months when they experience high load. However, DTE Electric argues that "if a transformer were to be fully loaded for 1 year in a cold/winter climate, it would have 1 year worth of life of the transformer consumed as well." 5 Tr 1269.

The company also asserts that MNSC's recommendation that the Commission require DTE Electric to perform an analysis on seasonality and distribution costs is insufficiently detailed. DTE Electric states that "[i]t is unclear if [MNSC] is suggesting an independent study or a supplemental COSS to assess the seasonality of distribution cost causation. Questions such as whether the study should cover only plant costs or include operating and maintenance expenses, or whether it should encompass an examination of distribution allocators in the COSS are not addressed in MNSC's testimony." 6 Tr 2793; *see also*, DTE Electric's reply brief, p. 114. The company contends that MNSC's suggested study would require significant time and resources, which is unnecessary "to fill some undefined future data interest." 6 Tr 2793.

DTE Electric also objects to MNSC's recommendation that the company study separate residential rate classes and rate design by dwelling and a separate electric space heating cost of service and rate design. DTE Electric contends that it cannot conduct this type of study because:

> the Company does not know which residential customers are single v. multifamily (either including or excluding duplexes and mobile homes, as [MNSC] Witness

> Jester suggests should be classified as single family "since these appear to have similar load profiles"). In addition, unless customers are utilizing a specific rate product or program which requires them to specific [sic] appliances they are using (e.g. electric space heating on D2), the Company has no way of knowing which appliances any given customer uses.

6 Tr 2621 (quoting 6 Tr 3796). Additionally, even if the relevant data was available, DTE Electric argues that the distinction between single family, multi-family, and heating source is not a uniquely important driver of load characteristics. *See*, DTE Electric's reply brief, p. 120. Furthermore, DTE Electric states that "MNSC did not show any specific significance to single v. multifamily or electric space heating as it concerns which usage drivers ought to be considered for their own cost of service class." DTE Electric's reply brief, p. 121.

The Staff agrees with DTE Electric "that a reexamination of the appropriateness of the allocation of energy-related costs, particularly the 12 CP 10/0/90 allocator for fuel, is necessary. Both energy and fuel costs are directly energy-related and should be allocated based on energy." Staff's initial brief, p. 119. The Staff notes that Michigan's other large electricity provider, Consumers, allocates both purchased power energy and fuel costs using 100% energy allocators. Regarding purchased power capacity costs, the Staff maintains its position that the Commission should approve the Staff's 4CP 75-0-25 allocator. MNSC agrees. *See*, MNSC's reply brief, pp. 31-33.

The Staff disagrees with ABATE's claim that DTE Electric's purchased power capacity costs are largely related to renewable energy assets and that the company's Act 295 renewable resources are mostly fixed-cost assets. The Staff states that:

> renewable resources are not all capacity as demonstrated on Exhibit A-26, Schedule P2. On this exhibit the Company uses the fixed and variable components of the transfer price to proportionally split renewable costs between capacity-related and fuel-related. Exhibit A-26, Schedule P2 illustrates that approximately 33.6% of renewable resources are determined to be capacity-related and 66.4% are determined to be fuel-related.

Staff's reply brief, p. 8. In the Staff's opinion, whether some portion of renewable costs are considered to be fuel for the offset calculation is not relevant to the portion that is considered capacity related. Therefore, the Staff requests that ABATE's position on this issue be rejected.

In response to MNSC's proposed COSS that creates new customer classes for residential electric heating and multi-family dwellings, the Staff notes "that electric heating customers are already separated in the COSS and have a different rate design than other customers. It is unreasonable to only differentiate residential heating source for single-family but not multi-family dwellings." Staff's initial brief, p. 125 (citing 6 Tr 4908-4909). The Staff states that if both heating source and the type of dwelling are significant drivers of differences in the cost to serve customers, then these variables should be studied in a future COSS. In the event the Commission approves MNSC's recommendation, the Staff requests "that the Commission require the Company to file in its next case an alternative COSS that separates residential customers into multi-family, single-family with electric space heating, and single-family with fossil-fueled space heating [and] that the Company further separate[s] multi-family with electric space heating customers." *Id.*, p. 126.

Regarding MNSC's recommendation that DTE Electric provide a "robustly time-differentiated rate structure that is available to electric heating customers," the Staff asserts that MNSC "did not elaborate on what a 'robust' rate design means." *Id.*, p. 126 (quoting 6 Tr 3831). Rather, the Staff argues that an electric heating customer rate design must be cost based, and:

> this means that, like the Company's default residential rate, the difference in price by time period must be based on some measure of actual costs. By law DR rates must be voluntary. A "robust" rate design like that of DR rates which charge much larger pricing differentials in order to induce load shifting, such as the DPP [dynamic peak pricing] program Rate D1.8, are not cost-based in the traditional sense because they attempt to produce a customer behavior that will actually influence future costs.

Staff's initial brief, p. 126 (citing 6 Tr 4912). Thus, the Staff asserts that the Commission should not require DTE Electric to provide a residential electric heating customer rate that is not based on some measure of actual costs.

DTE Electric objects to the Staff's proposal that the company provide in its next rate case an alternative COSS that separates residential customers into multi-family, single-family with electric space heating, and single-family with fossil-fueled space heating, and that the Company further separate multi-family with electric space heating customers. The company asserts that the "Staff provides no guidance or evidentiary support on how such an alternative COSS would be completed. Staff also fails to acknowledge the Company's threshold concern that, 'the actual information required to conduct such a study does not exist.'" *Id*., p. 122 (quoting 6 Tr 2621). Moreover, DTE Electric contends that the CEOs' proposal to adopt a further modified rate design should be denied for the same reason.

Responding to MNSC's request that DTE Electric file in its next rate case a seasonal approach to distribution rates, ABATE asserts that:

> [i]n general, utilization does not align with cost causation unless either the cost in question involves incurring a variable cost based on utilization, or the utilization period is limited to demand in the specific hours that cause the utility to incur infrastructure costs. Thus, just because a distribution transformer's loss of life may be higher in certain seasons than others does not mean the allocation of all distribution costs should be based on seasonal utilization, even if distribution equipment ratings are sensitive to ambient temperature.

ABATE's initial brief, pp. 47-48 (citing 6 Tr 3415-3416); *see also*, ABATE's reply brief, pp. 20-21. Therefore, ABATE recommends that the Commission deny MNSC's request.

MNSC disagrees with DTE Electric that a seasonality and distribution cost study is unnecessary. In MNSC's opinion, the company's "dismissal of the benefits of evaluating distribution cost causation seasonally appears not to have considered [MNSC Witness]

Mr. Jester's testimony about the benefits of allocating distribution costs seasonally in combination with creating residential subclasses for multi-family and electric heating customers." MNSC's initial brief, p. 189. Additionally, MNSC contends that ABATE erroneously asserted that MNSC is requesting that the allocation of all distribution costs be based on seasonal utilization. MNSC argues that it is merely recommending that the Commission require certain information to be filed in DTE Electric's next rate case. *See*, MNSC's initial brief, pp. 189-190.

In response to DTE Electric's claim that it does not have the data to separate the residential rate class by dwelling type and heating source, MNSC states that this is not the point—rather, the point is that MNSC's analysis of this issue demonstrates that a study is needed. Even so, MNSC contends that "[a]s a large, sophisticated utility, DTE has sufficient expertise to investigate these issues using sampling techniques. Certainly, the Commission can take notice that DTE demonstrates proficient use of similar techniques for EWR program investment decisions. A good place to start is whether customer addresses contain an apartment or unit number, or just a street number." MNSC's initial brief, p. 193. In addition, MNSC disputes the company's claim that there is no meaningful distinction between the cost to serve single family versus multi-family dwellings. MNSC argues that DTE Electric failed to provide evidence supporting this conclusion.

The CEOs assert that the Commission should reject DTE Electric's claim that it does not have the data to separate customers by dwelling and heating type and that, even if the company did, the differences do not justify different rate classes. The CEOs request that the Commission direct the company "to begin collecting data on single-family versus multi-family and electric versus non-electric heating customers. This data will not only facilitate more accurate rate designs but also support Michigan's broader energy goals by enabling better-informed decisions about grid modernization, electrification, and customer impact in future rate cases." CEOs' reply brief, p. 5.

In addition, the CEOs state that the peak demands for electric space heating customers and fossil fuel heating customers differ, these customers utilize the grid differently, and they have distinctive load factors. Therefore, the CEOs request that the Commission direct DTE Electric "to study and propose a new set of tariffs to match the distinct load profiles of residential customers based on home type and heating type." CEOs' reply brief, p. 6.

The Commission finds that the Staff's proposed 4CP 75-0-25 allocation of purchased power capacity costs should be approved. The Commission notes that this issue was recently addressed in the March 1, 2024 order in Case No. U-21389 (March 1 order), Consumers' general electric rate case as follows: "[t]he Commission has long recognized the 'dual nature' of production assets: 75% demand and 25% total energy usage." March 1 order, pp. 235-236 (citing May 10, 1976 order in Case No. U-4771). The Commission agrees with MNSC that, pursuant to MCL 460.11(1), "[p]urchased power capacity costs are plainly 'production-related costs.'" MNSC's reply brief, p. 32. Although DTE Electric recommends that the Commission retain the company's 4CP 100-0-0 allocation method, the company does not substantively object or provide sufficient evidence to counter the Staff's proposal to apply a 4CP 75-0-25 allocator.

The Commission finds ABATE's argument unpersuasive that a significant portion of DTE Electric's costs for its renewable facilities are entirely fixed, meaning they have no material fuel costs and should be allocated as such. As noted by the Staff, Exhibit A-26, Schedule P2 demonstrates that DTE Electric's renewable resources costs are split between capacity-related and fuel-related. The Commission agrees with the Staff that "fixed costs do not automatically equal capacity costs and that a capacity-related cost does not call for a pure capacity 100% demand allocation. Even if a renewable resource is a fixed cost asset, this does not automatically make that resource completely capacity related." Staff's reply brief, pp. 8-9.

The Staff also noted that if the Commission approves the Staff's proposed 75-0-25 allocation of purchased power capacity costs, the 12CP 10-0-90 allocator for fuel should be reexamined to ensure consistency in the allocations of purchased power energy and fuel costs. The Commission agrees and directs DTE Electric to submit a new allocator for fuel in its next rate case.

The Commission respectfully declines to adopt MNSC's request that DTE Electric be directed to file in its next rate case an analysis of the seasonality for cost causation of distribution costs and distribution rate designs consistent with that seasonality. The 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. *See*, 6 Tr 2621; Staff's initial brief, p. 126; DTE Electric's reply brief, p. 120.

In addition, the Commission respectfully declines to approve MNSC's request that the company study separate rate classes and rate design by dwelling and a separate space heating cost of service and rate design. Although DTE Electric may be able to use billing addresses to approximate which residential customers are single-family versus multi-family using their addresses, the company states that unless the customer is utilizing a specific rate or program for a specific appliance, DTE Electric cannot determine what appliance a customer uses. The Commission finds that MNSC did not provide evidence to refute this claim, nor did MSNC sufficiently demonstrate the benefits of their proposal.

B. Rider 10

In its initial brief, DTE Electric explains why the Commission should not adopt ABATE's proposal to modify the Rider 10 tariff. *See*, DTE Electric's initial brief, p. 304. Then, in its reply brief, the company states that "ABATE does not appear to pursue [this issue] in briefing." DTE

Electric's reply brief, p. 116. The Commission agrees with DTE Electric that ABATE did not pursue this issue in briefing and the Commission considers this issue abandoned.

C. State Reliability Mechanism Capacity Charge

DTE Electric states that the company's proposed capacity charge revenue requirement is set forth in Exhibit A-16, which was calculated using the method approved in the December 1 order and includes all production-related costs, with the exception of adjustments for fuel, variable O&M, MERC, and specific purchase power costs. The company explains that:

> the total projected 2025 wholesale energy revenue of $2.184 billion, net of $1.201 billion in fuel-related costs, equates to $0.983 billion wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26, Schedule P3, line 22.
>
> Company witness Maroun further explained that he used the same methodology utilized in Case No. U-21297 to calculate the MERC revenue requirement. Mr. Maroun also reduced the capacity charge revenue requirement for non-capacity related purchased power. He did so because these costs are for energy charges purchased from MISO for Rider 3 and Rider 10 and other energy related purchased power. Mr. Maroun adjusted variable O&M by including Account 501 (Fuel Handling), and the non-labor portions of Accounts 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker Expenses). This is consistent with Chapter 4 of the NARUC [National Association of Regulatory Utility Commissioners] Manual, which reflects that labor expenses are considered demand-related, while material expenses are considered energy-related. Thus, only material-related costs are variable.
>
> The resulting total capacity charge revenue requirement is $973.7 million. Mr. Maroun allocated it to the various rate classes using Allocator 251, 4CP (Schedule 200B) excluding R10, which is the methodology approved in Case No. U-21297.

DTE Electric's initial brief, pp. 304-305 (internal citations omitted).

The Staff contends that DTE Electric's capacity revenue requirement method is not consistent with the method approved in the December 1 order. Rather, the Staff asserts that to comply with MCL 460.6w(4) and the December 1 order, the company should have provided a reconciliation of net sales benefit difference, "which Staff interprets as requiring that a true-up be performed and included in the capacity charge calculation each year, regardless of whether a charge was administered in that year or not." Staff's initial brief, p. 111. Using the correct calculation, the Staff avers that the company's capacity revenue requirement is $1,035.6 million. 6 Tr 4947-4948.

The Staff objects to DTE Electric's SRM calculation and provides an alternative calculation. The Staff explains that:

> the required reconciliation of projected energy sales revenue net of fuel costs to the actuals, calculated as the value of the Company's generation at the locational marginal price (LMP), has the potential to drive the capacity charge unreasonably low or high depending on the relationship between the Company's costs to produce that energy and both actual and projected LMPs. In addition, the current capacity charge method produces increasingly questionable results the more a utility relies on purchased power agreements for the provision of power to its customers.

6 Tr 4962. Accordingly, the Staff recommends that costs that are incurred to supply capacity should be included in the SRM calculation as capacity-related costs. The Staff contends that "the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a combustion turbine (CT)," because it is an expensive plant to run, less expensive to build, and only economically useful to supply energy when load is at its highest. 6 Tr 4963; *see also*, Staff's initial brief, p. 137. For the value of capacity, the Staff recommends using MISO zone 7 CONE or the cost of capacity used for PURPA generator payments from the period most closely matching the test year.

However, the Staff states that there is a potential issue with its proposed alternative:

> As all energy is bid into the market at the cost to run a plant, but plants are paid if dispatched at the highest bid called in the supply stack, these net-energy market sales (imperfectly) capture what Staff would consider to be the energy related portion of capacity costs. Therefore, to remove all costs above a CT and then apply an offset which effectively, if imperfectly, does the same, would be double counting the offset.

6 Tr 4963; *see also*, Staff's initial brief, p. 138. To avoid this double-counting, the Staff asserts that:

> the revenue produced from energy sales into the market resulting from plants producing above the use of the Company's customers should be included as an offset to the cost of the capacity used to produce that energy. In fact, Section 6w(3)(b) of [Public] Act 341 [of 2016] expressly requires revenue from "all energy market sales" be included as an offset to the cost of capacity. Beyond the statutory requirement, it is the appropriate disposition of such revenue, as it is the additional capital expenditure over that of a CT which enables the production of energy at a cost low enough to make money in the market. Therefore, revenue from such sales should be used to offset the higher capital expenditures required to enable them. The Commission recognized similar principles in Case No. U-12639, by using net revenues from third party sales to offset fixed generation costs.

6 Tr 4964-4965 (internal citation omitted); *see also*, Staff's initial brief, p. 138. The Staff requests that if the Commission approves the Staff's proposed alternative SRM calculation, the Commission should direct DTE Electric to file in its next general rate case an SRM calculation consistent with the proposed alternative.

GLREA provides several general comments regarding capacity adequacy in Michigan and "recommends more effective TOU rates, DR programs, geo-targeted load-relief incentives, and battery deployments in the interest of both affordability and reliability." *See*, GLREA's initial brief, pp. 2-4.

Energy Michigan contends that in DTE Electric's SRM capacity charge calculation, there are purchased power costs of $2,925,000 for "Fuel Related Generation Cost based on the difference of total projected PURPA PSCR [power supply cost recovery] Cost and the Capacity Related Generation Cost" and $257,862,000 for "Fuel Related Generation Cost based on the difference of total projected [Act] 295 PSCR Cost and the Capacity Related Generation Cost" that are neither capacity costs nor fuel costs. Energy Michigan's initial brief, p. 4. According to Energy Michigan, "[t]hese costs are merely non-capacity costs left over when DTE subtracted the total costs of the purchased power from the amount that DTE designated as capacity costs, as DTE explains in footnotes to Exhibit A-26, Schedules P1 and P2." *Id*. Energy Michigan asserts that the true fuel cost is $940,245 that was calculated in Case No. U-21425, which is set forth in Exhibit EM-4. Therefore, Energy Michigan states that "the calculated net offsets are too low by $260,787 (000) in the determination of the SRM Capacity Charge in DTE's Exhibit A-16, Schedule F1.5 revised, page 1, column (a). This error -- caused by a misuse of the 'fuel' label -- has to be corrected." Energy Michigan's initial brief, pp. 6-7. Energy Michigan argues that the correct projected 2025 energy sales revenue net of fuel should be a negative $1,244,134, which results in an SRM capacity charge of $159.10 per MW/day.

In addition, Energy Michigan contends that:

> the SRM process was intended to accomplish the following: if an AES [alternative electric supplier] does not demonstrate that it will meet its capacity obligation to MISO, then the AES will pay the SRM Capacity Charge to the local utility, and the local utility will take on the responsibility for meeting the AES's capacity obligation to MISO. The taking on of that responsibility is a service that the utility provides to the AES. That service has a cost, and that cost now varies by season. Yet the current method of determining the cost of the SRM Capacity Charge results in an annual charge. Consequently, the Cost-of-Service statute (MCL 460.11(1)) comes into play.

Energy Michigan's initial brief, p. 9. Energy Michigan states that if the SRM capacity charge is to be consistent with cost-of-service principles, it must be set at the MISO seasonal auction clearing price (ACP), and that charge should be applied to the MW value of the deficiency for the days of the season that the load-serving entity (LSE) is deficient. According to Energy Michigan, "[t]his would comport exactly with the cost of providing the service -- the service of satisfying the MISO capacity obligation -- that the LSE/customer receives. This option is exactly consistent with the plain words of the Cost-of-Service statute." 6 Tr 4182.

DTE Electric asserts that Energy Michigan incorrectly calculated the SRM capacity charge. The company states that:

> [Energy Michigan] Witness Zakem only removed the $260.787 million value from fuel costs used to calculate the "energy sales revenue net of fuel costs" in Exhibit

> A-26 and used in Revised Exhibit A-16, [Schedule] F1.5, page 1 of 6. If the $260.787 million is not considered "fuel", then this amount would be considered a capacity-related cost. The same $260.787 million amount shown on Revised Exhibit A-16, [Schedule] F1.5, line 5, would also need to be removed. Correcting for this oversight made by Witness Zakem in his Exhibit EM-6, in his rebuttal, Witness Maroun provides Exhibit A-38 Schedule CC2 that removes the $260.787 million on line 5, column (b) which shows the calculation resulting in the original SRM capacity charge of $217.30/MW-day. Thus, Witness Zakem's recommended removal of the calculated PPA and Company Owned renewable "fuel-related" costs from the "energy sales revenue net of fuel costs" would have no impact on the $217.30/MW-day SRM capacity charge.

6 Tr 2348-2349; *see also*, DTE Electric's initial brief, pp. 305-307; DTE Electric's reply brief, p. 117. In addition, DTE Electric contends that Energy Michigan's recommendation to determine the SRM capacity charge by season creates additional unnecessary burdens for the company. Furthermore, the company avers that Energy Michigan's "proposal to tie the SRM capacity charge to the MISO Auction Clearing Prices is short sighted as the MISO's Planning Resource Auctions (PRAs) do not ensure long-term resource adequacy." 6 Tr 2350; *see also*, DTE Electric's initial brief, p. 306; DTE Electric's reply brief, p. 117. The Staff agrees. *See*, Staff's initial brief, p. 115.

Regarding the Staff's proposed alternative SRM capacity charge calculation, DTE Electric disagrees that the proper cost of capacity is CONE. The company contends that "[t]he cost of the Company's capacity fleet is based on many diverse resources required to maintain a reliable grid. Staff also suggests that its proposed alternative avoids pitfalls, but did not provide a sample calculation to prove how it may fluctuate during high and low market prices." DTE Electric's initial brief, p. 307; *see also*, DTE Electric's reply brief, p. 119.

Energy Michigan disagrees with DTE Electric that, pursuant to Energy Michigan's claim, the $260.787 million must be a capacity cost. Energy Michigan states that the company:

> has admitted on the record that the ~$260M in "fuel-related" costs are not capacity costs by excluding them from production costs on Schedule F1.5, page 1, line 5 of Exhibit A-16. It cannot on rebuttal (or in briefing) turn around and claim—without evidence and with only the support of an illogical argument—that those costs really

> are capacity costs after all just because they are not properly fuel costs. Neither can it reasonably claim without any record evidence that "the costs from its power purchase agreements which it labeled 'fuel-related' are actually fuel costs."

Energy Michigan's reply brief, p. 3 (quoting Energy Michigan's initial brief, pp. 6, 8). Energy Michigan contends that the Commission has not permitted utilities to use non-capacity, non-fuel costs in the SRM capacity charge calculation. In Energy Michigan's opinion, DTE Electric is "falsely claiming that the Commission is left with no option but to include its 'fuel-related' costs <u>somewhere</u> in the SRM Charge calculation [and this] should be rejected as poor logic and a poor attempt at obfuscation." *Id*., p. 4 (emphasis in original).

In response, DTE Electric states that Energy Michigan fails to support its claim that some costs are neither fuel nor capacity. The company asserts that:

> [t]his does not make logical sense since all costs associated with generation assets need to be recovered and should be somehow incorporated as part of the SRM capacity charge calculation. Any customer that pays the SRM capacity charge is receiving the full benefit from the Company's generation, thus all costs need to be included and the simplest way is to categorize them as either fuel or capacity.

DTE Electric's reply brief, p. 117.

Energy Michigan objects to the Staff's true-up method, stating that "[i]t has been almost seven years since the initial orders implementing the SRM capacity charge" were approved, and "[n]ot one customer has paid an SRM capacity charge. The SRM true-up as presently implemented does not and cannot work. A more straightforward, cost-based approach is needed." 6 Tr 4195. As an alternative, Energy Michigan recommends the following process:

> a. ***True up only if charged*** -- True-up to energy sales and fuel if and only if a customer actually pays the SRM Capacity Charge.
> b. ***Apply the SRM Capacity Charge the same way it is determined, by MW*** -- apply the SRM Capacity Charge directly to the MW of deficiency, rather than spread to rate classes in rates and collected over energy and demand.
> c. ***True up the same way the SRM Capacity Charge is applied, by MW*** -- the true-up should be paid or collected using the same MW number for which the

> customer paid the SRM Capacity Charge. If the customer was assessed 1 MW of SRM, then the customer gets 1 MW of true-up.

Energy Michigan's initial brief, pp. 16-17 (emphasis in original).

The Staff disagrees with Energy Michigan's claim that MISO's capacity obligation is imposed on LSEs by multiplying the ACP by the planning reserve margin requirement (PRMR) and then charging the result to the LSEs. Rather, the Staff contends that "MISO telling LSEs the capacity they need to cover is how the obligation is imposed, and the auction (by paying and charging in equal measure for covered capacity) only truly charges for any amount an LSE is short in covering its obligation." Staff's initial brief, p. 139; *see also*, Staff's reply brief, p. 26. The Staff also objects to Energy Michigan's assertion that the ACP is the cost of fulfilling an LSE's capacity obligation. The Staff states that:

> "[t]o the extent an LSE has the ZRCs [zonal resource credits] to support its [PRMR], the cost of satisfying the requirement is the cost of obtaining those ZRCs." The Company serves its customers' (including those AES customers whose capacity is not supplied by the AES) capacity with all of its capacity resources. This is properly recognized by the applicable statute requiring that full-service and AES load have the same capacity charge, such that the cost to serve either set of customers is the same; this cost is not the ACP.

Staff's initial brief, pp. 139-140 (quoting 6 Tr 4969).

In addition, the Staff asserts that Energy Michigan "seems to imply throughout direct testimony that the LSE is financially responsible for paying the capacity charge to the Company." 6 Tr 4970. The Staff disagrees, stating that in the November 21, 2017 order in Case No. U-18239 (November 21 order), the Commission found that the capacity revenue requirement should be allocated to the classes using the 4CP allocator, and then used to calculate a capacity rate for each schedule. In addition, the Staff avers that pursuant to the Commission's determination in the November 21 order, "the capacity charge must be the tariffed rates for capacity service applied to both full-service and AES customers bas [sic] on the interpretation of the controlling statute." Staff's initial brief, p. 141 (citing 6 Tr 4971); *see also*, Staff's reply brief, p. 27.

The Staff disagrees with Energy Michigan's claim that the Commission should eliminate from the SRM capacity charge a true-up of previous estimates if DTE Electric has not applied the SRM capacity charge to any party. The Staff states that MCL 460.6w(4) "does not direct the Company to true-up the capacity charge only if it was charged to a particular party, but rather the statute directs the Company to true-up the projected net revenue amounts used to calculate the capacity charge with the actual net revenue amounts that occur during the period and reflect them in the capacity charge in the subsequent year." Staff's initial brief, p. 115; *see also*, Staff's reply brief, p. 9. The Staff contends that Energy Michigan's alternative recommendations for the SRM capacity charge are needlessly burdensome, fail to provide sufficient benefits, and do not comply with MCL 460.6w(4).

Energy Michigan asserts that DTE Electric misunderstands Energy Michigan's proposal to set the SRM capacity charge seasonally based on MISO's seasonal auction price. Energy Michigan clarifies that its proposal "is to <u>set</u> the SRM Capacity Charge at an <u>existing, visible, cost-based price that MISO sets by season, the MISO seasonal Auction price</u>, and bill the charge directly by MW rather than include the charge in the design of each rate as is done presently. The amount of analytical effort to accomplish this is virtually zero, because the price is determined by MISO." Energy Michigan's initial brief, p. 12 (emphasis in original). Energy Michigan contends that an SRM capacity charge determined by an annual analysis does not comport with MCL 460.11(1).

Energy Michigan also disputes DTE Electric's claim that MISO's PRAs do not ensure long-term resource adequacy. Energy Michigan asserts that "[t]here certainly have been a variety of perspectives over the last 10 to12 years on the effectiveness of the MISO process, and DTE is entitled to its opinions. Likewise, in Energy Michigan's view, the current SRM Capacity Charge process arguably has no effect on resource adequacy, either." Energy Michigan's initial brief, p. 13.

Next, Energy Michigan claims that according to the Staff, Energy Michigan's proposal to set the SRM capacity charge at the MISO seasonal auction price should be rejected because "[t]he cost to meet MISO's capacity obligations is really the cost in a retail customer's rate after the SRM Capacity Charge is allocated across retail rates." Energy Michigan's initial brief, p. 13. Energy Michigan disagrees, stating that "the 'cost' that is relevant to the service to an AES of the utility satisfying the AES's capacity obligation to MISO is the cost to the utility, not the cost to the customer. Energy Michigan makes this clear in its recommendation and explanation." *Id.*, p. 14; *see also*, Energy Michigan's reply brief, pp. 4-5. Thus, Energy Michigan asserts that the Staff's claims on this issue should be disregarded.

Although Energy Michigan agrees with the Staff that there are problems with the way in which the company's SRM capacity charge is determined, Energy Michigan contends that there are some "complexities" to setting the SRM capacity charge to CONE, as suggested by the Staff:

1. A demonstration of capacity sufficiency under the SRM statute now can be done only by season.
2. A single annualized CONE does not fit a utility's cost of satisfying an AES's capacity obligation to MISO.
3. The annual Auction price used to have a cap of annual CONE, but now with the seasonal auctions, the seasonal auction prices could be CONE, or 1-1/3 times CONE, or two times CONE, or four times CONE.
4. MISO continues to develop and change its capacity obligations structure. A recently approved "Reliability Based Demand Curve" will result in Auction prices higher than the highest priced capacity needed to meet the MISO region requirement, plus raise the total capacity obligation higher than the greatest amount of capacity needed to meet the MISO reliability standard.

Energy Michigan's initial brief, pp. 19-20 (footnote omitted). Energy Michigan reiterates that the Staff's proposed SRM capacity charge method may conflict with MCL 460.11(1) and requests that the proposal be denied.

The Commission finds that DTE Electric's proposed capacity charge revenue requirement method should be approved, with the exception of the true-up. The Commission agrees with the Staff that pursuant to MCL 460.6w(4), the company should perform an annual true-up and include the utility charge or credit in the capacity charge in the subsequent year. Therefore, the Commission adopts the Staff's proposed capacity revenue requirement calculation of $1,035.6 million, which includes the annual true-up. *See*, 6 Tr 4947-4948; Staff's initial brief, p. 115; Staff's reply brief, p. 9.

The Commission respectfully declines to adopt Energy Michigan's argument that DTE Electric miscalculated the fuel cost for the SRM capacity charge. The Commission finds persuasive DTE Electric's position that if Energy Michigan's proposed values are used correctly in the SRM capacity charge calculation, it has no impact on the $217.30/MW-day SRM capacity charge calculated by the company. *See*, 6 Tr 2348-2349; DTE Electric's reply brief, p. 117.

DTE Electric and Energy Michigan object to the Staff's proposed alternative SRM calculation, and Energy Michigan recommends an alternative process. The Commission notes that this issue was most recently addressed in the March 1 order, which stated that "Case No. U-18239 is the proper venue to address SRM calculation methodology issues." March 1 order, p. 291. If DTE Electric or the intervenors would like to amend the SRM calculation methodology, they may petition the Commission to reopen Case No. U-18239. *See*, December 1 order, p. 307, and December 22, 2021 order in Case No. U-20963, p. 385.

D. Residential Rate Design

1. Rate Schedule D1.6 Transition and Closure

DTE Electric notes that in Case No. U-21297, the company proposed to amend the low-income assistance (LIA) program (which provides low-income customers a $40 monthly credit) by eliminating Rate Schedule D1.6 and transitioning these customers to Rate Schedule D1.11, which is the company's standard residential service rate with time-variable rates. In addition, DTE Electric asserts that in Case No. U-21297, the company proposed extending the LIA credit to all residential base rates. DTE Electric notes that the Commission declined to approve the company's proposed changes, requesting that DTE Electric first perform an impact study before retiring Rate D1.6 and transitioning customers to Rate D1.11, and also directing the company to revisit the issue in its next general rate case. *See*, DTE Electric's initial brief, p. 310.

DTE Electric states that it conducted a study on the impact of shifting customers from Rate D1.6 to D1.11, TOU, as directed by the December 1 order:

> which showed that the average impact was a 0.17% bill decrease. There is a narrow distribution of bill changes when comparing D1.6 and D1.11. The average change is a very slightly lower bill on D1.11. All else being equal, 58% of customers in the analysis would see a lower bill on D1.11. This near-zero positive average impact confirms that there is no structurally-adverse impact of transitioning D1.6 customers to D1.11. Company witness Willis further explained that Rate Schedule D1.6 maintains the "inverted block rate" structure. With the wide implementation of advanced meters, TOU is now a more precise way to design rates.

Id., pp. 310-311 (internal citation omitted). Therefore, the company again proposes in this case to open the LIA credit availability to all residential rate customers, to transition Rate D1.6 customers to Rate D1.11, and retire Rate D1.6 at the end of the projected test year.

The Staff supports the company's request to retire Rate D1.6 and make the LIA credit available to all residential rates. The Staff states that "[i]f the Commission does not approve the

Company's proposal to make the LIA credit available on all residential rate schedules, then those customers would not be able to take advantage of lower-cost off-peak rates." 6 Tr 4900; *see also*, Staff's initial brief, p. 124.

The DAAOs argue that the company's impact study "fell short of the Commission's order by failing to provide an analysis of shutoff information, failing to analyze the factors impacting household ability to shift usage, and failing to conduct any regression analysis." DAAOs' initial brief, p. 69; *see also*, DAAOs' reply brief, p. 21. The DAAOs assert that Rate D1.11 will likely be more expensive for low-income customers, and they request that the Commission deny DTE Electric's request to retire Rate D1.6 until the company provides a more sufficient study of the transition to a default TOU rate.

The CEOs agree with the DAAOs, stating that if the Commission approves the company's request, then:

> it should also order the Company to study and adopt mitigation measures aimed at reducing the bill impacts for the roughly one-third of low-income customers that would be worse off under the new rate. This should include expanded outreach to low-income customers focused on "educating them about opportunities to save money and providing them with tools – such as low-income energy efficiency programs, weatherization, and technology like smart thermostats – to further reduce their bills without compromising comfort or safety." Further, the Commission should direct DTE to develop "a plan to use smart meter data to identify and address customers who engage in energy-limiting behavior that is averse [sic] to health and safety."

CEOs' initial brief, p. 18 (quoting 6 Tr 3230); *see also*, CEOs' reply brief, pp. 6-7.

DTE Electric disagrees with the DAAOs' and the CEOs' request to delay the retirement of Rate D1.6 and the transition to Rate D1.11 and to require the company to perform a more comprehensive and collaborative study. The company asserts that "there is no obvious end point to the analysis proposed by [the DAAOs'] witness Koeppel[,] and the Commission approved the transition of almost two million customers from D1 to D1.11 without the type of data sought by witness Koeppel. CEO witness Kenworthy also agreed that low-income customers are generally better off under a TOU rate." DTE Electric's initial brief, p. 311 (internal citation omitted); *see also*, DTE Electric's reply brief, pp. 123-124. The Staff agrees with the company. *See*, Staff's reply brief, p. 10.

The Staff notes that according to the DAAOs' testimony, it appears that the DAAOs believe that retirement of Rate D1.6 would deprive low-income customers of the $40 LIA credit. To the contrary, the Staff asserts that:

> [t]he LIA credit is currently contingent on service under Rate D1.6 but making it available to all other rates would remove that contingency *without removing the actual $40 per month credit for enrolled customers*. Staff witness Isakson pointed this out in rebuttal because it is imperative that the Commission understand that it is not necessary for the LIA credit to be tied to one specific rate.

Staff's initial brief, p. 121 (emphasis in original).

In response to the DAAOs' claim that DTE Electric's impact study was deficient and failed to include a regression analysis, the Staff states that the company's:

> analysis provides a better look at how customers' bills would be impacted because it provides *the actual impact on virtually all affected customers*, without the need for regression modelling. In other words, one does not need to find *statistically significant* differences on the bill when the Company provided *actual* differences on bills. Staff notes here that the Company['s] analysis did not include any measure of assumed load shifting by customers on TOU rates. This means that not only were 58% of customers better off on the TOU rate but the 42% that were not better off likely still have an opportunity to shift usage to the off-peak period and lower their bill.

Id., p. 123 (emphasis in original). The Staff contends that transitioning customers from Rate D1.6 to Rate D1.11 would reduce utility bills for more than half of low-income customers and would provide the opportunity to reduce the utility bills for the remainder.

The Commission finds that DTE Electric's proposal to retire Rate Schedule D1.6, to transition customers to Rate Schedule D1.11, and to extend the LIA credit to all residential base rates should be approved. The Commission finds persuasive the company's, the Staff's, and the CEOs' arguments that nearly two-thirds of low-income customers would experience reduced utility rates. *See*, DTE Electric's initial brief, pp. 310-311; Staff's initial brief, p. 123; CEOs' initial brief, p. 18. However, the Commission finds that DTE Electric did not sufficiently perform the impact study ordered in the December 1 order. Therefore, in its next general rate case, DTE Electric shall include, in relation to the transition from Rate Schedule D1.6 to Rate Schedule D1.11, an analysis of shutoff information, an analysis of the factors impacting household ability to shift usage, and regression analyses. For the remaining one-third of customers who may experience higher utility rates as a result of the transition, the Commission finds that the company shall implement the CEOs' recommended mitigation measures: expanded educational outreach to low-income customers regarding low-income energy efficiency programs, weatherization, and smart thermostats; and the use of smart meter data to identify customers and address energy-limiting behavior that is adverse to health and safety. *See*, CEOs' initial brief, p. 18.

2. Energy Assistance Programs

a. Low-income Assistance Credit

DTE Electric notes that the LIA credit provides a $40 monthly bill credit to customers whose total household income is at or below 150% of the FPL. According to the company, "[o]ver 38,000 unique households receive the electric LIA credit with an annual monthly average of 32,125 [households]." 6 Tr 2371. DTE Electric explains that there are several ways in which customers receive an LIA credit:

> 1. Customers who become enrolled in the LSP [Low-income Self-Sufficiency Program] program [sic] are also enrolled to receive the LIA credit.
>
> 2. Graduates of LSP may continue to receive the LIA credit if maintaining their low-income eligibility status.

3. At the Company's discretion, customers receiving the RIA [residential income assistance] credit can transition to LIA when there is availability.

> Aligning the LIA credit with LSP helps our most vulnerable customers move toward self-sufficiency. Though non-LSP customers may also receive the LIA credit, experience has shown that applying the low-income credit first towards a long-term program yields the highest self-sufficiency and assists in preventing missed payments.

6 Tr 2372. The company contends that the LIA credit is not as effective if it is applied randomly rather than paired with the LSP.

DTE Electric proposes to increase the LIA credit from $40 to $50. The company asserts that:

> [a]t the time of implementation, the LIA credit represented an approximate 43% credit to an eligible low income customer's bill compared to what the bill would have been without the credit. Based on the current Rate Schedule D1.6 rates approved by the Commission in Case No. U-21297, the current $40 LIA credit represents an approximate 34% credit to a low income customer's bill. The proposal to raise the credit to $50 aims to align the financial support provided to low-income customers receiving LIA with the originally approved credit offset as a percentage of their bills. The adjustment seeks to ensure that the credit amount is more in line with the intended assistance for customers facing financial challenges, providing a more consistent and impactful measure of relief.

6 Tr 2373; *see also*, DTE Electric's initial brief, p. 310.

Responding to the company's proposal, the Staff states that:

> Michigan's most vulnerable customers would benefit from additional assistance, but [Staff is] not persuaded that Company witness Sparks provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes. As indicated by the cited orders, this collaborative RIA/LIA reform work is being performed in the EAAC [Energy Affordability and Accessibility Collaborative] workgroups. Staff's position is that collaborative discussions with interested/invested parties as well as all investor-owned utilities will lead to the most informed positions and decisions on this matter.

6 Tr 3525-3526. Accordingly, the Staff recommends that because the EAAC is working to reform the RIA and LIA credits, the Commission should not approve any changes to the structure of the credits until the EAAC completes its Commission-assigned tasks. *See*, Staff's initial brief,

pp. 177-180. In addition, the Staff states that increasing the LIA credit will contribute more money to a program that subsidizes the Michigan Energy Assistance Program (MEAP) and "could cause issues in disentangling the programs if the EAAC or the Commission so recommend and could change outcomes or timelines for implementing changes to such programs." *Id*., pp. 180-181.

However, the Staff requests that the Commission update the language of the LIA "to reflect the LIA language more recently approved for other regulated utilities as well as the prudency to have the LIA tariff reflect the eligibility requirements outlined in MCL 460.10(t) and the realities of how DTE determines eligibility for the program." Staff's initial brief, pp. 128-129. The Staff states that no party contested the proposed language and recommends that the Commission approve the proposed changes.

MNSC highlights the hardships faced by a number of DTE Electric customers and the difficulty to afford utility bills and other necessities. *See*, MNSC's initial brief, pp. 160-164. MNSC recommends that DTE Electric "should transition from offering a flat LIA credit to eligible households at all income levels to a tiered program that increases the LIA credit amount for households with lower incomes so that bill burdens are meaningfully reduced." *Id*., p. 162; *see also*, *id*., pp. 168, 170-171. In addition, MNSC asserts that the company should remove the LIA program participation cap and allow all eligible customers to participate. *See*, *id*., p. 172. To make it simpler for customers to demonstrate eligibility, MNSC asserts that the company should permit customers to self-attest that they are enrolled in the federal Supplemental Nutrition Assistance Program and, thus, should be enrolled in the LIA program. *See*, 6 Tr 3862; MNSC's initial brief, p. 171.

Regarding the LSP, MNSC states that DTE Electric "should allow LSP participants the opportunity to obtain complete forgiveness of total pre-program arrears, provide arrearage forgiveness credits on a pro rata basis for each complete bill payment made over 24 months, and provide retroactive credits when a previously missed payment is made." MNSC's initial brief, p. 162; *see also*, *id*., p. 172. Furthermore, MNSC contends that the company should tier its LSP arrearage forgiveness benefits by allowing households with incomes at or below 150% of the FPL to earn forgiveness in 12 months instead of 24.

The DAAOs assert DTE Electric's rates continue to rise and that an increased number of customers report that they have not be able to afford energy expenses since 2021. The DAAOs contend that the affordability crisis disproportionately affects low-income customers and Black, Indigenous, and people of color (BIPOC) communities and causes continuing and substantial harm to communities. The DAAOs argue that DTE Electric has failed to develop a plan to address the affordability crisis. *See*, DAAOs' initial brief, pp. 10-14. Accordingly, the DAAOs request that the Commission should:

> (1) require DTE to track the affordability gap and provide an affordability analysis in future rate cases, (2) require DTE to put forward a proposal for a universal Percentage of Income Payment Plan [(PIPP)] with total energy burdens set at a maximum of 6% of income, and (3) require DTE to provide a proposal to invest in low-income communities as a cost-effective way to address the affordability crisis.

Id., p. 14. The CEOs agree. *See*, CEOs' initial brief, pp. 29-30.

The DAAOs assert that there are few options to assist low-income customers in paying their monthly utility bills and those that are available are difficult to locate, access, and navigate. *See*, DAAOs' initial brief, pp. 16-29. The DAAOs state that the Commission should require DTE Electric to implement a PIPP that:

> would cap a residential low-income customer's energy costs (both gas and electric) at 6% of their total income, which would result in a 3% bill cap for electric-only

> customers and a 6% bill cap for customers who use electricity for heating as well. For any electricity costs that exceed the aforementioned bill cap, DTE Electric would provide a credit in the amount accrued in excess of the customer's cap.

Id., p. 30 (footnotes omitted). The DAAOs contend that a PIPP is financially feasible for DTE Electric and that the program has proven to be successful in other states. *See*, *id*., pp. 30-33.

In addition, the DAAOs assert that "[i]nvestments in LMI [low- and moderate-income] weatherization, efficiency, electrification, community solar, and DR can provide long-term reductions in energy cost burdens for the neediest households while simultaneously reducing greenhouse gas emissions and bringing health co-benefits." 6 Tr 4549; *see also*, DAAOs' initial brief, pp. 33-38. The DAAOs state that:

> [c]ommunity solar programs, in particular, can provide direct benefits to low-income households by offering bill credits or reduced rates to participants. "The U.S. Department of Energy aims to increase the percentage bill savings from 10 percent to 20 percent [in community solar programs], and a low-income community solar pilot in Illinois guarantees bill savings of 50 percent for low-income customers." Investing in community solar enables a more inclusive transition to renewable energy, allowing renters and those unable to install rooftop solar to participate and benefit from clean energy and addressing the disproportionate participation in distributed generation by higher-income households. Additionally, community solar paired with storage in low-income communities can enhance grid resilience by distributing energy generation closer to demand, thereby reducing outages and costs for populations disproportionately impacted by the loss of power.

DAAOs' initial brief, p. 37 (quoting 6 Tr 4555). In the DAAOs' opinion, implementing these investments will also be financially beneficial for DTE Electric because it will reduce arrearages and shutoffs and the need for short-term utility bill assistance.

The DAAOs also assert that the Commission is not timely addressing affordability challenges. According to the DAAOs:

> Staff argues that the EAAC's AAA [Affordability, Alignment, and Assistance] subcommittee and Staff are already working on a recommendation, and, therefore, the Commission should continue to delay action on affordability until the EAAC issues its recommendation. However, the Commission should not leave this task to

> the EAAC and its AAA subcommittee. While some of the work of the EAAC and AAA has been constructive, the groups have failed to make measurable progress on the issue of energy affordability and do not act with the urgency required by the affordability crisis.

Id., p. 39 (footnotes omitted). Moreover, the DAAOs contend that the EAAC and AAA have not effectively engaged with communities affected by affordability issues and, therefore, do not fully understand the issues affecting vulnerable communities. The DAAOs request that the Commission take immediate action to address affordability issues, as recommended by the DAAOs.

Furthermore, the DAAOs assert that "the Commission should consider non-energy benefits when assessing the impacts of unaffordable and unreliable energy and the benefits of proposals to address unaffordability and poor reliability." DAAOs' initial brief, p. 43. The DAAOs note that non-energy benefits include the cost reductions related to affordability and reliability, such as reduced shelter and healthcare costs for persons displaced due to the inability to pay utility bills. The DAAOs state that "[i]ncorporating non-energy benefits into utility regulatory proceedings helps capture the full impact of ratemaking and energy policies on individuals and society. Including non-energy benefits allows the Commission to assess the societal value of investments in energy efficiency, renewable energy, and affordability measures when considering their costs." *Id*., p. 46.

In response to the Staff, DTE Electric continues to argue that the LIA credit should be increased to $50, explaining that the increase "is designed to align the financial support provided to low-income customers receiving LIA with the originally-approved credit offset as a percentage of their bills. The Company does not propose to change the LIA credit's structure, nor change potential EAAC outcomes." DTE Electric's initial brief, p. 312.

Regarding MNSC's request that the company provide a self-attestation form, the Staff believes that DTE Electric has already offered a self-attestation form, but it was not included in the company's tariff language. The Staff states that it "adopted and expanded upon that proposal in rebuttal testimony and proposed [that] language be added to both the RIA and LIA tariffs regardless of decisions made regarding rate schedule D1.6 . . . ." Staff's initial brief, pp. 129-130. According to the Staff, the proposed language regarding the self-attestation form is uncontested and should be approved.

In response to the DAAOs requests that DTE Electric provide a universal affordability program for all residential customers and a unified affordability program that caps customers rates at 6% of income, the Staff contends that these proposals conflict with the directives in MCL 460.11(1) and MCL 460.10(t) and should be denied. *See*, Staff's initial brief, pp. 181-182. In addition, the Staff states that "the logistical challenges of verifying income for all residential customers would require a significant amount of trust between utilities and customers to collect sensitive information, customers may not even respond to income queries, and utility staffing costs to verify income annually could be prohibitively expensive, which could further increase rates." *Id*., p. 182.

The Staff also disagrees with the DAAOs' recommendations regarding the PIPP. In the Staff's opinion, "the evaluation of cost and effectiveness of the PIPP pilots is the current charge of the Commission's Affordability, Alignment, and Assistance Subcommittee in the Commission's Energy Affordability and Accessibility Collaborative," and a PIPP should not be approved until the EAAC completes its analysis and issues a recommendation. Staff's initial brief, p. 182.

Further, the Staff objects to the DAAOs' request that the Commission approve a 0.743 cent per kWh surcharge for all customers to close the energy affordability gap and an 0.18 cent per kWh surcharge to fund $10 million in energy assistance, based on a proposed $90 million in projected funding for the PIPP. The Staff states that it "could not find a calculation explaining how the witness calculated $90 million in available funding but notes that [DAAO] witness Kinkhabwala likely included some funding from federal Low-Income Home Energy Assistance Program (LIHEAP) and [MEAP]." Staff's initial brief, p. 183. In addition, the Staff contends that the DAAOs failed to clearly explain how the surcharge would be assessed on all customers "given DAAO's other proposals to limit all residential customer bills to six percent of income," and it would likely lead to revenue shortfalls in the assistance fund as well as in base rates. *Id*.

The Staff disagrees with the DAAOs' claim that community solar can provide up to 20% savings on customers' utility bills. The Staff states that "no Michigan costs or current compensation amounts were used to determine whether that projected amount of savings is appropriate." Staff's initial brief, p. 134. The Staff contends that community solar savings cannot be promised or guaranteed.

In response to the DAAOs' recommendation that the Commission consider non-energy benefits, the Staff states that:

> [m]any non-energy benefits lack standardized measurement methodologies. For example, assigning a monetary value to improved health outcomes or the benefits of remaining in one's home can be highly subjective and vary significantly depending on the methodology used. In addition, this complexity and the inherent uncertainty can lead to variable and subjective estimates that may not be reliable.

6 Tr 5217; *see also*, Staff's initial brief, pp. 158-161. The Staff avers that although non-energy benefits may be important to understanding the impact of utility bills on aspects of a customer's life, there are methodological and regulatory challenges to including non-energy benefits in ratemaking that outweigh the purported benefits. Thus, the Staff "recommends that the bill

savings be determined by setting the appropriate, cost-based, compensation and the actual costs to install the community solar systems." Staff's reply brief, p. 16.

In response to the Staff's recommendation that any modification to DTE Electric's LIA program should be decided by the EAAC and its AAA subcommittee, MNSC states that "[t]he Commission can and should act to improve DTE's low-income programs now, before rates rise again and even more customers find themselves struggling to pay their electricity bills." MNSC's initial brief, p. 173. MNSC contends that it is unreasonable for the Commission to wait for a report from the EAAC to provide assistance to vulnerable customers—such issues should be decided in a rate case. MNSC contends that, although better alternatives exist and the LIA could be improved, the Commission should approve the company's proposed $10 increase to the LIA credit.

The Staff disagrees with MNSC, asserting that "the Commission directed the subcommittee to investigate and evaluate this issue, yet the arguments in support of an immediate credit increase are, simply put, a rush to judgment and a recommendation to dustbin the work of the subcommittee, which, again, is undertaking this work at the direction of the Commission." Staff's reply brief, p. 20. The Staff maintains that the collaborative discussions of the EAAC and AAA will provide the most informed, comprehensive recommendation for this issue and there is no evidence that the remainder of the process will take an unreasonable amount of time.

In response to the DAAOs' claim that it is difficult for customers to determine eligibility for and to navigate DTE Electric's low-income programs, the Staff states that its:

> proposed LIA tariff language partially clears up this confusion in which the proposed LIA tariff language states that the RIA and LIA credits cannot be taken together and that the eligibility criteria is in line with the RIA eligibility along with the Company's affordable payment plan. (Staff's Initial Brief, p 129.) The language, however, does not explicitly clarify which customers will receive the

> credit, and Staff cannot find a reference from past cases that gave the Company the authority to select which customers received the LIA credit.
>
> The currently-approved tariff language on the Eighth Revised Sheet No. D12.01 of the DTE Electric tariff book simply states that "Customers who select this pilot rate must qualify for the Residential Service rate," which gives the impression that customers can request or choose to be on the rate schedule. A corresponding issue was raised by Staff in DTE Electric rate [C]ase No. U-20836, in which Staff proposed to not allow the Company to have discretion to give the credit to whomever it chose. (MPSC Case No. U-20836 11/18/2022 Order, p 403.) The Commission order disagreed with Staff's proposal, and the Commission directed analysis of the LIA program cap and enrollment assignment to the EAAC. (MPSC Case No. U-20836, 11/18/2022 Order, p 407.) This is part of the current analysis being performed by the EAAC's AAA subcommittee that Staff referenced in its direct and rebuttal testimony.

Staff's reply brief, pp. 25-26.

Furthermore, in response to the DAAOs' recommendations to the Commission regarding non-energy benefits, the Staff asserts that the DAAOs' "proposal is vague and does not allow for reasonable analysis of how considering non energy benefits would be accomplished and what impact it would have on the rate-setting process." Staff's reply brief, p. 44. The Staff also disputes the DAAOs' claim that other public utility commissions consider non-energy benefits, stating that the claim is vague and could not be verified.

The DAAOs disagree with the Staff that the PIPP conflicts with the requirements of MCL 460.11(1). The DAAOs explain that:

> [o]ne of the exceptions "provided in this subsection" grants the Commission the power to "establish eligible low-income customer or eligible senior citizen customer rates." MCL 460.10(t) defines an eligible low-income customer as one "whose household income does not exceed 150% of the poverty level" or who receives "[a]ssistance from a state emergency relief program," "[f]ood stamps," or "Medicaid." Read in its entirety, MCL 460.11 allows the Commission to establish lower electric rates for eligible low-income customers that are not equal to the cost of providing service to the class.

DAAOs' reply brief, p. 5 (footnotes omitted). In addition, the DAAOs object to the Staff's claim that the PIPP would conflict with the requirements of MCL 460.11(2) and MCL 460.10(t), asserting that the Staff's rationale is unclear. Moreover, the DAAOs disagree with the Staff's argument that the proposed surcharge will not sufficiently fund the PIPP, stating that the DAAOs provided an extensive explanation of the program in their testimony and initial brief.

The DAAOs also reiterate that the Commission should not wait for a report from the EAAC or AAA to address affordability issues and should incorporate non-energy benefits into its rate-making proceedings. *See*, DAAOs' reply brief, pp. 8-14. The DAAOs state that:

> [w]hile Staff claims "there is no standard methodology for measuring non-energy benefits within the rate-making process" and that the lack of standardization would lead to "variable and subjective" estimates, Staff does not provide an explanation for why the Commission cannot impose a standard methodology or require utilities to adopt an existing societal cost test used in other [Commission] proceedings. Staff even admits that "utilities [in Michigan] have provided societal costs tests in energy efficiency proceedings as references." Given that the Commission has previously ordered utilities to propose a social cost test that could be applicable to ratemaking proceedings, there is no reason that the Commission could not do so again.

Id., p. 13 (quoting Staff's initial brief, pp. 159-160; 6 Tr 5216).

The DAAOs state that although the Staff:

> raises valid concerns about the challenges of incorporating non-energy benefits into ratemaking, the significant societal and economic impacts of nonenergy benefits, even if imperfectly quantified, warrant their inclusion in the Commission's decision-making process to ensure a more comprehensive and equitable evaluation of utility and intervenor proposals in this case and of energy policies more generally.

DAAOs' initial brief, p. 47. The DAAOs recommend that the Commission should order a comprehensive study to quantify non-energy benefits and to estimate the societal benefits of providing affordable energy. According to the DAAOs, "[r]esources should be used to track and analyze non-energy benefits over time, particularly focusing on high-burden households and the resulting social benefits, such as reduced healthcare and social service costs." *Id*., p. 49 (footnote omitted).

MNSC disputes the Staff's claim that increasing the LIA credit will make it more difficult to disentangle the LIA program and MEAP. MNSC contends that "nothing in the record supports the proposition that the LIA program subsidizes the MEAP," and the "Staff does not explain how a $10 increase in the amount of the LIA credit could cause issues that would not already exist at the current LIA credit amount, and no evidence in the record supports the conclusion that it would." MNSC's reply brief, pp. 27-28.

MNSC also objects to the Staff's recommendation that the Commission reject MNSC's proposal to adopt tiered LIA credits and to uncap the LIA program enrollment. According to MNSC, the proposals "are evidence-based methods for improving affordability . . . supported by data," and "will reduce arrears, collection costs, uncollectibles, and working capital expenses." MNSC's reply brief, p. 30.

The Commission finds persuasive DTE Electric's, MNSC's, and the DAAOs' testimony regarding the hardships faced by the company's low-income and vulnerable customers. *See*, 6 Tr 2373; DTE Electric's initial brief, p. 310; MNSC's initial brief, pp. 160-164; DAAOs' initial brief, pp. 10-12. Customers 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. Additionally, the Commission finds MNSC's testimony persuasive that a $10 increase in the LIA credit would not cause issues that would not already exist at the existing $40 credit amount. MNSC's reply brief, pp. 27-28. Therefore, the Commission finds that the LIA credit should be increased to $50. However, the Commission finds that after final decisions and recommendations are provided by the EAAC, the Commission may continue to refine the LIA program in the future, including potentially changing the amount of this credit.

The Commission also finds that the Staff's proposed tariff language for a self-attestation form and the "Special Low-income Assistance Credit" should be approved to provide better clarity regarding customer eligibility for the RIA and LIA credits. *See*, Staff's initial brief, pp. 128-130; Staff's reply brief, pp. 25-26. As noted by the Staff, no party objects to the proposed tariff revisions. However, the Commission finds that the issues of the LIA program cap, enrollment assignment, LSP amendments, and PIPP pilots shall continue to be addressed by the EAAC's AAA subcommittee.

Regarding the DAAOs' request that DTE Electric invest in community solar to produce utility bill savings, reduce arrearages, and reduce shutoffs for low-income communities, the Commission agrees with the Staff that the DAAOs' testimony on this issue was limited and the calculation failed to include Michigan-specific data. *See*, Staff's initial brief, p. 134; 6 Tr 4555. Furthermore, the Commission notes that it is unclear whether, in the absence of a statutory directive, it has the authority to authorize community solar programs other than those offered by the utilities pursuant to MCL 460.1061. However, the Commission is supportive of community solar proposals from the company that work with community organizations to address their concerns and provide the opportunity for cost-effective community solar.

In response to the DAAOs' request that the Commission consider non-energy benefits when analyzing the impacts of energy affordability and reliability, the Commission notes that as discussed in Section C.3. above, in the July 27 order, the Commission directed that the Staff work with interested persons to develop BCA requirements, i.e., an open-source BCA tool, to be used in multiple types of dockets. The Commission notes this BCA open-source tool development is occurring in Case No. U-20898 and this case provides a platform for considering issues such as non-energy benefits as they relate to energy affordability and reliability. The Commission has extended the deadline for developing an open-source BCA tool to 2026, and invites the DAAOs and any interested person to participate in this process.

b. Residential Income Assistance Credit

DTE Electric asserts that the residential income assistance (RIA) credit provides low-income customers with an $8.50 monthly bill credit, and the company forecasts a program enrollment of approximately 83,000 customers. *See*, DTE Electric's initial brief, p. 312. The company states that "[t]o be eligible, the total household income cannot exceed the 150% FPL, as verified by an authorized State or Federal agency. The credit is renewed annually based on the eligibility requirements. Customers may not receive both an electric RIA and electric LIA credit at the same time." 6 Tr 2369. According to DTE Electric, customers are automatically enrolled who receive energy assistance in the form of a Home Heating Credit (HHC), State Emergency Relief (SER), or one time assistance, and customers who are not automatically enrolled can provide documentation to qualify.

The Staff requests that the Commission reject the company's proposed RIA enrollment projection. The Staff states that "through the audit responses in Exhibit S-17.0 . . . the Company failed to provide the RIA projection calculation when requested and only vaguely stated that the projection was based on average historical enrollment percent increases, despite there being no trend or pattern in the percentage enrollment increases to support the use of that method." Staff's initial brief, p. 76, 83. The Staff provides an alternative calculation that uses a three-year historical average monthly credit disbursement, which totals $2,740,321 for 56,134 customers. The Staff explains that it:

> justified only using data provided in the Part III Attachment 5(9) filing requirement and not including 2023 enrollment data provided in Company witness Sparks' testimony because witness Sparks stated in testimony that the data were snapshots of enrollment at the end of the month instead of monthly averaged enrollment, as is

> reported in Part III Attachment 5(9). By comparing the data, it is clear the numbers are different, which has historically been an issue in DTE Gas [Company] and DTE Electric cases and indicative of a larger issue of the data consistency and accuracy at DTE. Of note, one historical DTE Electric data reporting issue occurred in [Commission] Case No. U-20836, (as summarized in the 11/18/2022 Order pp 251-255) and was thought to be resolved in [Commission] Case No[.] U-21297, indicated by Staff's lack of contention with DTE's RIA projection, but now another data inconsistency seems to be occurring. This example is not an isolated instance in which Staff has noted a lack of data reporting consistency between Part III of the filing requirements and other reports. In the [November 18 order], the Company was ordered to file a report to the [Case No.] U-20757 docket (filing U-20757-0525) detailing the LIA enrollment and use, titled DTE Energy Company's First Quarterly RIA and LIA Report for 2023. The enrollment numbers are similarly not consistent with what is reported in Part III Attachment 5(9) of the filing requirements.

Staff's initial brief, pp. 76-77 (internal citations omitted).

The Staff asserts that its RIA projection is more reasonable than the calculation offered by the company because the Staff utilized the following identifiers for RIA eligibility and automatic enrollment: (1) Michigan Department of Health and Human Services (MDHHS); (2) the Michigan Department of Treasury; or (3) MEAP grantees notifying utilities of a customer receiving a SER payment, an HHC energy draft, or a one-time assistance payment, respectively, that would get applied to their account. 6 Tr 3523; *see also*, Staff's initial brief, p. 77. The Staff states that:

> [t]hese programs all identify a customer as RIA-eligible per MCL 460.11(2) as defined in MCL 460.10(t). (*Id.*) Staff witness Braunschweig then explained that since SER and HHC are federally-funded by the Low-Income Home Energy Assistance Program (LIHEAP), enrollment in the RIA can fluctuate based on average LIHEAP funding levels—whereas MEAP is funded at $50,000,000 annually per Public Act 95 of 2013. (*Id.*)

Staff's initial brief, p. 77.

The Staff also provides a table in its initial brief that compares historical LIHEAP funding levels and monthly RIA enrollments. *See*, *id.*, p. 78. Regarding the data in the table, the Staff "clarified that the 77,107 RIA enrollment for fiscal year 2023 was from Company witness Sparks' testimony, which was based on the month-end snapshots instead of monthly averages." *Id*. The

Staff asserts that the average funding levels are the main determinants of RIA enrollment variations because LIHEAP funding levels fluctuate and MDHHS allocations impact the level of customer assistance. The Staff states that in turn, this impacts the number of RIA recipients not necessarily proportional to the LIHEAP funding level. The Staff cites "the American Rescue Plan and Inflation Reduction Act as examples of federal LIHEAP funding increasing and LIHEAP Energy Direct payments being released by MDHHS, which increased RIA enrollment from 2021 to 2022" in the table provided. Staff's initial brief, pp. 78-79 (citing 6 Tr 3534). However, the Staff states that the elevated RIA enrollment from the COVID-19 pandemic-related funding and LIHEAP will not continue into the test year. The Staff explains that "[s]ince RIA customer eligibility is re-verified annually, the higher number of recipients the Company reported in 2022 and 2023 should not be automatically rolled over into the test year, meaning RIA enrollments should slowly decrease in the absence of the elevated Covid-related funding." 6 Tr 3534 (footnote omitted).

The Staff contends that the Commission adopted the Staff's position on this issue in the March 1 order, Consumers' most recent general electric rate case, and the Commission should continue its approval of a three-year historical projection, particularly because DTE Electric failed to provide a calculation for its RIA projection. In the event the Commission adopts the company's argument that 2023 data should be included in the RIA projection, the Staff "proposes that the Commission does not adopt Sparks' projection methodology and instead just include the 2023 data into a three-year historical average for the RIA projection." Staff's initial brief, p. 79.

MNSC recommends that DTE Electric maintain its $8.50 RIA credit but shift it to higher income households. MNSC explains that "[f]irst . . . [the RIA credits] are too small to meaningfully improve affordability for households with incomes at or below 150% FPL. Second, households between 150[%] and 250% FPL or 60% of State Median Income (SMI) still have fragile incomes and are likely to experience substantial difficulties paying their utility bills and other necessary expenses." MNSC's initial brief, p. 169; *see also*, *id*., pp. 162, 171. MNSC also asserts that to make it easier for customers to demonstrate eligibility for the RIA credit, the company should enroll customers who already participate in another public assistance program.

DTE Electric disputes the Staff's claim that the company's RIA counts are inaccurate. The company contends that:

> to clarify, 2023 RIA counts were not included in Part III. Staff's concern about the accuracy of the 2023 RIA counts presented in [the company's] direct testimony, due to differences between the data in [the company's] direct testimony versus Part III Attachment 5(9), is unwarranted. For 2020 the overall annual average between the two sources remains quite close: 39,867 in [the company's] direct testimony versus 39,668 using Part III. In 2021 and 2022 the differences are immaterial: the largest monthly difference between [the company's] direct testimony and Part III was only eight customers, with the overall annual average difference being just three customers in 2022 and five customers in 2021. Therefore, excluding 2023 based on the differences between [the company's] direct testimony and historical Part III reporting is unwarranted, given the minimal discrepancies observed in the previous years.

6 Tr 2386-2387; *see also*, DTE Electric's initial brief, p. 313. DTE Electric also disagrees with the Staff that customers will not re-enroll in the RIA program. According to the company, "[w]hile it is true that some households will not reapply to receive the RIA credit, the majority will remain recipients due to auto enrollment by other energy assistance programs as well as self-attestation." 6 Tr 2389.

Furthermore, DTE Electric objects to the Staff's recommendation to adopt the Commission's decision in the March 1 order regarding the RIA projection. The company asserts that the decision in the March 1 order is not relevant to DTE Electric's RIA forecast because different data was used for each utility's projection and Consumers did not have a tracker or deferred accounting to avoid over-projections of RIA credits. Rather, the company states that it "has a tracker in place to correct any over or under projection of enrollments." 6 Tr 2389.

In response to DTE Electric's claim that the difference between the data reported in testimony and the data reported in Part III Attachment 5(9) is immaterial, the Staff asserts that "the issue of DTE reporting several different numbers for the same data in the same timeframe is not an isolated issue and should not be acceptable. DTE has demonstrated over the years through its data reporting that this data reporting inconsistency is indicative of a larger issue." Staff's initial brief, p. 80. The Staff notes that when the company was provided an opportunity to submit accurate data in an audit request, DTE Electric continued to fail to provide data consistent with its Part III filing requirement methods. The Staff contends that the Commission should not accept the company's projection because it is unexplained and unsupported and "it undermines the ability for the Commission Staff and other parties to properly audit Company spending." *Id*.

The Staff also argues that the company failed to support its claim that the majority of RIA recipients will remain in the program through auto-enrollment and self-attestation. The Staff cites the DAAOs' testimony "as supporting evidence to the difficulties customers face with applying for assistance, including customer service representatives not promoting energy assistance when customers inquire." *Id*., p. 81 (citing 6 Tr 4637-4638, 4678, 4683, 4688). In addition, the Staff notes that MEAP and LIHEAP funding is capped, limiting the number of customers who may automatically enroll in the RIA program annually. In the Staff's opinion, for the majority of RIA customers to remain in the program through auto-enrollment, "LIHEAP and MEAP funding would have to increase annually, instead of staying the same or decrease, as is the current reality." Staff's initial brief, p. 82.

Regarding DTE Electric's claim that it has a tracker to avoid under- and over-projections of RIA enrollments, the Staff argues that "it is important to approve the most accurate RIA projection and not rely on the tracker, since customers would be paying for inflated RIA projections in the short-term, while waiting for the deferred accounting to normalize the inaccurate projection in future. Indeed, inaccurate projections could create generational inequities in ratemaking." *Id*., p. 83.

The Staff objects to MNSC's request to redirect RIA credits to customers with special needs up to 250% of the FPL or 60% of the SMI, "making public assistance a qualifier for RIA, transferring RIA customers to become LIA customers, putting those new LIA customers on a newly structured tiered credit, uncapping enrollment for both credits, and reconciling costs on an annual basis." Staff's initial brief, p. 184; *see also*, *id*., pp. 185-186. The Staff reiterates that these issues are being considered by the EAAC's AAA subcommittee and that the Commission should defer decisions on these issues until the conclusion of the subcommittee's work. In addition, the Staff contends that MNSC's proposal to raise the income eligibility on the RIA credit conflicts with MCL 460.11(2) and MCL 460.10t.

Responding to the Staff, MNSC states that:

> [w]hile MCL 460.11 and 460.10t may preclude full implementation [of MNSC]'s recommendation at this time, [MNSC]'s analysis and reasons for extending support to higher income families are sound. MNSC urge the Commission to consider ways to address the needs of households with incomes between 150[%] and 250% FPL or 60% SMI, including supporting legislative changes that would expand the definition of eligible low-income customers or authorize the Commission to establish special rates for this population.

MNSC's initial brief, pp. 169-170.

The Commission finds that the Staff's alternate calculation using a three-year historical projection that is updated to include 2023 data should be approved. As noted by the Staff, when asked to provide the calculation for the company's RIA projection, DTE Electric states it:

> used a 2 year historical average rate of change. Applying that average to the 2023 monthly average of enrollments results in a forecast of 87,000 per month. We also calculated a slight 6% decline in 2023 of accounts receiving energy assistance and included that as part of the forecast since energy assistance triggers accounts to receive the RIA credit. Using that 6% decline brings it to an estimated 83,000 monthly projection.

Exhibit S-17, p. 1. The Staff acknowledges that in calculating its three-year historical average, it "only [used] data provided in the Part III Attachment 5(9) filing requirement and [did] not includ[e] 2023 enrollment data provided in Company witness Sparks' testimony." Staff's initial brief, p. 76. The Commission agrees with DTE Electric that 2023 data should be included. A closer look at the data, however, suggests that RIA enrollment peaked at the end of 2022 and beginning of 2023, with monthly average RIA enrollment generally declining over 2023. *See*, Exhibit S-17.1. As such, the Commission is not convinced that DTE Electric's approach of using a two-year average rate of change, applying that average rate to the 2023 monthly average of enrollments, and making a downward adjustment of 6% to account for a decline in accounts receiving energy assistance is reasonable. Rather, the Commission finds that the Staff's methodology using a three-year average, but including 2023 data, is likely to result in a more accurate projection. Accordingly, using the calendar year monthly averages of 56,908 for 2021, 71,826 for 2022, and 75,522 for 2023, the Commission calculates a three-year historical average enrollment of 68,085. *See*, Exhibit S-17-1. This results in a total cost for the RIA program of $6,944,670, a reduction of $1,521,330 from the company's projection.

In addition, the Commission shares the Staff's concerns regarding the quality, consistency, and accuracy of data provided by both DTE Electric and DTE Gas relating to the RIA credit, which has been an ongoing issue, including as recently as two years ago in Case No. U-20836. In future cases, the Commission will continue to examine the data provided by DTE Electric closely, both in direct testimony and in its annual reports, and encourages the company to continue to ensure accuracy in the numbers it reports to the Commission and to continue to refine its data management practices.

Finally, the Commission respectfully declines to adopt MNSC's recommendation to shift the RIA credit to customers above 150% of the FPL. Even while arguing that the "reasons for extending support to higher income families are sound," MNSC concedes that "MCL 460.11 and 460.10t may preclude full implementation [of its] recommendation at this time." MNSC's initial brief, p. 135.

c. Residential Senior Credit

The Staff states that DTE Electric failed to provide a residential senior credit (RSC) customer count projection but included recovery of $5.315 million for 104,224 monthly RSC credit disbursements in the company's Schedule F-3 rate design file. 6 Tr 3535; *see also*, Staff's initial brief, p. 83. The Staff asserts that DTE Electric's proposed RSC should be rejected, and the Staff provides an alternative calculation: a three-year historical average of the actual RSC credit disbursements totaling 94,525 monthly disbursements for a revenue increase of $494,656. The Staff explains that "credit disbursement amounts have been relatively stable for the 3 historical years provided by the Company in Attachment 5(9) of its Part III filing requirements. Absent significant interest in or outreach to enroll customers in the credit, there is no evidence on the record that this program would experience a significant increase in enrollment." 6 Tr 3536; *see also*, Staff's initial brief, p. 84.

DTE Electric disputes the Staff's proposed RSC calculation, asserting that although the company inadvertently made an error in its initial forecast, the company's forecast methodology is correct. DTE Electric explains that it:

> originally proposed 104,224, which reflects a trendline from Staff's historical years, and included 2023 data to date when that number was finalized. Full 2023 actual credits averaged 109,754 monthly. To-date 2024 credits are averaging 125,141 monthly. The Company also made an error in its initially-filed forecast, which undercounted the forecast by 19,849. Therefore, the Company's initially-proposed 104,224 is reasonable, and likely under-forecast. Moreover, the senior credit is not tracked or reconciled, so an under-forecast is not recoverable. Therefore, the Commission should update the Company's initial forecast of 104,224 to include the 19,849 credit counts that were inadvertently excluded from the Company's initial filing, for a total of 124,073.

DTE Electric's initial brief, p. 313 (internal citations omitted).

In response, the Staff contends that DTE Electric's "use of a trend-line to project a credit that has been historically relatively stable assumes that an increase in enrollment will continue in future. There is, however, no evidence on the record to indicate that increase will continue, and the MDHHS data depicted above indicates the opposite." Staff's initial brief, p. 85. Additionally, because of data reliability issues, the Staff believes that it is more prudent to use the data provided in the filing requirements for these credits because it seems to be more accurate and audited by the company compared to the data reported elsewhere.

Regarding DTE Electric's claim that the RSC is not tracked or reconciled and that a substantial under-forecast is not recoverable in the future, the Staff "reminds the Commission that the opposite is also true; over-projections in customer counts are retained by the Company and not credited toward customer bills." *Id.*, p. 86.

DTE Electric responds to the Staff:

> emphasizing [that] the numbers quoted from [DTE Electric witness] Mr. Willis' testimony are based on historical actuals and already reflect a level supportive of the 124,073 customers that Mr. Willis recommends. Thus, contrary to Staff's claim

> that the Company's RSC projection is significantly inflated, the evidentiary record supports adoption of the Company's projection which is based on 2023 and 2024 actual data.

DTE Electric's reply brief, p. 127 (citing 6 Tr 2619).

The Commission finds persuasive the company's proposed calculation of the RSC. While the Staff argues that DTE Electric used a trend line to project the RSC customer count and assumed an increase in enrollment, testimony offered by the company shows that "2023 actual credits averaged 109,754 monthly disbursements [and] 2024 credits to-date are averaging 125,141 monthly disbursements." 6 Tr 2619; *see also*, 6 Tr 3536. Although the Commission acknowledges the Staff's arguments that the company's historical RSC disbursements have been relatively stable for the last three years and that, pursuant to information provided by MDHHS, "the percentage of Michigan residents 65 years of age and older has hardly changed over the past 3 years— especially not enough to warrant the 8.5% increase in the senior credit that the Company is requesting," the Commission ultimately finds DTE Electric's reliance on actual enrollment numbers for the RSC to be more compelling. 6 Tr 3536-3537. However, given the issues with data accuracy in this case and that DTE Electric did not update its projections until its rebuttal testimony, the Commission is not convinced to "update the Company's initial senior credit customer forecast of 104,224 to include the 19,849 credit counts inadvertently excluded from the Company's initial filing, for a total of 124,073." 6 Tr 2619. Therefore, the Commission adopts DTE Electric's RSC customer forecast of 104,224.

E. Commercial Secondary Rate Design Proposals

1. Rate Schedule D3.11, Commercial Secondary Time of Use

As part of the December 1 order, the Commission ordered that the company "develop and present optional time-of-use rates for its commercial secondary and primary customers." DTE

Electric's initial brief, p. 314 (citing December 1 order, p. 372). Thus, in this case, DTE Electric proposes Rate Schedule D3.11. *Id.*; *see also*, 6 Tr 2599; Exhibit A-16, Schedule F3 Revised, and Schedule F8. DTE Electric also proposes Rate Schedule D14 "as an optional time-of-use rate for primary customers." DTE Electric's initial brief, p. 314; *see also*, 6 Tr 2609; Exhibit A-16, Schedule F3 Revised, and Schedule F8.

DTE Electric's witness, Mr. Willis, explains that the proposed Rate Schedule D3.11 would vary depending on the season and time of day, consistent with DTE Electric's default residential rate schedule. 6 Tr 2601. Summer pricing would be in effect from June to September, and on-peak pricing would be from 1:00 p.m. to 5:00 p.m., Monday through Friday. *See*, 6 Tr 2601. The on-peak period "aligns with both the system coincident peaks during the summer months as well as the secondary class peaks in the summer months." 6 Tr 2601. Mr. Willis explained that the pricing determinants between peak periods and seasons is based on historic D3 actuals and assumed shifts peaks, with the shifts reflecting expected customer behavior changes which may include non-energy benefits usage changes for customers choosing the D3.11 rate. 6 Tr 2602.

Mr. Willis testifies that Rate Schedule D3.11 "is designed to be revenue neutral to Rate Schedule D3 until there is sufficient historical usage to determine the utility of, and potentially implement, a separate revenue line in the D3/Other cost of service class, or a separate cost of service class." 6 Tr 2600. Mr. Willis explained that Rate Schedule D3.11 uses "the same overall billing determinants, cost allocations, and underlying revenue requirements as D3 in this case, similar to the initial D1.11 proposal in Case No. U-20836." 6 Tr 2600. Mr. Willis stated that the accompanying proposed tariff required that customers choosing to use D3.11 would need to stay on the rate "for at least 12-months before switching to another rate" and that the proposed tariff had an enrollment of only 1,000 customers. 6 Tr 2600. Mr. Willis explained that D3.11 "would need to be developed, tested, and implemented" into DTE Electric's billing system after the company received approval for the rate. 6 Tr 2603. Mr. Willis further testifies that DTE Electric plans on having the rate available by December 31, 2025. 6 Tr 2603.

In its reply brief, DTE Electric explains that Rate Schedule D3.11 is designed to be "revenue neutral to Rate Schedule D3 if all D3 customers were instead to take service on Rate Schedule D3.11" with all customers having a choice "between a subset of rates." DTE Electric's reply brief, p. 130. In fact, DTE Electric's witness, Mr. Willis, had testifies that "[t]o the extent an existing D4 customer could benefit by switching to the [c]ompany's proposed D3.11, they would be able to do so." *Id.*, p. 131. Mr. Willis contended that DTE Electric's proposed time of use (TOU) rate is "conceptually sound and offers options for all C&I customers" such that MEIU's proposal as described below would be inappropriate because it would potentially result in underrecovery. *Id.*; 6 Tr 2634, 2638. DTE Electric also highlights various reasons why it disagrees with MEIU and GLREA's arguments, stating that the basic rate structure has yet to be approved and no customers are presently enrolled in D3.11, thus, "[i]t would be exceptionally premature to begin any discussion of requiring these rates" such that, as GLREA concedes, discussion "should wait for a future rate case." DTE Electric's reply brief, p. 136 (citing GLREA's initial brief, p. 11).

MEIU's witness, Mr. Barnes, testifies about Rate D3.11. Mr. Barnes described rate D3.11 as a rate for those who take "service at secondary voltage" with the rate "mapped to achieve revenue neutrality with Schedule D3." MEIU's initial brief, p. 46; 6 Tr 4137. Mr. Barnes noted that DTE Electric's intention to make D3.11 available by December 31, 2025 is "a delay of roughly 11 months" and that by modifying the billing determinants, DTE Electric will be "increasing rates across all pricing periods because [the new rate] decreases the amount of electricity assumed to be purchased at higher rates during the on-peak price periods." MEIU's initial brief, p. 46, 56; 6 Tr 4138.

Mr. Barnes noted four shortcomings in DTE Electric's proposed D3.11 rate. The first is that DTE Electric proposes an enrollment cap of 1,000 customers with no set time limit for expiration. MEIU's initial brief, p. 52; 6 Tr 4145-4146; *see also*, Exhibit MEIU-23. By capping enrollment, MEIU argue, DTE Electric threatens to deprive its "customers of the ability to take advantage of the rates to reduce their own bill as well [as] reduce rate class or system-wide costs in a manner that benefits other ratepayers." 6 Tr 4147. Mr. Barnes also felt that DTE Electric's concern about underrecovery is speculative. Mr. Barnes stated that DTE Electric "has already proposed to adjust the billing determinants for proposed Rate Schedule D3.11 to assume a certain amount of load-shifting from on-peak to off-peak time periods" which increases its expected revenue relative to customer billings. 6 Tr 4147-4148. Lastly, the possibility of lower revenue alone is not an indicator of cost underrecovery or unreasonable cost-shifting to other customers as a TOU rate "is intended to produce load shifting away from peak periods" which should result in cost savings to offset revenue loss. MEIU's initial brief, p. 53; 6 Tr 4148. Mr. Barnes noted that previously, customers were overpaying with the "otherwise applicable non-TOU rate relative to the costs they caused" such that shifting costs to other ratepayers is justified and the rate TOU structure would be "more closely aligned with cost causation." MEIU's initial brief, p. 53; 6 Tr 4148. Mr. Barnes pointed to previous enrollment caps, stating that their "only outcomes . . . were negative" because they caused interested customers to become waitlisted and delayed enrollment such that the "ultimate outcome . . . was exactly the same as it would have been if the rate had not featured an availability cap in the first place." 6 Tr 4149. As such, Mr. Barnes stated that DTE Electric's proposed enrollment caps on Rate Schedule 3.11 should be eliminated. 6 Tr 4150. MEIU ask that the Commission order DTE Electric to develop rate comparison tools to allow its customers to better evaluate whether a TOU rate as discussed in this case would be beneficial "'as soon as possible upon the availability of the C/I TOU rate options'" which should be developed within three months of the order in this matter. MEIU's initial brief, p. 60 (citing 6 Tr 4159).

In its reply brief, MEIU highlight that DTE Electric's witness Sharma "essentially conced[es] that [DTE Electric] will ultimately do whatever it is ordered to do." MEIU's reply brief, p. 12 (citing MEIU's initial brief, p. 58). As such, because DTE Electric did not provide compelling reasons for why it should be allowed to de-prioritize C&I TOU rate implementation despite expecting to need to make modifications to its billing system, MEIU state that they feel that the Commission should "not hesitate to require DTE to implement the C&I TOU rates" on MEIU's recommended timeline within a "maximum of three months of a final order in this case" and remove enrollment caps. MEIU's reply brief, pp. 12-13.

GLREA also weighs in on this issue, discussing why TOU rates should be broadly implemented. GLREA's witness, Mr. Richter, stated that TOU rates are a more accurate reflection of cost-of-service, and that there is a basic fairness to customers with differing load profiles while ratepayers get the benefit of improved affordability with their willingness to shift their usage. *See*, 6 Tr 4805-4806. Additionally, Mr. Richter stated that TOU rates should be broadly implemented because doing so would comply with federal law, specifically PURPA.[52] Mr. Richter testifies that the Commission should direct DTE Electric "to redesign [Rate D3.11] to recover the same amount of funds from energy-capacity rates, but recover all of it during peak rate time periods" and file an adjusted rate schedule for D3.11 within 60 days of the order for this case. 6 Tr 4811.

[52] Federal Public Law 109-85 – Energy Policy Act of 2005, enacted August 8, 2005.

GLREA states that while economic efficiency is an important rate design consideration, so are affordability, fairness, understandability, simplicity, and optionality. GLREA's initial brief, pp. 6-7. GLREA asserts "that non-coincident peak demand charges fail to accurately reflect cost of service, are difficult for customers to understand, and should be replaced by time-of-use rates." *Id*., p. 8. GLREA also notes that it recommended that "75% of generation plant costs allocated to capacity be recovered during the TOU on-peak time periods" as "very little" of DTE Electric's total capacity is serving load "in all hours." *Id*. In short, not all of DTE Electric's capacity is needed at all times. However, GLREA disagrees with DTE Electric's assertion that this TOU rate should always remain optional, although it "*concede[d] the point* that it is premature to immediately require them." *Id*., p. 11 (emphasis in original). As such, GLREA requests that the Commission direct DTE Electric to redesign its D3.11 rate "to recover all of the capacity cost during the on-peak hours" while conceding that if the Commission wants a "more incremental implementation, that would also be reasonable and prudent" but that the revised TOU rate should be submitted and approved as soon as possible. GLREA's initial brief, p. 11.

In its reply brief, GLREA notes that DTE Electric expresses concern about "inadvertently set[ting] a new class peak hour on the edge of the on-peak period without stating why a shifting of peak usage would result in a negative outcome." GLREA's reply brief, p. 2 (citing DTE Electric's initial brief, pp. 319). As GLREA notes, "the peak rate period in TOU rates can always be adjusted in a later rate case, if it no longer aligns with peak demand." *Id*.

The Commission finds that MEIU and GLREA both advocate reasonable changes to DTE Electric's proposed Rate Schedule D3.11. Because Rate D3.11 was designed to be revenue neutral, the Commission finds a cap to be unnecessary and agrees with GLREA that the peak rate period in TOU rates can be adjusted in future cases as appropriate. Given the timeline of this rate case, DTE Electric has had a significant amount of time to begin developing D3.11; however, the Commission finds three months for implementation of the rate to be insufficient given DTE Electric's assertion regarding the necessary design, development, and testing activities needed to be completed. DTE Electric's initial brief, p. 320. The Commission directs DTE Electric to complete the implementation of the revised Rate Schedule D3.11 as described in this order no later than June 1, 2025, to allow it to be available to customers during the summer peak period of 2025. The Commission declines to direct DTE Electric to recover all of the capacity costs during on-peak hours.

Additionally, the Commission finds it prudent to disallow a cap of 1,000 customers as previous enrollment caps were shown to have negative outcomes. 6 Tr 4149.

2. EV Fast Charger Rate and Demand Charge Holiday

In the December 1 order, the Commission directed DTE Electric to conduct a separate COSS "to allocate appropriate costs to fast charging and design and propose rates for this specific class of customer" in its next rate case. DTE Electric's initial brief, p. 315 (citing December 1 order, p. 342). In this case, consistent with the directive from the December 1 order, DTE Electric submitted an Alternative COSS with an EV DC Fast Charging rate. *See*, 6 Tr 2776-2777; Exhibit A-16, Schedule F1.6, Schedule F1.7, and Schedule F1.8.

DTE Electric's witness, Mr. Willis, explained that DTE Electric's "proposed EV fast charger rate is designed as a secondary voltage rate with time of use power supply pricing which varies by time period and season" with power supply capacity and non-capacity rates designed "to recover the respective revenue requirements" which include an on-peak period of 1:00 p.m. to 5:00 p.m., Monday through Friday, with summer rates effective from June through September. 6 Tr 2603-2604. The four pricing periods' differential is consistent with proposed Rate Schedule D3.11

mentioned above, as well as the currently effective Rate Schedule D1.11. 6 Tr 2604. The delivery rates "are designed to recover the revenue requirements . . . including a service charge consistent with Rate Schedule D3. The distribution rate is designed as a flat volumetric rate" with the surcharges being consistent with a "similarly situated" D3 customer. 6 Tr 2604.

Mr. Willis explained that DTE Electric used determinants and rate design load shape by leveraging historical data from 21 chargers of approximately 68 known EV fast charger customers, while acknowledging that the data has two notable constraints. DTE Electric's initial brief, p. 316; 6 Tr 2604-2605. First, the small sample size can lead to volatility due to swings caused by individual customers impacting the results for the class. DTE Electric's initial brief, p. 316; 6 Tr 2605. Secondly, the sample size did not include all EV fast chargers served by DTE Electric due to "the co-location of charging load with other general service loads." DTE Electric's initial brief, p. 316; 6 Tr 2605. As such, Mr. Willis suggested that the data provided, albeit small, be used "as a starting point for discussion only and not as a rate to be implemented at the conclusion of this case." 6 Tr 2605, *see also*, DTE Electric's initial brief, p. 316.

The Staff's witness, Mr. Krause, testifies that inhibiting DCFC expansion is preferable "to encouraging the growth of something that is paying less than its cost to serve[,]" concluding that "[i]f you do not charge enough for something, then economically you will get too much demand for it." 6 Tr 5206. Mr. Krause felt that the June 2026 sunset with rolling two-year waiver should be maintained, and he opposed extending the demand waiver in Rate D3. 6 Tr 5205. Regarding the demand charge holiday, in its reply brief, the Staff states that it recommends "that any future DCFC rate is informed by the cost to serve those customers, consistent with the Commission's previous decision." Staff's reply brief, p. 14.

MEIU acknowledge the Commission's order in Case No. U-21297 as well as DTE Electric's identification of problems with the underlying data available. MEIU's witness, Dr. Sherman, also identified problems with the DCFC-specific COSS: first, "the number of customers was small and may likely not be representative. Second, given the immaturity of the market, usage of these sites likely does not represent the expected utilization rate in coming years as EV deployment increases . . . ." 6 Tr 4098. MEIU also point to the revised testimony of Mr. Willis of DTE Electric, when Mr. Willis "acknowledges the merit in continuing this discussion. The data constraints and generally small customer set *indicate that this proposal should be used as a starting point for discussion only and not as a rate to be implemented at the conclusion of this case*." MEIU's initial brief, p. 37 (citing 6 Tr 4098) (emphasis added).

Walmart's witness, Ms. Perry, also testifies that the current data used "is limited and may be more appropriate for future discussions . . . ." 6 Tr 4742. Regardless, Ms. Perry expressed concern that without a replacement EV charging rate, companies could be deterred from investing in public EV chargers within DTE Electric's service territory. 6 Tr 4742. Walmart recommended that the two-year limitation from Rate Schedule D3 be removed or that DTE Electric be required "to collaborate with interested parties to develop a public EV charging-specific rate" and to seek approval of such in the company's next rate case. 6 Tr 4742.

In its initial brief, MEIU express their concerns with the DCFC-specific COSS: 1) the small number of customers may not be representative; and 2) given the market's immaturity, usage of the charging sites is not likely to be representative of the use in coming years. MEIU's initial brief, pp. 36-37 (citing 6 Tr 4098). Regardless, MEIU argue, it is important that the DCFC rates stay in effect "until the EV charging market is able to mature sufficiently to enable the [c]ompany and the Commission to resolve the outstanding rate design questions." MEIU's initial brief, p. 37.

MEIU then discusses the "demand charge holiday" for EV fast charging "which is in fact a waiver of the demand limit on rate D3." *Id*., p. 38 (citing December 1 order, pp. 341-342). MEIU opine that there is a June 2026 waiver sunset, and Dr. Sherman stated that "existing and new customers should be allowed to access [rate scheduled D3] without the demand restriction for at least four additional years, until January 1, 2030" because it would provide "sufficient time for DCFC usage to approach a market equilibrium." 6 Tr 4098-4099. However, Dr. Sherman also stated that "it may still be premature to establish EV-specific rates even by 2030." 6 Tr 4099. MEIU further asserts that "the fact that Rate D3's demand limit has been waived to this point itself demonstrates a concern and recognition for demand charges for fast chargers *will* inhibit charge deployment so long as volumetric usage lags behind demand." MEIU's initial brief, p. 38 (emphasis in original). Thus, MEIU ask the Commission to adopt their recommendation to extend the D3 demand waiver through 2030 with an examination as to the "on-the-ground realities of the fast-charging market at that time." *Id*., p. 40.

Electrify America's witness, Ms. Davis, testifies to the coast-to-coast network of DCFC stations it has built across the country, with 42 individual DC fast chargers being located in Michigan. *See*, 6 Tr 4764. Overall, Electrify America notes DTE Electric's stance that its EV Fast Charger Rate class should be used only for discussion, not implementation and as such, Electrify America agrees that the Commission should decline to implement the rate class as proposed. *See*, Electrify America's initial brief, pp. 2-3.

EVgo testifies that while EV fast charging rates have been approved elsewhere in the country, EV charging customers "are rarely, if ever, placed in a separate rate class." 6 Tr 3305. EVgo went on to summarize various state commission decisions to conclude that it agrees with DTE Electric's proposal to take no further action at this time. 6 Tr 3306. EVgo further states that it shared Walmart's concern about the two-year limit from Rate Schedule D3, expressing that it be removed and that DTE Electric be ordered to collaborate with interested persons to develop "an optional successor rate to Schedule D3 for EV fast-charging customers, and make that successor rate available upon the expiration of the Schedule D3 exemption." EVgo's initial brief, pp. 7-8.

The Commission finds that there is not currently enough historical data to analyze given the small number of EV DC fast chargers and finds it premature to implement the company's proposed alternative COSS and rate design at this time. In order to allow time for additional chargers to be deployed to inform the development of an alternative COSS and rate design, the existing demand charge holiday should be extended an additional two years, through June 2028, under the conditions approved in Case No. U-21297 such that charging stations energized after June 2028 are permitted to remain on Rate Schedule D3 for two years on a rolling basis. DTE Electric is further directed to collaborate with interested persons to develop an optional successor EV fast charger rate to Schedule D3 which will be available to EV fast charging customers when Schedule D3 is no longer available. DTE Electric shall file its proposal for a successor EV fast charger rate, informed by input from interested parties, no later than December 1, 2026, in order to allow for approval and implementation well in advance of the June 2028 expiration of the demand charge holiday. When DTE Electric has sufficient data from EV DC fast chargers to inform the development of an alternative COSS and rate design, it may propose modifications as appropriate to any successor EV fast charger rate that has been approved by the Commission.

F. Commercial and Industrial Primary Rate Design Proposals

1. Rate Schedule D14, Primary Time of Use

DTE Electric states that it is proposing a fully optional TOU rate for its primary customers, Proposed Rate Schedule D14, as reflected in Exhibit A-15, Schedules F3 Revised and F8, based on page 372 of the December 1 order. DTE Electric's initial brief, p. 317; 6 Tr 2609. Mr. Willis explained that Proposed Rate Schedule D14 is designed "to be revenue neutral to rate schedule D11 until there is sufficient historical usage to determine the utility of, and potentially implement, a separate cost of service class or separate revenue line within D11/Other." 6 Tr 2610; *see also*, DTE Electric's initial brief, p. 317. The new rate would use D11's overall billing determinants, cost allocations, and underlying revenue requirements, with distribution charges and remaining "demand charges based on voltage level and consistent with other primary rate schedules." 6 Tr 2610. Like Rate Schedule D3.11, Proposed Rate Schedule D14 would have season and time of day variations in rate. Proposed Rate Schedule D14 would have summer pricing from June through September, and an on-peak period of 11:00 a.m. through 7:00 p.m., Monday through Friday, excluding the holidays defined in Section C11 of DTE Electric's rate book. 6 Tr 2610; *see also*, DTE Electric's initial brief, p. 317. Mr. Willis acknowledged that distribution rates "continue to be demand-based, [and] are determined separately . . ." while the off-peak rate does not vary by season. 6 Tr 2611.

Mr. Willis explained the customer risk of shifting from Rate Schedule D11 to Proposed Rate Schedule D14. First, Mr. Willis described D11 as "a demand-based rate which . . . encourages more efficient usage of the system" which "results in a lower average cost." 6 Tr 2611. Meanwhile, Mr. Willis testifies, the proposed Rate Schedule D14 would substantially reduce customer incentive to operate efficiently which, until D14 could be supported by its own cost of service class, could lead to an underrecovery, with the cost being allocated to customers in a future rate case. 6 Tr 2612. DTE Electric proposes to limit enrollment to 1,000 customers and to 50 MW of contract demand with a minimum contract term of 36 months to "support stability in cost of service and pricing and limit opportunities to arbitrage" between Rate Schedules D11 and D14.

6 Tr 2612. DTE Electric states that upon Commission approval, D14 would need to be developed, tested, and implemented into the company's billing system as reflected in Exhibit A-16, Schedule F8, with the rate available to customers by December 31, 2025. 2 Tr 2612-2613.

In its reply brief, DTE Electric argues against MEIU's assertion that its TOU rates should use an on-peak window of 1:00-5:00 p.m., stating that having the on-peak window for D14 starting at 1:00 p.m. presents the possibility of customers shifting their load to before the period, thus inadvertently creating a new system peak hour in between noon and 1:00 p.m. DTE Electric's reply brief, p. 132; 6 Tr 2635. In fact, DTE Electric's witness, Mr. Willis, testifies that the company "designed the D14 on-peak period to maintain consistency with the existing D11 on-peak period." 6 Tr 2635 (internal citations omitted). While DTE Electric posits that MEIU's arguments actually confirms that the company's concerns are reasonable, the company maintains that its "existing rates have strong historical, empirical data to support forecasts." DTE Electric's reply brief, p. 133 (citing 6 Tr 2638).

Witness Willis also stated that acceptance of MEIU's proposal of recovering all capacity costs during on-peak periods would create "extraordinarily high summer on-peak rates." DTE Electric's reply brief, p. 138 (citing 6 Tr 2642) (internal citations omitted). In highlighting why DTE Electric also disputes MEIU and GLREA's arguments, the company states that the TOU rates should be optional, and that "[i]t would be exceptionally premature to begin any discussion of requiring these rates" such that, as GLREA concedes, discussion "should wait for a future rate case." DTE Electric's reply brief, p. 136 (citing GLREA's initial brief, p. 11). DTE Electric also rejects MEIU's arguments in which they referred to a previous Consumers Energy Company (Consumers) case, as "[n]either DTE Electric nor MEIU have done a comprehensive analysis to compare the circumstances surrounding the history of Consumers primary rate proposals and its own. In addition, the Company and Consumers have fundamentally different rate offerings, different customers, and different cost of service particulars." DTE Electric's reply brief, p. 134.

As stated *supra* in Rate Schedule D3.11, Commercial Secondary Use of Time, GLREA also discussed why TOU rates, such as D14, should be broadly implemented, with many of GLREA's arguments applicable to both D3.11 and D14. *See*, GLREA's initial brief, pp. 4-11; GLREA's reply brief, pp. 1-3.

MEIU also addresses D14. Their witness, Mr. Barnes, argued that the 11:00 a.m.-7:00 p.m. on-peak window for D14 was too long to "effectively promote load-shifting" and that "it encompasses a significant number of hours that are outside of the typical timing of system peak demands." MEIU's initial brief, p. 50 (citing 6 Tr 4144). MEIU asserts that the 11:00-7:00 p.m. on-peak window is not mapped to correspond with "anticipated and historical system peaks" and thus, the peak window should be revised to 1:00-5:00 p.m. *Id*., p. 52. Furthermore, MEIU addresses the D14 cap which DTE Electric states was intended to avoid underrecovery. *See*, *id*. (referencing 6 Tr 2612). Mr. Barnes stated that such a cap limits benefits to both individual customers and the system. *See*, 6 Tr 4147. Mr. Barnes asserted that "[t]he introduction of rates should not be accompanied by new constraints on their availability" and that the proposed rates were designed to be "revenue neutral" and as such, DTE Electric's concerns about underrecovery are unfounded. 6 Tr 4147. Mr. Barnes referenced Consumers' TOU rates that were introduced in 2013 and 2017, and how both the company and its customers "ended up in the exact same position . . . as they would have been in had no cap existed in the first place . . . ." MEIU's initial brief, pp. 53-54.

The Commission finds that DTE Electric's proposed cap of 1,000 customers and total contract demand of 50 MW is unnecessary because the rate is designed to be revenue neutral and DTE

Electric has not provided additional support to warrant these limitations. Therefore, the Commission finds DTE Electric's concerns related to underrecovery to be overstated and declines to approve the proposed cap. As MEIU concluded, prior TOU rates showed that both customers and utilities were in the "exact same situation" as if no cap had been instituted. MEIU's initial brief, pp. 53-54. The Commission further finds that DTE Electric's 11:00 a.m.-7:00 p.m. on-peak window is likely too long of a period to be representative of a meaningful peak. However, given that the proposed rate was designed to be revenue neutral with the on-peak period of 11:00 a.m.-7:00 p.m., and the fact that the revenue impact of MEIU's proposed on-peak period of 1:00-5:00 p.m. has not been thoroughly analyzed, the Commission approves the use of DTE Electric's proposed on-peak period of 11:00 a.m.-7:00 p.m. at this time.

Following consultation with the Staff and interested persons, DTE Electric is further directed to propose in its next rate case a revenue-neutral rate with an on-peak window of time that is shorter than eight hours and that is based on both system peak and class peak, consistent with the method used to develop the on-peak window for the residential and commercial TOU rates, to allow greater opportunities for customers to shift loads in a manner that provides greater benefits to DTE Electric's system.

G. Streetlighting Rate Design

DTE Electric's witness, Mr. Robert Bellini, discussed Community Lighting. Mr. Bellini testifies that the company "owns, operates, and maintains approximately 199,000 Community Lighting assets which serve municipal, commercial, and residential customers." 6 Tr 3101. Mr. Bellini also mentioned that municipal customers own approximately 82,000 streetlights while there are approximately 6,400 municipal-owned traffic signals. 6 Tr 3101; *see also*, DTE

Electric's initial brief, p. 322. Mr. Bellini referenced a Community Lighting Assets table as shown below:

Asset Type	Asset Ownership	Rate Type	# of Assets	Description
Municipal OH & UG Streetlights	DTE Electric	E1 Option I	165,932	DTE Electric owned and maintained system
Municipal OH & UG Streetlights	Customer	E1 Option II	119	Municipal owned and DTE Electric maintained system
Municipal OH & UG Streetlights	Customer	E1 Option III	82,399	Municipal owned and maintained system
Commercial Outdoor Protective Lights	DTE Electric	D9	24,179	DTE Electric owned and maintained equipment
Residential Outdoor Protective Lights	DTE Electric	D9	9,147	DTE Electric owned and maintained equipment
Municipal Automated Traffic Signals (ATS)	Customer	E2	6,436	Municipal owned and maintained equipment

6 Tr 3101; *see also*, DTE Electric's initial brief, p. 322. Regarding the above chart, Mr. Bellini testifies that there are four lighting types that the company currently uses: LED, HPS, Metal Halide (MH), and Mercury Vapor (MV), but that only the first three options are still actively maintained and installed. 6 Tr 3102. Mr. Bellini also mentioned that LED lights are the most efficient, while MV is the least efficient lighting. HPS and MV lights usage have dropped significantly throughout the recent years, with LED lights increasing in usage, "primarily to municipal driven conversions." 6 Tr 3104. DTE Electric states that "[i]n 2023, our key lighting vendors informed us that they will be or are considering phasing out their HPS product lines in 2024" and as such, the company has decided to sunset its active maintenance and support for that lighting source either by January 1, 2025, or when the HPS inventory has been depleted, whichever occurs earlier. DTE Electric's initial brief, p. 322; 6 Tr 3105.

To manage replacement of HPS fixtures that require maintenance upon depletion of HPS inventory or after 2024, DTE Electric proposes to replace such with "equivalent LED luminaires at no additional charge to the customer" along with offering a labor credit of $65 to the municipalities that have proactively converted to LEDs already. DTE Electric's initial brief, p. 323; 6 Tr 3106. To effectuate the transition, the company notified its municipal customers via email highlighting why the change was occurring along with the benefits of LEDs and the opportunity to receive the labor credit. 6 Tr 3107. To correspond with the conversion from HPS to LEDs, DTE Electric proposes a language change to E1 Option I and D9 tariffs as follows: "'Effective January 1st, 2025, new high pressure sodium (HPS) fixtures will no longer be available. Customers with existing HPS fixtures will continue to receive service until those fixtures fail. At that time, the fixture will be converted to an LED luminaire.'" 6 Tr 3107. Thus, DTE Electric disagrees with the arguments of MI-MAUI, Ann Arbor, and the Staff as outlined below, and the company proposes a Staff-facilitated workshop to discuss OMS capabilities, enhancement potential, and whether investments would be prudent. *See,* DTE Electric's initial brief, pp. 323-326.

In its reply brief, DTE Electric argues against MI-MAUI, Ann Arbor, and the Staff's credit proposal while maintaining its position to charge municipalities converting early to LEDs. In addition, with regards to MI-MAUI's position of creating a bill credit method to refund CIAC to customers who converted early, DTE Electric states that such a proposal attempts to circumvent the Commission's prior decisions in both its and Consumers' prior rate cases, stating "[t]his is the 3rd consecutive case in which Witness Bunch has advocated for the elimination of CIAC." DTE Electric's reply brief, p. 126 (citing 6 Tr 3153). DTE Electric also states that Mr. Bunch did not introduce any new evidence to prove that DTE Electric has altered its Commission-approved

CIAC methodology. DTE Electric's reply brief, p. 137. DTE Electric claims that MI-MAUI's proposal is "novel and unjust" because replacing failed HPS lights with LED lights "is no different than the Commission approved MV to LED replacement process upon failure." *Id*. DTE Electric further points to MI-MAUI's inconsistent proposals regarding CIAC. In Case Nos. U-21297 and U-21389, Mr. Bunch stated that CIAC should be eliminated while also arguing in Consumers' case that customers should be charged in full for new streetlights. *Id*. (citing 6 Tr 3134). DTE Electric contends that to approve MI-MAUI's bill credit would set a "dangerous precedent" in ignoring longstanding Commission precent that approved CIAC policy, along with resulting in $15-20 million in expenses associated with converting 40,000 remaining HPS lights to LEDs. DTE Electric's reply brief, p. 137; 6 Tr 3155. DTE Electric states that adopting MI-MAUI's proposal would significantly increase municipal streetlighting costs while reversing the Commission's current CIAC position. DTE Electric's reply brief, pp. 137-138. Thus, DTE Electric maintains its position that a Staff-facilitated workshop should be held on this issue.

In its initial brief, the Staff outlines the arguments of Ann Arbor and MI-MAUI as set forth below. While the Staff does not agree with Ann Arbor's argument, it does agree that it is appropriate for customers who paid for LED conversions to receive a streetlighting conversion credit proposal as recommended by MI-MAUI. 6 Tr 4813. The Staff also notes that the Commission has previously approved lighting conversion credits on this issue for Consumers. In its testimony, the Staff highlights three features to Consumers' bill credits which it feels DTE Electric should adopt: 1) they are time-limited; 2) each customer received the same credit amount per LED per year; and 3) the credit amount is adjusted each time new rates incorporate changes. 6 Tr 4305. This scheme would allow customers that paid CIAC for LED lighting conversion to receive a time-limited, per-lamp credit. The Staff also agrees with MI-MAUI's recommendation that the Commission direct DTE Electric to file a bill credit method and initial credit amount in its next rate case, consulting with the Staff and intervenors to develop the credit method. 6 Tr 4308.

In its reply brief, the Staff states that while it supports MI-MAUI's streetlighting conversion credit proposal, it does not support the proposal to eliminate CIAC for planned LED conversions. The Staff dismisses Ann Arbor's argument in its reply brief because, it argues, "[c]ustomers choosing to convert to LED prior to the [c]ompany's decision to begin replacing failed lamps with LED did so under the condition that LED service was not standard. Now that such service will become standard in 2025, it is reasonable to make those customers whole via a bill credit." Staff's reply brief, p. 49 (citing 6 Tr 4913). The Staff further asserts that after 2025, customers who choose to "'jump the line'" and convert to LED before the current lights fail should be charged CIAC and should not qualify for the conversion credit because "they will have known in advance that they will eventually receive LED service at no additional cost." Staff's reply brief, p. 49.

Ann Arbor's witness, Mr. Naheedy, testifies that cities like Ann Arbor should receive a bill credit if they convert early to LED lights to equal the amount other customers will not have to pay for later conversion "so that they are not paying both for the entirety of their own conversion and a portion of others." Ann Arbor's initial brief, p. 13; 6 Tr 4276. Ann Arbor also states that, in response to the Staff, it did not intend for it to be the only city receiving its proposed credit, while supporting adopting MI-MAUI's streetlight conversion credit proposal. Ann Arbor's initial brief, p. 14. Ann Arbor notes that while LEDs are now the standard streetlight, "DTE [Electric] still intends to charge customers a CIAC for proactive group conversions and has no intentions of paying a credit to customers who already paid a CIAC to convert to LEDs[,]" thus concluding that other communities are "saved" from contribution to their own LED conversions which is "'an absurd and unfair result'" for cities like Ann Arbor that were proactive in their conversions. *Id*., p. 15; 6 Tr 4276.

In its reply brief, Ann Arbor maintains that customers who are proactive in their conversions "pay both the entire cost of converting their own streetlights <u>and</u> a portion of the cost of the LEDs installed in other communities[,]" thus subsidizing the reactive conversion of other communities "through rates." Ann Arbor's reply brief, p. 5 (emphasis in original). Ann Arbor again suggests that the city, MI-MAUI, and the Staff all assert that "this inequality can be resolved through the provision of credits to communities who have proactively converted to LEDs" such that the credits "would be socialized through rates, just as the cost of reactive conversions are" so that proactive communities are "not financially disadvantaged." Ann Arbor's reply brief, p. 5.

In its initial brief, MI-MAUI states that it wishes to eliminate the CIAC for planned streetlight conversions. MI-MAUI's argument is based on the idea that LED lighting is now the default and most common lighting choice, "so charging communities a CIAC as if they were selecting a specialty, non-standard light is inappropriate." MI-MAUI's initial brief, p. 40. MI-MAUI asserts that the market decided the issue, because in November 2023, DTE Electric notified its community lighting customers that it would implement LEDs as its new default light, replacing HPS streetlights. *Id*.; *see also*, 6 Tr 3105. MI-MAUI's witness, Mr. Bunch, testifies that it is appropriate to reimburse customers who paid CIAC on their conversions "if all customers will begin to be upgraded to LED service via spending in base rates." 6 Tr 4913. MI-MAUI also acknowledges that Ann Arbor agrees with its credit structure proposal. MI-MAUI's initial brief, p. 41. MI-MAUI confronts the idea that Consumers previously charged CIAC for reactive LED conversions by stating that Consumers "had never charged CIAC for reactive conversions; indeed it did not perform reactive conversions at all until it instituted its no-CIAC burnout conversion policy. Before that, Consumers did charge CIAC for planned conversions, and still does . . ." but that demand has declined significantly once customers realized they could get LEDs "at no up-front cost merely by waiting for existing HID lamps to burn out." *Id*., p. 42. MI-MAUI also highlights that in 2023, DTE Electric previously took the position that having some customers get LEDs at no additional cost would cause those who paid for upfront conversion to subsidize their neighbors. *Id*. MI-MAUI states that it, Ann Arbor, and the Staff agree that early converters would be charged twice and as such, "a bill credit is an appropriate way to avoid the subsidy that 2023 DTE [Electric] rightfully identified would result." *Id*., pp. 42-43. Furthermore, MI-MAUI testifies that it is cheaper to convert streetlights to LEDs "via planned group conversions" rather than doing so individually as they burn out. 6 Tr 4301, 4309-4310.

In its reply brief, MI-MAUI reasserts that group conversions are less expensive than fixing lights as they burn out. MI-MAUI's reply brief, p. 6 (citing 6 Tr 4309-4310). It argues that DTE Electric now proposes to charge a CIAC even in less expensive cases of group conversions which act as a reactive conversion "instead of HPS replacements as a standard[,]" creating a materially different cost scenario. MI-MAUI's reply brief, p. 6. As such, MI-MAUI reaffirms its position.

The Commission finds that, similar to the LED conversion credit approved in Case. No. U-21389 for Consumers, DTE Electric should adopt a time-limited bill credit per each LED light per year which is adjusted as new rates incorporate changes. 6 Tr 4305; *see also*, March 1, 2024 order in Case No. U-21389, Attachment B, Sheet No. D-94.00. This provides early LED adopters with a bill credit which is equitable since LED conversions will be standard in 2025 such that early adopters are not subsidizing municipalities that have waited until LED conversion was announced.

XI. OTHER PROPOSALS

A. Reliability Performance and Capital Investment

In both its initial brief and its reply brief, DTE Electric references Section VI.C. of its initial and reply briefs regarding ROE, while referencing Section VIII.A. regarding IRM in its initial brief, *a priori*. As such, the parties' positions will not be discussed in detail here.

B. Environmental Justice in System Reliability and Distribution Planning

DTE Electric states that for its service territory, by census tract, it developed reliability data by quartile for both SAIFI and SAIDI, and it provided maps of such. DTE Electric's initial brief, p. 329; *see also*, 3 Tr 373-377. This data was developed per its DGP and per the Commission's guidance in Case No. U-21297, p. 93. DTE Electric's initial brief, p. 329. The company used the MiEJScreen tool to calculate vulnerable census tracts at 5% gradations, identifying 483 census tracts as vulnerable communities per a MiEJScreen score at or above the 80th percentile. *Id*.; *see also*, 3 Tr 378. These 483 census tracts are 29% of the company's total census tracts and were deemed to have "better reliability than the system average in SAIFI and SAIDI in both All-Weather and non-MEDs." 3 Tr 378; *see also*, DTE Electric's initial brief, p. 329. DTE Electric provided various tables relating to SAIFI and SAIDI, which showed that its "vulnerable customers in the 80th percentile and above see better reliability than the system average in SAIFI and SAIDI in both All-Weather and Non-MED." 3 Tr 384.

DTE Electric further states that it had evaluated its investment projects and programs such as 4.8kV Hardening, 4.8kV conversion, and tree trimming to reach vulnerable communities and found that such projects and programs result in "reduction in the frequency and duration of outages and fewer downed wires." 3 Tr 385. DTE Electric provided tables which showed its 2024-2025 investment in vulnerable communities, with investments made as follows: 85% of investments in 4.8kV Hardening were directed to vulnerable communities, 64% in 4.8kV conversion, and 25% in tree trimming. 3 Tr 392; *see also*, 3 Tr 387-391. By doing so, DTE Electric asserted, "[p]rojects in more vulnerable [EJ] areas will receive a higher score and have a better chance of being selected for investment." 3 Tr 392.

DTE Electric stresses that it felt that the DAAOs' witness, Mr. Koeppel, had "apparent misunderstandings" because the company does, in fact, evaluate projects and programs using multiple factors such as "reliability, safety, and EJ" which results in a portfolio of investments that support multiple grid objectives for all customers. DTE Electric's initial brief, p. 331. DTE Electric also maintains that it uses "the description of 'vulnerable' to describe customers in geographic areas with 80-100 MiEJScreen scores and the 'non-vulnerable' [description] to discuss those with scores less than 80. The highest possible score for an area is 100." *Id*. (citing 3 Tr 450-452). DTE Electric also touches upon the DAAOs' criticism of the CODI investments, stating that witness Koeppel's description of CODI investments was "inaccurate and unsupported[,]"ignoring census tracts while stating that "'population density is a significant factor in reliability performance.'" DTE Electric's initial brief, pp. 331-332 (citing 3 Tr 384).

DTE Electric then addressed GLREA's testimony below, asserting that its EJ analysis "uses more recent data, the MiEJScreen tool," and data for the company's own customers. DTE Electric's initial brief, p. 332. However, the Company agrees that conversion and hardening programs "are necessary to support improving reliability for areas served by the [c]ompany's oldest 4.8kV infrastructure" which "may require more significant repairs." *Id*. (citing 3 Tr 454); 3 Tr 454.

Lastly, DTE Electric addresses the testimony of the CEOs, stating that the updated regression analysis used by the CEOs is "fundamentally flawed" while stating that the company "is actively working on EJ regression analysis with Witness Tan and [the] Staff . . . ." DTE Electric's initial brief, pp. 332-333 (citing 3 Tr 455-457).

In its reply brief, DTE Electric quickly summarized that it continues to disagree on the specific issues raised by the other intervening parties. The company notes that the Staff also disagrees with the DAAOs on the CODI program, stating that the Staff "supports the projected spending for nearly all of the strategic capital programs. The projected numbers are in line with the [c]ompany's current path to improve the reliability, resilience, and safety of the electric system." DTE Electric's reply brief, p. 131 (citing Staff's initial brief, p. 196). DTE Electric also noted that even the CEOs "'recommend that the [c]ompany continue to work with [the] Staff and the CEO[s] on its regression analysis'" and as such, DAAOs' reliance on Mr. Tan's testimony "is misplaced." DTE Electric's reply brief, p. 141 (citing the CEOs' initial brief, p. 29).

The Staff acknowledged the testimony of DTE Electric's witness, Mr. Deol, that DTE Electric's CODI customers "in the target areas are experiencing poor reliability due to load growth and aging infrastructure." Staff's initial brief, p. 196; 6 Tr 4414. The Staff also recognized Mr. Deol's testimony that the CODI project drivers "were not driven completely by reliability improvement, but also to address capacity for load growth, maintaining sufficient redundancy, and addressing aging infrastructure" while benefitting "all citizens of the City of Detroit and the surrounding communities." Staff's initial brief, p. 196; 5 Tr 1237. Thus, the Staff supports DTE Electric's CODI spending as its "projected numbers are in line with the [c]ompany's current path to improve the reliability, resilience and safety of the electric system." Staff's initial brief, p. 196.

The DAAOs begin their discussion of EJ by remarking that DTE Electric's reliance on MiEJScreen's 80th percentile threshold is improper because it excludes other vulnerable communities. DAAOs' initial brief, pp. 49-50. The DAAOs admit that the MiEJScreen tool is a useful starting point, but state that it should not be relied upon exclusively because "a census tract with an overall MiEJScreen about the 80th percentile may still contain significant variation and heterogeneity in terms of income levels, housing quality, energy burdens, and other relevant factors . . . that require more targeted and customized interventions." *Id*., pp. 50; 6 Tr 4411. The DAAOs illustrate their point by focusing on CODI, which they assert "has prioritized investment in areas where the white population is increasing rapidly." DAAOs' initial brief, p. 50 (referring to Exhibit DAO-10). This means that the MiEJScreen tool would have DTE Electric investing in communities that are not actually the most vulnerable. DAAOs' initial brief, p. 50. The DAAOs' witness, Mr. Tan, testifies that densely populated areas have better SAIDI while BIPOC areas have worse SAIDI, meaning that a densely populated BIPOC community "could have better reliability than the system average" while having worse reliability than an equally densely populated white community, thus resulting in an inequity. DAAOs' initial brief, p. 55; *see also*, 6 Tr 3279. The DAAOs express concern that this scenario is occurring in DTE Electric's CODI investments, resulting in increased inequity. DAAOs' initial brief, p. 55.

The DAAOs also reference that the federal Environmental Protection Agency (EPA) recommends using more than just the MiEJScreen's 80th percentile threshold to analyze vulnerable tracts and address EJ, with the EPA recommending that the MiEJScreen's threshold be used merely as a "starting point." DAAOs' initial brief, p. 51 (referencing Exhibit DAO-29). Thus, the DAAOs assert that DTE Electric "should conduct additional analysis before designating vulnerable census tracts and calculating investments in EJ communities." DAAOs' initial brief, p. 51. Furthermore, the DAAOs state that when reviewing DTE Electric's reliability maps, several of the CODI census tracts have better than average reliability per SAIDI and SAIFI, while the company ignores census tracts below the 80th percentile which happen to represent "many households with low incomes, poor housing quality, high energy burdens, and cumulatively impacting social vulnerabilities." DAAOs' initial brief, p. 52; 6 Tr 4441, 4414-4416. The DAAOs also reference the CEOs' witness, Mr. Tan, who conducted a regression analysis that showed an increase in BIPOC population is correlated with a decrease in utility reliability. DAAOs' initial brief, p. 54; *see also*, 6 Tr 3279.

In their reply brief, the DAAOs point out that DTE Electric reviews sub-circuit factors, suggesting that it acknowledges that more granular data beyond the MiEJScreen is of value. DAAOs' reply brief, p. 15. The DAAOs assert that if "a different equity methodology was used for CODI, DTE [Electric] should be required to fully describe the alternative approach and justify why it deviates from the [c]ompany's standard [Global Prioritization Model (GPM)] framework." *Id*., p. 17. As such, the DAAOs ask that DTE Electric provide a detailed explanation of how equity was evaluated for CODI, including a statement of "whether and how the GPM's EJ component was applied." *Id*.

The CEOs begin their EJ discussion by listing past rate cases in which the Commission ordered DTE Electric to consider equity and EJ, including an order that the company "implement 'grid equity' recommendations to include requirements to provide community vulnerability information in environmental analyses and greater transparency for projects and programs in future rate cases." CEOs' initial brief, p. 22; December 1 order, p. 375. The CEOs then mention that other Midwest states consider equity and EJ in their planning and rate cases, while asking that the Commission order DTE Electric "to continue to incorporate equity and environmental justice considerations in its planning processes, particularly in ways that go beyond reliability analysis." CEOs' initial brief, pp. 23-24. To do this, the CEOs provide three suggestions:

1) that DTE Electric track granular mapping analyses that include tracking six additional measures involving census blocks as listed below:

a. Average energy burden at the census block group level;
b. Percentage of residential customers disconnected per census block;
c. Percentage of low-income customers in each census block group that participated in one or more energy assistance programs a year;
d. Percentage of low-income customers in each census block group that participated in a payment plan;
e. Percentage of residential customers in each census block group enrolled in Shutoff Protection Plan in a year; and
f. Percentage of low-income residential customers in each census block group that participated in the Company's energy efficiency program in a year.

2) that DTE Electric conduct regression analysis in both rate and distribution planning cases as regression analysis looks at various demographics such as race, population density, and income; and

3) that the Commission order the company to use Illinois as an example to create a comprehensive affordability program to reduce the affordability gap and address excess energy burden.

CEOs' initial brief, pp. 24-30; 6 Tr 3200-3202. The CEOs request that the Commission order DTE Electric to report on the six additional measures listed above, continue working with the CEOs and the Staff on its regression analysis while sharing its analysis in future cases, and, per the DAAOs, propose a process for interested persons to assist in implementing a comprehensive affordability program. CEOs' initial brief, pp. 27-30. The CEOs believe that these actions would assist DTE Electric in improving its reliability, delivering more affordable electric service while addressing its customers' current high energy burdens. *Id.*, p. 30.

In their reply brief, the CEOs reassert that EJ involves more than just reliability concerns, stating that "the Commission has recognized that 'more work is necessary.'" CEOs' reply brief, p. 10 (quoting November 18 order, p. 459). The CEOs also affirm the DAAOs' recommendations, including that the Commission order DTE Electric to "'track and provide information on the affordability gap in its service territory.'" CEOs' reply brief, p. 12 (quoting DAAOs' initial brief, p. 94). Thus, the CEOs agree with the DAAOs that DTE Electric must invest in its distribution grid while working to create better solutions to mitigate impacts of its rates for low-income customers. CEOs' reply brief, p. 12.

While MNSC did not directly address EJ in their initial brief, they did lend support to the CEOs and DAAOs' positions in their reply brief. MNSC agreed with the DAAOs' suggestion for DTE Electric to improve its infrastructure equity analysis, including going beyond merely relying on the MiEJScreen tool. MNSC's reply brief, p. 39. MNSC also agreed with the CEOs' recommendation for DTE Electric to improve its mapping to more accurately identify vulnerable populations. *Id*.

The Commission finds that the CEOs provided several additional EJ factors that DTE Electric could consider. The CEOs request that the Commission order DTE Electric to report on the six additional measures listed above, continue working with the CEOs and the Staff on its regression analysis while sharing its analysis in future cases, and, per the DAAOs, propose a process for interested persons to assist in implementing a comprehensive affordability program. The Commission acknowledges that through its use of the MiEJScreen tool and its investment projects and programs such as 4.8kV hardening, 4.8kV conversion, and tree trimming, DTE Electric is already working to improve electric service. As the Staff recognized, DTE Electric's EJ considerations already go beyond mere reliability improvement. As such, the company has illustrated reasonable and prudent EJ considerations, thus justifying its CODI spending as it also reviews multiple factors such as reliability and safety in addition to EJ to support its grid objectives for all customers. DTE Electric's initial brief, p. 331. While the CEOs and DAAOs provide several additional EJ-related factors that DTE Electric could consider, the Commission finds the use of the MiEJScreen to be a reasonable starting point for DTE Electric's equity-related analyses. The Commission also recognizes the work done by DTE Electric to map its reliability investments in relation to vulnerable communities; notes that 85% of investments in 4.8kV hardening were directed to vulnerable communities, along with 64% of investments relating to 4.8kV conversions; and that, on average, vulnerable communities are seeing better reliability performance for both SAIDI and SAIFI in both all weather and when excluding MEDs. As such, while the Commission continues to believe that "more work is necessary," per the November 18 order, p. 459, including avoiding the potential racial disparities and inequities in performance between communities raised by the DAAOs, in this case, DTE Electric's reliance on the MiEJScreen to inform its EJ efforts is well-supported. The Commission looks forward to the company's continued work with interested persons to incorporate additional EJ-related considerations, including avoiding creating performance disparities between communities of similar density with differing demographic profiles as outlined by the DAAOs' witness Tan, into that process and in reviewing utility initiatives.

C. Contributions in Aid of Construction and Standard Allowance Table

DTE Electric disagreed with MNSC's CIAC report recommendation as discussed below "because the [CIAC cost] information is already provided in the [c]ompany's publicly-available Exhibit A-12, Schedule B5.4 for each rate case[,]" and it stated that a five-year pattern for such information is appropriate. DTE Electric's initial brief, p. 334 (referencing 6 Tr 3091). Furthermore, DTE Electric disagrees with Ann Arbor's proposal to limit CIAC for customers on 4.8kV circuits (as discussed below), stating that it "is not aware of situations in which similarly-situated customers on the 4.8kV and the 13.2kV systems have paid substantially different CIAC fees based on the voltage of the system to which they are connected." DTE Electric's initial brief, p. 334. DTE Electric contends that its customers—including its most vulnerable customers—

would be forced to pay for required system upgrades and extensions if developers were not charged "for their share." DTE Electric's initial brief, p. 334 (citing 6 Tr 3092).

In its reply brief, DTE Electric reiterated that it felt that MNSC's request for a report is inappropriate because the company already publicly provided this information as it does in every rate case, via its Exhibit A-12, Schedule B5.4, although it agrees with a five-year schedule. DTE Electric's reply brief, p. 142. Regarding Ann Arbor's argument, DTE Electric maintains that such should be rejected and states that Ann Arbor "adds nothing in substance in maintaining its proposal to essentially subsidize developments in its community at the expense of other DTE Electric customers." *Id*.

MNSC's witness, Mr. Denzler, testifies to keep CIAC "accurate and relevant, so that new business customers pay their fair share of new business costs." MNSC's initial brief, pp. 196-197; 6 Tr 3776. To do so, he recommended that in its next rate case, DTE Electric be ordered to provide a report "detailing the impact of the CIAC changes" that should "include a review of the new business construction costs and CIAC received, with comparison to historic and projections of future new business construction costs and CIAC received." MNSC's initial brief, p. 197; 6 Tr 3777. Mr. Denzler also testifies that "the Commission should ensure that CIAC sees regular updates in the future so that it does not drift so far from actual costs again" such that a regular review of the CIAC costs occur "at least once every two years, but certainly no longer than once every five years." 6 Tr 3777.

In its initial brief, Ann Arbor states that older cities like Ann Arbor, Detroit, Grosse Pointe, and Highland Park that have not been upgraded to a 13.2kV system are unfairly charged a CIAC despite the fact that DTE Electric plans to convert all 4.8kV grid infrastructure to 13.2kV infrastructure eventually. Ann Arbor's initial brief, p. 26; *see also*, 6 Tr 4269. Ann Arbor posits that the costs of the required system upgrades should be paid "by all customers just as other 4.8kV-to-13.2kV projects are." Ann Arbor's initial brief, p. 26. Ann Arbor stated that developers increasing the electric load capacity of a site should be charged the same CIAC regardless of whether the system is a 4.8kV or a 13.2kV system, which has 2.5 times the power capacity. *Id*., p. 25; 6 Tr 4269; *see also*, Exhibit AA-32. As Ann Arbor's witness, Dr. Stults, testifies, "ratepayers as a whole benefit from increased density by reducing the infrastructure needed to serve the customer base. Thus, it is to everyone's benefit not to adopt a policy that effectively encourages sprawl." 6 Tr 4269.

The Commission recognizes the similarity between this issue and the streetlighting credit issue discussed *supra*. The Commission finds Ann Arbor's argument regarding CIAC for 4.8kV customers to be persuasive. However, the Commission disagrees with Ann Arbor's suggestion that it should limit CIAC to 4.8kV customers because, while a customer has no control over which system it is on (4.8kV or 13.2 kV), all customers should pay a CIAC as appropriate in correlation to when DTE Electric converts the rest of its 4.8kV grid infrastructure to 13.2 kV infrastructure. However, the Commission finds that there is insufficient information on the record to draft an appropriate tariff. Therefore, the Commission directs DTE Electric to propose in its next general rate case, in consultation with the Staff and other interested parties, tariff language to modify its current Tariff C-27.00 to include a limited CIAC waiver related to the difference in costs associated with customers connected at 4.8 kV and those connected at 13.2 kV. Furthermore, the Commission finds that there is no reason to increase the frequency of DTE Electric's reports as it files its Exhibit A-12, Schedule B5.4 in each of its rate cases.

D. Voluntary Separation Incentive Program

In its initial brief, DTE Electric disagreed with the Attorney General and MNSC's VSIP proposals mentioned below. *See*, DTE Electric's initial brief, pp. 335-336. DTE Electric instead argued that while its VSIP will lower costs, "it is more prudent to wait until any savings are actually realized" after the company has filled any open positions. DTE Electric's initial brief, p. 335 (citing 6 Tr 2911-2912); 6 Tr 2912. DTE Electric testifies that it expected to hire 184 new employees to fill key positions after VSIP implementation and that "it is patently unreasonable and contrary to the record to assume that the number of employees hired will be zero." DTE Electric's initial brief, p. 336; 6 Tr 2913-2914. Thus, DTE Electric concluded that any discussion of reducing its O&M recovery based on the VSIP should be dismissed as being "premature, unreasonable, and unlawful." DTE Electric's initial brief, p. 336. In its reply brief, DTE Electric reiterated that employee savings for 2025 "are speculative and subject to offset" given that it will need to hire new employees. DTE Electric's reply brief, p. 143.

The Attorney General's witness, Mr. Coppola, testifies that DTE Electric offered a VSIP plan to 1,025 employees and 1,622 Corporate Services employees, with 140 employees and 249 Corporate Services employees enrolling, for a total of 389 of those employees accepting the separation plan. 6 Tr 3687. Mr. Coppola noted that in its discovery responses, DTE Electric "stated that up to $20.3 million of labor and benefit cost savings could be achieved in 2025." 6 Tr 3687 (citing Exhibit AG-45). While Mr. Coppola testifies that the preliminary cost savings for 2025 should be included in the test year for a reduction in O&M expenses, he included "only half, or $10.1 million" and so that the company would not receive a windfall. Attorney General's initial brief, p. 63; 6 Tr 3688. Mr. Coppola recommended that the Commission accept that reduction to DTE Electric's forecasted O&M expense for the projected test year. 6 Tr 3688. In her reply brief, the Attorney General argued that Mr. Coppola's savings "will unequivocally be realized during the projected test year," so allowing the company to retain such "without factoring them into the revenue requirement in this rate case would be a windfall . . . ." Attorney General's reply brief, p. 47.

In its initial brief, MNSC relied on its witness, Mr. Denzler, who testifies that "'it does not make sense that the Company would include costs for employees that are no longer there.'" MNSC's initial brief, p. 157 (citing 6 Tr 3779). In short, it is unreasonable for DTE Electric to use pre-VSIP staffing levels as a baseline for cost recovery, whereas it would be reasonable "to expect that staffing levels after that buyout should become the new budgetary norm." 6 Tr 3779. Mr. Denzler also criticized DTE Electric's decision to effectuate the VSIP in 2024 while choosing 2025 as its projected test year "in the midst of significant staffing fluctuations" such that it has failed to properly justify its staffing for 2025. 6 Tr 3779. To strengthen this position, Mr. Denzler pointed to DTE Electric's discovery response to AGDE-1.23c, which stated that the "estimate will continue to evolve . . . ." 6 Tr 3779. MNSC further argues that "the staffing reductions are known" whereas the "full extent of future hires, and how much those hires will offset savings from the departures, is not known." MNSC's initial brief, p. 159. As such, approving the O&M expense for the projected test year based on pre-VSIP staffing levels would lead to DTE Electric over-earning in 2025. *Id.*, p. 160. Thus, Mr. Denzler recommended that the Commission establish a post-VSIP staffing cost as a baseline for the projected test year O&M expense "based on VSIP departures to date, irrespective of any backfilling" and reduce DTE Electric's O&M expense by $20.2 million. 6 Tr 3780; *Id.*, p. 157. Mr. Denzler ended by suggesting that DTE Electric seek approval of expense increases from new hires in its next rate case. MNSC's initial brief, p. 160.

The Commission does not find DTE Electric's exclusion of $20.2 million in estimated VSIP savings as a reduction of future O&M expenses to be reasonable and prudent. While DTE Electric argues that it will need to hire employees to replace its fundamental employees who took the VSIP, the company concedes that its staffing levels "continue to evolve." 6 Tr 3779. As such, the Commission finds it reasonable and prudent to decrease DTE Electric's O&M expenses per the Attorney General's recommendation of $10.1 million. This decision has been included in the total adjusted net operating income.

E. Nanogrids and Microgrids

In its initial brief, GLREA provides eight advantages to nanogrids and microgrids. They are described by GLREA as follows:

> (1) enhancing localized generation which can decrease demand on distribution system, resulting in lower costs;
>
> (2) expanding energy storage resources, which can mitigate impacts resulting from service outages, can reduce demand on the distribution system, resulting in cost savings, and which can better match generation resources with loads on the distribution systems;
>
> (3) creating independent "island" type generation, which can reduce peak loads, and provide backup resources during outages;
>
> (4) improving energy management and control by optimizing diversified sources of generation, energy storage, and by better matching ever changing loads;
>
> (5) improving grid interaction and flexibility by utilizing microgrids to contribute to addressing peak loads, outages, and exchanging power by using two-way communication and real-time smart grid technologies;
>
> (6) enhancing the resilience, reliability and diversification of the grid, and by reducing the dependencies on centralized power plants, and distribution systems;
> (7) strengthening energy efficiency and sustainability by better addressing energy needs and reducing transmission and distribution line losses; and
>
> (8) developing energy resources obtainable from integration of electric vehicles as a contributing component beneficial to the grid.

GLREA's initial brief, pp. 30-31; *see also*, 6 Tr 4876-4877.

The DAAOs also call for greater utilization of microgrids and begin their discussion by defining microgrids as "localized electricity systems that can operate independently from the main power grid, include an energy generation source and a control system to manage power flow, and may incorporate energy storage." DAAOs' initial brief, p. 81; *see also*, 6 Tr 4607-4608. The DAAOs explain that microgrids can use a variety of energy sources, such as fossil fuels; that they provide a continuous power supply to critical loads during prolonged power outages; and that they can even provide power to the main grid. DAAOs' initial brief, p. 81; *see also*, 6 Tr 4607. The DAAOs give several examples of how microgrids provide benefits to individual customers and especially low-income households, such as allowing refrigerators to continue operating, thereby eliminating food spoilage and the resulting economic loss from such as a typical "well-stocked modern refrigerator would hold about . . . $325 [in] food costs in April 2024." DAAOs' initial brief, p. 82; *see also*, 6 Tr 4602 (citing Exhibit DAO-274). The DAAOs also provide examples of how microgrids aid community facilities such as "hospitals and emergency response services, helping to meet essential medical and safety needs." DAAOs' initial brief, p. 83; *see also*, 6 Tr 4606-4607. Furthermore, the DAAOs explain that microgrids running on renewable energy sources "offer significant climate benefits by reducing greenhouse gas emissions" thus "align[ing] with Michigan's goal to achieve net-zero greenhouse gas emissions by 2050." DAAOs' initial brief, pp. 83-84.

The DAAOs argue that individual microgrid customers should not have to pay different rates. They argue that those who suffer the most from poor grid performance are those who could benefit the most from microgrids, especially those who experience technical challenges due to areas "'vulnerable to severe weather.'" DAAOs' initial brief, p. 86 (quoting 4 Tr 687-688). In short, the

DAAOs state that "those who would benefit from these microgrids would start to receive the kind of service to which they are entitled and for which they have been paying but have not been receiving; they should not be required to pay for or pay more for a microgrid that benefits them." DAAOs' initial brief, p. 86. The DAAOs conclude by arguing that microgrids decrease the burden on the main grid while providing "broader societal benefits . . . [that] justify their implementation and financing by ratepayers generally." *Id*., p. 87. The DAAOs also state that the Commission should order DTE Electric to develop various Highland Park microgrids because Highland Park has a "history of long-duration outages that affect its low-income population" such that microgrids would "significantly enhance community resilience." *Id*., p. 88 (citing 6 Tr 4628). Thus, the DAAOs request that the Commission do the following:

- Order DTE to conduct a study of the benefits of microgrids that includes analyses of:
    - Non-energy and carbon reduction benefits, and
    - The disproportionate costs of long-duration outages on low- and moderate-income households.

- Initiate an analysis of the ways that front-of-the-meter microgrids could be encouraged and implemented in Michigan, particularly in ways that will allow for community ownership of the distributed generation and storage resources (or controlled by the community such as with a special governing board) and the terms under which they would have access to DTE's distribution system.

- Set conditions and incentivize microgrid development in areas with poor reliability, especially in vulnerable and historically underserved communities whose members disproportionately lack the means to address the impacts of outages on their households.

- Establish and implement guidelines for geographic targeting, cost recovery, and ownership models for microgrids that balance utility, customer, and public interests.

- Order DTE and other utilities to revise their existing tariffs or develop a new tariff specifically for microgrids.

- Develop microgrids for Highland Park to include City Hall, the fire station, and the Senior Building.

DAAOs' initial brief, pp. 87-88; *see also*, 6 Tr 4625-4630; 6 Tr 5199-5201.

In its initial brief, DTE Electric argues that the technologies GLREA described are currently available to the company's customers under its current tariffs. DTE Electric's initial brief, p. 336; 6 Tr 2640. Furthermore, DTE Electric testifies that GLREA's proposed microgrids that include "multiple individual customers, islanded groups of individual customers, and 'submeters' across neighborhoods" would be inappropriate because they would "require fundamental change to utility regulation in Michigan and the concept of who is a utility." DTE Electric's initial brief, p. 336; 6 Tr 2640. DTE Electric states that if the Commission were to align itself with GLREA's proposal, that "it should be addressed in a separate interconnection rules forum." DTE Electric's initial brief, p. 337; 3 Tr 468.

In its reply brief, DTE Electric disagreed with the DAAOs' position on microgrids in support of socialized cost recovery, stating that "users of microgrids should pay the costs arising from those investments. The DAAO[s have] not provided compelling evidence to the contrary." DTE Electric's reply brief, p. 144.

In its initial brief, the Staff also rebuts the DAAOs' testimony that highlighted using diesel generation to fuel microgrids. Staff's initial brief, p. 130. The Staff highlights that Public Act 235 of 2023 requires "an electric provider to have a portfolio of 100 percent clean energy by 2040" and as such, microgrids should not include fossil generation. *Id.*; *see also*, 6 Tr 5199; MCL 460.1051. The Staff also advocated for microgrid users paying a surcharge for their own costs as there is increased reliability with microgrids that "should come with a different rate." 6 Tr 5202.

In its reply brief, the Staff argues that DTE Electric is currently conducting pilots to investigate microgrids and these existing microgrid pilots should be concluded before instituting new microgrids as the Staff "acknowledges the problems that are caused when microgrids move from utility ownership to third party ownership." Staff's reply brief, p. 17; *see also*, 6 Tr 5203. Second, the Staff reiterates that microgrids should not include fossil generation as such are contrary to Michigan's greenhouse gas emissions net zero goal. Staff's reply brief, pp. 17-18. Third, the Staff argues that because DTE Electric's rate book already has several tariffs that can apply to microgrids, there is no need for a new microgrid tariff. *Id*., p. 18. Finally, in agreement with the company, the Staff reiterates that microgrid users should pay the costs of their microgrid service. *Id*., p. 19.

In its reply brief, GLREA reiterates its claim that microgrids would help address DTE Electric's outages, increasing reliability and resilience. GLREA's reply brief, p. 9. GLREA also argued that without instituting microgrids, DTE Electric's "century old approach" continues to hold its residential customers "wholly captive" to the company's monopoly business model. *Id*. Alternatively, by providing service for customers to "at least partially contribute to self-generation[,]" DTE Electric would be increasing the affordability and reliability of its service while mitigating outages. *Id*., pp. 9-10. Furthermore, GLREA agrees with the CEOs that DTE Electric should be encouraged to implement solutions to increase reliability such as microgrids to alleviate grid strain and that implementing microgrids would stabilize the grid both "locally and as a whole" and thus, GLREA supports creation of customer-owned microgrids, including "sustainably powered individual users all the way up to utility generation of power." *Id*., pp. 10-11. However, GLREA states that microgrid compensation should be based upon the Commission's rates and tariffs dependent upon a microgrid's size and generation capacity. *Id*., p. 11. Lastly, GLREA claims that microgrids can lower power costs and rates, increasing reliability, by allowing a small group of customers to "combine their usage as a group" and "connect to the larger grid behind one meter" to be classified as a larger user, thus qualifying for lower rates. *Id*.

In their initial brief, the CEOs state that they believe that DTE Electric "must look beyond traditional-only upgrades and toward non-conventional solutions." CEOs' initial brief, p. 19. The CEOs further state that their vision of the "grid of the future" involves a decentralized grid that reduces peak load and alleviates the strain on the grid. *Id*. The CEOs' witness, Mr. Volkmann, provided five types of "non-conventional solutions" with the fourth being the use of microgrids that work "as a single controllable entity with respect to the grid." CEOs' initial brief, pp. 19-20; *see also*, 6 Tr 3256. The CEOs assert that DTE Electric "must engage with third-party aggregators and customer-owned equipment in order to maximize the impact that non-conventional solutions can have on the grid" such that the Commission should order the company to implement a pilot to investigate using third-party aggregators and implement a pilot for such. CEOs' initial brief, p. 21.

The Commission finds that there are numerous benefits to microgrids and nanogrids, as well as to the other "non-conventional solutions" proposed by the GLREA, the DAAOs, and the CEOs. However, the Commission notes that there are ongoing pilot projects to investigate the use of microgrids and agrees with the Staff that these pilots should be concluded before initiating additional pathways to microgrid deployment. The Commission also acknowledges DTE Electric's current tariffs that can apply to microgrids and that results from DTE Electric's existing microgrid pilot should inform any new tariffs applicable to microgrids that may be proposed in the future. The Commission also broadly agrees with the Staff that microgrid users should pay for their use of the system, including costs of microgrid service, while acknowledging the arguments put forward by GLREA, the DAAOs, and the CEOs that there may be broad system benefits to microgrid deployment that should be considered in any microgrid cost of service study. As microgrids can lower power costs and have the potential to lower rates while improving reliability, DTE Electric should focus on continued institution of its microgrids, being prepared to increase the availability of such resources after its current pilots are concluded if beneficial to customers.

F. Community Coordination

DTE Electric acknowledges the requirement set forth in Case No. U-21297 that it "'demonstrate its efforts to improve communication and coordination with local governments regarding construction activities . . . .'" DTE Electric's initial brief, p. 337 (quoting December 1 order, p. 375). The company states that, in compliance with the December 1 order, when it is ready to begin a capital project, it "coordinates with the appropriate municipal personnel to set up a brief meeting to discuss the details of the project, benefits, and collaboration opportunities of the work." DTE Electric's initial brief, p. 337; 3 Tr 394. By doing so, both DTE Electric and the corresponding municipality have "some assurance that the planned project does not conflict with a municipal project, whether it's in the conceptual or planned stage." 3 Tr 394. The company also states that it provides periodic updates and meetings to "work through any questions that arise" and that it "is working to improve the frequency of updates to municipalities" along with working with county road commissions to avoid potential conflicts. 3 Tr 394.

In its initial brief, MI-MAUI criticizes DTE Electric for communicating with a local municipality only "'once a DTE project is selected to move forward,'" as such is not done until after capital has been committed to a project. MI-MAUI's initial brief, pp. 1-2 (citing 6 Tr 4362; Exhibit MAU-37). MI-MAUI's witness identified three ways DTE Electric did not meet the Commission's directive in Case No. U-21297:

1) It was too cursory to qualify as a "demonstration of efforts";

2) It did not describe “improvements” in coordination (and described no effort to consult at the beginning of prioritization and planning processes, instead of after those processes had concluded and projects scheduled); and

3) It failed to see any potential financial benefit beyond “conflict avoidance.”

MI-MAUI’s initial brief, p. 2; 6 Tr 4357-4358. Meanwhile, MI-MAUI states that knowing relevant project information such as the “‘when’, ‘where’, and ‘what’ of project planning . . . could help inform a utility about potential project coordination opportunities.” MI-MAUI’s initial brief, p. 2; 6 Tr 4362. MI-MAUI asks that the Commission state that “it will presume that 10% of the costs of electric infrastructure projects that involve excavation in the public right of way or easements are not recoverable unless the [c]ompany can show neither DTE Gas nor the government plans potential work in the same area, or that the [c]ompany made reasonable attempts to coordinate work with such projects.” MI-MAUI’s initial brief, p. 3 (quoting 6 Tr 7364).

DTE Electric disagrees with MI-MAUI’s testimony that “the Commission should ‘presume that 10% of the costs of electric infrastructure projects that involve excavation . . . are not recoverable’” unless the company can prove that neither the local government nor DTE Gas plans to work in the same area, or that DTE Electric made “‘reasonable attempts to coordinate work with such projects.’” DTE Electric’s initial brief, p. 338 (quoting 6 Tr 4363-4364). DTE Electric asserts that its work “might need to be done sequentially and might not be able to be aligned perfectly with the municipality” along with short project timelines and unexpected circumstances causing issues that may not allow for coordination. DTE Electric’s initial brief, p. 339.

In its reply brief, DTE Electric also disagrees with Ann Arbor’s complaints regarding communication with local governments, stating that it provided evidence that, per the Commission’s order in Case No. U-21297, it has improved communication and coordination with local governments. DTE Electric’s reply brief, p. 145. As it did with MI-MAUI, DTE Electric also asserts that there are potential issues which may make it impossible to coordinate with local authority. *Id*., p. 146.

In its reply brief, MI-MAUI chastises DTE Electric for providing a list of why it might not be able to coordinate with local governments. *See*, MI-MAUI's reply brief, p. 1. MI-MAUI states that since DTE Electric seems reliant upon its excuses, the Commission must make it clear that "if DTE [Electric] fails to do the reasonable and demonstrably easy thing – namely *checking* for coordination opportunities before scheduling projects – it should be the [c]ompany, and not the ratepayers, who pay the price of such omissions." *Id*., pp. 1-2 (emphasis in original).

Ann Arbor also addressed this issue with its witness, Dr. Stults, asserting that "DTE [Electric] did not include a demonstration of such efforts in its application and direct testimony" while pointing out that MI-MAUI's witness noticed the same thing. Ann Arbor's initial brief, p. 29. Ann Arbor's witness, Ms. Stewart, testifies that Ann Arbor "believe[s] that coordinating projects whenever possible is the most efficient use of staff time, which results in cost savings for taxpayers and ratepayers of the City's utility services. It also limits disruption residents experience from the work." 6 Tr 4237. Ms. Stewart also testifies that Ann Arbor has a publicly available document that provides its six-year plan for public infrastructure projects which DTE Electric can access. *See*, 6 Tr 4237-4238. However, Ms. Stewart testifies, DTE Electric admitted in Exhibit AA-13 that it "does not routinely review [Ann Arbor's public document] to identify projects that might be coordinated." 6 Tr 4238. Ms. Stewart did admit that DTE Electric has been better about sharing its plans of anticipated projects for the next year, but it is usually a late stage notice that "is not conducive to meaningful coordination or collaboration." 6 Tr 4238-4239. Ms. Stewart mentioned that receiving notice earlier would be beneficial to Ann Arbor "to avoid the cost and disruption of digging up and restoring the right of way multiple times." 6 Tr 4239. Thus, Ann Arbor requests that the Commission "provide a more explicit directive requiring DTE to coordinate in an effort to prevent ratepayers from bearing needlessly duplicative, easily avoidable costs by involving local governments earlier in DTE's planning process." Ann Arbor's initial brief, p. 32. Ann Arbor feels that if DTE Electric were warned that its cost recovery may be reduced in future rate cases, it may work harder at community coordination.

As MI-MAUI did in its reply brief, Ann Arbor chastises DTE Electric's reasons for why it might not be able to coordinate work with local governments. *See*, Ann Arbor's initial brief, pp. 5-7. Ann Arbor acknowledges the legitimacy of DTE Electric's reasonings but insists that it "should try to coordinate as much work as possible with local governments, as well as other utilities, to maximize potential cost savings." *Id.*, p. 6. Furthermore, Ann Arbor points again to publicly available information that DTE Electric could access, thus reiterating that the Commission should require DTE Electric to take such "minimal and reasonable coordination activity for all of its pre-planned underground projects in order to receive full recovery for those projects." *Id.*, pp. 6-7.

The Commission agrees with Ann Arbor that coordinating projects whenever possible results in cost savings while limiting utility disruption for customers. 6 Tr 4237. Thus, DTE Electric should act to coordinate as much as feasible with local governments and other utilities which will result in cost savings and a lower level of utility disruption for its customers. Ann Arbor's initial brief, p. 6. As such, DTE Electric should provide the "'when,' 'where,' and 'what' of its projects which could lead to potential project coordination opportunities." MI-MAUI's initial brief, p. 2; 6 Tr 4362. Consistent with MI-MAUI's suggestion, the Commission encourages DTE Electric to properly notify other utilities and municipalities once a project is selected to move forward, not waiting until capital has been committed to a project. MI-MAUI's initial brief, p. 2 (internal citations omitted). However, the Commission declines to endorse a 10% disallowance on capital projects as motivation. The Commission will continue to review the specifics of proposed capital expenditures in future rate case proceedings, including efforts to coordinate with local governments and other utilities, where appropriate.

G. Tracking and Reports

In the Staff's initial brief, it stated that the Commission should direct the Staff to continue the recommendation found as Recommendation 2.1 in Case No. U-20757 "to combine the monthly Shutoff and Arrearage report and the Quarterly report and have this submitted on a quarterly basis." December 21, 2023 order (December 21 order) in Case No. U-20757, pp. 21-22. By combining the monthly shutoff and arrearage report and the quarterly report, the Staff removes unnecessary data points and streamlines the reporting process. Additionally, the Staff acknowledged that the Commission has ordered it to "continue to move towards zip code and census track level data" per Recommendation 2.6 in the December 21 order. To comply with this directive, the Staff is currently discussing how to obtain shut off and arrearage data per Recommendation 2.6 in the December 21 order. Furthermore, the Staff suggests that the Commission direct it to continue making shutoff and arrearage data in an easily accessible format that is publicly available on the Commission's website. Staff's initial brief, p. 157.

The Commission agrees with the Staff's suggestion to direct the Staff to continue providing shutoff and arrearage data in an easily accessible format, publicly available on the Commission's website.

As mentioned *supra*, further information on future opportunities for interested parties to collaborate in this process will be provided on the Commission's webpage and through the New Technologies and Business Models listserv. The Commission notes that the Staff is also working on the development of a spreadsheet-based or similar open-source tool as a model for the required benefit-cost analysis that accompanies requests for pilots, to be ready for use in 2026, which may include non-energy benefits, as discussed in the November 21, 2024 order in Case No. U-20898.

H. Affordability Assessments and Measures

a. Affordability Definition

The DAAOs state that the Commission "has defined energy affordability as '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 a household's ability to meet other basic needs.'" DAAOs' initial brief, pp. 12-13 (quoting December 21, 2023 order in Case No. U-20757 (December 21 order), p. 36). The DAAOs opine, however, that DTE Electric "has not incorporated that definition into its analysis, requests, investments, or plans." DAAOs' initial brief, p. 13. As such, the DAAOs contend that the Commission "should require that DTE Electric adopt and uniformly use the Commission's definition of affordability, set energy-burden based goals to improve the company's unaffordable rates, and refrain from using the term in the incoherent manner that has been the company's practice." 6 Tr 4392-4393.

In the December 21 order, the Commission stated that "rates are to be set to ensure the recovery of a utility's revenue requirement and in a manner that allows utilities to continue to provide the services necessary for its customers. The Commission also acknowledges that certain customers have challenges with the affordability of those services." December 21 order, p. 36. Accordingly, the Commission adopted a definition for "affordability" to "help in the development of assistance programs and strategies to ensure that customers struggling with utility bills have the resources necessary to afford these essential services." *Id.*, pp. 36-37. The Commission finds that it is important that utilities, including DTE Electric, use the definition of affordability approved in the December 21 order to ensure that the Commission may properly consider and decide issues regarding high energy burdens experienced by low-income and vulnerable customers pursuant to the directives of Public Act 231 of 2023. As such, the 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. However, the Commission also acknowledges that the definition of "affordability" may evolve in future orders; until the definition of "affordability" has changed, the definition set forth in the December 21 order will continue to be utilized.

b. Energy Equity Framework and Shutoff Moratorium

The DAAOs discuss procedural equity and distributive equity. Procedural equity "is concerned with program access," whereas distributive equity "refers to how the benefits and harms of the energy system are distributed, and is closely aligned with the notion of 'justice as fairness . . . .'" 6 Tr 4465, 4467. Regarding procedural equity, Witness Schott explains that there are a limited number of available slots in DTE Electric's assistance programs and argues that the company does not actively work to help customers enroll in their assistance programs. Regarding distributive equity, Witness Schott asserts that BIPOC communities are more likely to be exposed to environmental harms such as toxic pollution while being less likely to have access to positive environmental goods such as parks and green spaces. 6 Tr 4467. Witness Schott testifies that "DTE Electric resists the use of appropriate metrics that would reveal and could help mitigate distributive inequities." 6 Tr 4468.

The DAAOs conclude by discussing restorative justice, i.e., the mitigation of conditions that initially caused harm or disparate impacts to prevent future harm. 6 Tr 4471. The DAAOs criticize DTE Electric, stating that “concerns with DTE Electric’s performance and steady rate increases are widely known, [however] the [c]ompany does not face consequences for providing service that is neither reliable nor affordable.” 6 Tr 4471. The DAAOs argue that there are no rules or financial penalties if DTE Electric causes harms more often to BIPOC or low-income households “through aggressive shutoff and collections practices or dismal electric reliability performance.” 6 Tr 4471. The DAAOs argue that these practices “perpetuate and exacerbate the harms” that low-income communities have faced, impeding efforts to mitigate future harms. 6 Tr 4471.

The DAAOs recommend a systematic approach to reducing shutoffs that includes five steps: (1) “[e]nacting an immediate moratorium on all shutoffs not related to theft or unauthorized use . . . [;]” (2) “[d]efining measures of success, namely a reduction in shutoffs and a reduction in the number of customers with energy burdens above 6%[;]” (3) “[p]roposing a comprehensive affordability strategy[;]” (4) “[c]reating a unified affordability program that reduces customer arrearages and enables customers to afford their bills, ideally a PIPP that ensures no customer spends more than 3% of income on electricity and no more than 6% on energy in total[;]” and (5) “[c]reating systems that prioritize outreach, enrollment, and program evaluations . . . .” 6 Tr 4505-4506.

As discussed *supra*, in response to the DAAOs’ request that the company create a PIPP, the Commission notes that utility PIPP pilots are currently being evaluated, alongside other affordability and assistance programs, by the AAA subcommittee of the EAAC, which will help determine next steps.

The DAAOs further highlight the impact of shutoffs in the community, stating that shutoffs can have various negative health impacts, “including heat stress during warmer temperatures, and exacerbation of chronic illnesses, particularly those with cardiovascular, respiratory, and/or renal diseases." DAAOs' initial brief, p. 12.

The DAAOs suggest that the Commission immediately pause shutoffs while the Commission collects more information and that the Commission adopt "an extended moratorium on shutoffs if the analysis of this forthcoming data identifies entrenched inequities, insufficient affordability programs, or a sustained risk to public health." 6 Tr 4518. The DAAOs state that included in the moratorium would be "associated customer protections against late fees, additional deposits, and reconnection fees" as those cause "immediate and disproportionate harm" to BIPOC and low-income households. 6 Tr 4519. The DAAOs' witness, Mr. Schott, also testifies that the Commission has authority "to provide immediate relief to the most vulnerable customers and those with the lowest incomes" and that the Commission has an existing plan to do such through its orders in the COVID-19 docket in Case No. U-20757. 6 Tr 4517.

DTE Electric disagrees that late fees, deposits, and reconnection fees should be withheld because these "are assessments and not necessarily what was collected by the [c]ompany." 6 Tr 2396. The company further states that its energy assistance "is equitable in that any income qualified households can access such assistance . . . ." 6 Tr 2396.

The Commission acknowledges the points made by the DAAOs in their effort to improve energy affordability and lessen the disproportionate impacts on BIPOC and low-income households. However, the Commission finds that a rate case proceeding is not the appropriate forum to consider moratoria on shutoffs and disconnections, and therefore declines to adopt the DAAOs' moratorium proposal. The Commission remains committed to considering opportunities to address affordability and equity concerns in a holistic manner through the EAAC and other venues.

I. Tariff Corrections

The Staff recommended several spelling and punctuation corrections to the company's tariffs. 6 Tr 4899; Exhibit S-6, Schedule F8; Staff's initial brief, p. 128. No party rebutted the recommendations or replied to the Staff's initial brief on this issue. The Commission approves the tariff corrections presented in Exhibit S-6, Schedule F8.

THEREFORE, IT IS ORDERED that:

A. Based on the findings in this order adopting a January 1, 2025 through December 31, 2025 test year, a jurisdictional rate base of $21,787,037,000, an authorized rate of return on common equity of 9.90%, and an authorized required rate of return of 5.69%, DTE Electric Company is authorized to implement rates that increase its annual electric revenues by $217,380,000, on a jurisdictional basis, over the rates approved in the December 1, 2023 order in Case No. U-21297.

B. DTE Electric Company is authorized to implement rates consistent with the revenue deficiency approved by this order on a service rendered basis for service provided on and after February 6, 2025, as reflected in Attachment A (a summary of revenue by rate class), Attachment B (tariff sheets), and Attachment C (updated calculation of the capacity charge) to this order. Within 30 days of the date of this order, DTE Electric Company shall file tariff sheets substantially similar to Attachment B. When filing the tariffs consistent with those ordered, DTE Electric Company shall also update the Standard Allowance amounts on Tariff Sheet C-30.00, Section C6.2(4)(a), to be consistent with the rates approved in this order. After the tariff sheets have been reviewed and accepted by the Commission Staff for inclusion in the company's tariff book, DTE Electric Company shall promptly file the final tariff sheets in this docket and serve all parties. DTE Electric Company shall implement a state reliability mechanism capacity charge of $84,136 per megawatt-year, or $230.51 per megawatt-day, for customers taking capacity service, as shown on Attachment C to this order. Attachment B contains the associated capacity rates.

C. In its next rate case, DTE Electric Company shall present a comprehensive plan for the removal of all remaining arc wire, as set forth in this order.

D. DTE Electric Company shall provide detailed status and expenditure updates on the company's expenditures for the Error Free Communications program demonstrating the results of any investments in the program in future rate cases.

E. DTE Electric Company shall meet with the Commission Staff in the form of biannual meetings to provide detailed status updates on any continuous improvements, as well as failures, in the Error Free Communications program and its various components.

F. The Commission Staff shall conduct a technical workshop with DTE Electric Company; Michigan Municipal Association for Utility Issues; pertinent roadway luminaire manufacturers, vendors, and/or engineers; Consumers Energy Company; and other interested persons to evaluate and explore the following: (1) the practicality and cost effectiveness of performing conversion projects that comply with relevant American National Standards Institute/Illuminating Engineering Society standards, as opposed to merely matching the lumen output of original high-intensity discharge and high-pressure sodium luminaires; (2) comparing and contrasting the light-emitting diode luminaire selection methodologies of DTE Electric Company and Consumers Energy Company; (3) determining appropriate recommended light-emitting diode luminaires for conversion projects; and (4) determining appropriate methods for conducting meaningful discussions with customers regarding recommended light-emitting diode luminaires for conversion projects.

G. In its next demand response reconciliation case, DTE Electric Company shall expand the company's cost effectiveness analysis to all demand response programs, including interruptible rates.

H. DTE Electric Company is directed to provide detailed information sufficient to differentiate the benefits of membership in the Center for Energy Workforce, the Human Capital Institute, and The Institute for Corporate Productivity in its next general rate case to avoid duplication of services and benefits.

I. DTE Electric Company is directed to provide in its next general rate case a discussion of the actual processes, projects, procedures, or other tangible impacts benefitting the company's customers that have resulted from nondiscretionary corporate memberships.

J. DTE Electric Company is authorized to extend its investment recovery mechanism through December 31, 2026, as described in this order. DTE Electric Company shall submit its 2026 investment recovery mechanism plan no later than four months prior to the start of the 2026 investment recovery mechanism year; submit a copy of its plan to all intervening parties in the company's most recently filed general rate case, including the Commission Staff; and schedule and provide a forum, no later than two months prior to the start of the 2026 investment recovery mechanism year, for the Commission Staff and intervening parties to raise any questions or concerns before execution of the investment recovery mechanism plan begins.

K. DTE Electric Company shall propose in its next general rate case, in consultation with the Commission Staff and other interested parties, tariff language to modify its current Tariff C-27.00, using Consumers Energy Company's Tariff D-14.00 as guidance. Additionally, in its next general rate case, DTE Electric Company shall propose, in consultation with the Commission Staff and other interested parties, tariff language to modify its current Tariff C-27.00 to include a limited contribution-in-aid-of-construction waiver related to the difference in costs associated with customers connected at 4.8 kilovolts and those connected at 13.2 kilovolts.

L. DTE Electric Company shall provide 8760-hour annual load profiles for electric vehicles in its next Electric Vehicle Annual Status Report.

M. DTE Electric Company shall provide, in its next general rate case, a list of the federal electric vehicle programs the company has directly applied for and been awarded.

N. DTE Electric Company must report in its next Electric Vehicle Annual Status Report or general rate case the number of low-income residential electric vehicle charger installation rebates that have been disbursed.

O. DTE Electric Company shall provide an update on the status of its School Bus Charger program in its next Electric Vehicle Annual Status Report.

P. DTE Electric Company shall, in its next general rate case, investigate and analyze whether it will be beneficial to offer a charger output capacity tier-based rebate approach similar to the existing Charging Forward eFleets Charger Rebates.

Q. DTE Electric Company shall provide in its next Electric Vehicle Annual Status Report a detailed explanation of the progress of the Charging Hubs pilot project.

R. DTE Electric Company shall continue to provide an annual update on Emerging Technology pilots and learnings in its Electric Vehicle Annual Status Report.

S. DTE Electric Company and the Commission Staff shall collaborate to develop a procedure for limited recovery of outage credits, as described above, and the company shall defer the costs for review and recovery to a future general rate case using account 182.3, Other Regulatory Assets.

T. DTE Electric Company shall include in its next general rate case, in relation to the transition from Rate Schedule D1.6 to Rate Schedule D1.11, an analysis of shutoff information, an analysis of the factors impacting household ability to shift usage, and regression analyses.

U. DTE Electric Company shall revise and implement Rate Schedule D3.11 by June 1, 2025, without a cap on enrollment as specified in this order.

V. DTE Electric Company's existing "demand charge holiday" is extended through June 2028.

W. DTE Electric Company shall collaborate with the Commission Staff and interested persons to develop and file in a new docket, no later than 5:00 p.m. (Eastern time) on December 1, 2026, an optional successor electric vehicle fast charger rate to Rate Schedule D3 which will be available to electric vehicle fast charging customers when Rate Schedule D3 is no longer available to direct current fast chargers.

X. DTE Electric Company shall consult with the Commission Staff and intervenors to develop a proposed per-lamp bill credit for early LED adopter municipalities which must be applied for by December 31, 2025.

Y. DTE Electric Company shall incorporate the Commission Staff's low-income verification form as approved in Case No. U-20917.

Z. DTE Electric Company shall take proactive measures to inform municipalities and other utilities of projects it plans to commence prior to earmarking capital for the project.

AA. DTE Electric Company shall take proactive measures to investigate publicly available plans provided by other utilities and municipalities in an effort to coordinate work.

BB. The Commission Staff shall continue work regarding the collection of shutoff and arrearage data to include data by census tract and zip code.

CC. DTE Electric Company shall use the definition of "affordability" as approved in the December 21, 2023 order in Case No. U-20757 for any analyses it presents to the Commission when referencing affordability impacts of energy-assistance programs in contested cases.

DD. DTE Electric Company's Rate Schedule D14 time-of-use rate is approved without a cap on the number of customers or total contract demand.

EE. In its next rate case, DTE Electric Company shall propose a revenue-neutral modification to Rate Schedule D14 with an on-peak window of time that is sufficiently shorter than eight hours, following consultation with interested persons.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Alessandra R. Carreon, Commissioner

By its action of January 23, 2025.

Lisa Felice, Executive Secretary

DTE Electric Company
Case No. U-21534
Order Summary of
Present and Proposed Revenue
FOR ORDER

Total Revenues

	(a)	(b)	(c)	(d)	(e)
Line No.	**Residential**	**Total Present Revenue ($000's)**	**Total Proposed Revenue ($000's)**	**Total Net Increase/ (Decrease) ($000's)**	**Total Net Increase/ (Decrease) (%)**
1	D1/D1.6 Residential	$48,113	$47,332	($781)	(1.6%)
2	D1.1 Int. Air	$53,003	$55,859	$2,855	5.4%
3	D1.2 TOD	$32,651	$34,396	$1,745	5.3%
4	D1.7 TOD	$15,366	$16,301	$935	6.1%
5	D1.8 Dynamic	$29,305	$30,799	$1,494	5.1%
6	D1.9 Elec. Vehicle	$1,992	$2,102	$110	5.5%
7	D1.11 Time of Use	$2,635,170	$2,761,540	$126,370	4.8%
8	D2 Elec. Space Heat	$47,106	$49,631	$2,525	5.4%
9	D5 Res. Water Ht.	$14,146	$14,975	$830	5.9%
10	Total Residential	$2,876,853	$3,012,936	$136,083	4.7%
11					
12	**Secondary**				
13	D1.1 Int. Air	$708	$741	$33	4.6%
14	D1.7 TOD	$1,581	$1,676	$95	6.0%
15	D1.8 Dynamic	$136	$142	$6	4.6%
16	D 1.9 Elec Vehicle	$62	$65	$3	5.0%
17	D3 Gen. Serv.	$1,066,344	$1,115,594	$49,250	4.6%
18	D3.1 Unmetered	$11,064	$11,699	$635	5.7%
19	D3.2 Sec. Educ.	$60,733	$64,427	$3,694	6.1%
20	D3.3 Interruptible	$7,083	$7,469	$386	5.4%
21	D3.5 Charging Serv.	$0	$0	$0	-
22	D4 Lg. Gen. Serv.	$256,631	$267,880	$11,249	4.4%
23	D5 Com. Wat. Ht.	$1,085	$1,146	$60	5.6%
24	E1.1 Eng. St. Ltg.	$1,152	$1,215	$63	5.5%
25	R7 Greenhs. Ltg.	$419	$444	$25	6.1%
26	R8 Space Cond.	$9,537	$10,007	$471	4.9%
27	Total Secondary	$1,416,535	$1,482,505	$65,970	4.7%
28					
29	**Primary**				
30	D11 Prim. Supply	$959,228	$966,497	$7,269	0.8%
31	D12 Exp. Lrg Cust	$0	$0	$0	-
32	D6.2 Pri. Educ.	$74,835	$79,324	$4,490	6.0%
33	D8 Int. Primary	$39,805	$40,054	$249	0.6%
34	D10 El.Schools	$2,911	$2,887	($25)	(0.8%)
35	R1.1 Alt. Mtl. Melt.	$8,244	$8,375	$131	1.6%
36	R1.2 El. Pr. Htg.	$30,125	$30,425	$300	1.0%
37	R3 Standby	$8,526	$8,494	($32)	(0.4%)
38	R10 Int. Supply	$52,885	$53,201	$316	0.6%
39	Total Primary	$1,176,559	$1,189,257	$12,698	1.1%
40					
41	D13 XL	$11,111	$10,861	($251)	(2.3%)
42					
43	**Other**				
44	D9 Protective Ltg.	$12,439	$12,761	$322	2.6%
45	E1 Muni Street Ltg	$63,859	$66,215	$2,356	3.7%
46	E2 Traffic Lights	$5,468	$5,666	$199	3.6%
47	Total Other	$81,766	$84,643	$2,877	3.5%
48					
49	**Total All Classes**	$5,562,824	$5,780,202	$217,379	3.9%

Power Supply Revenues

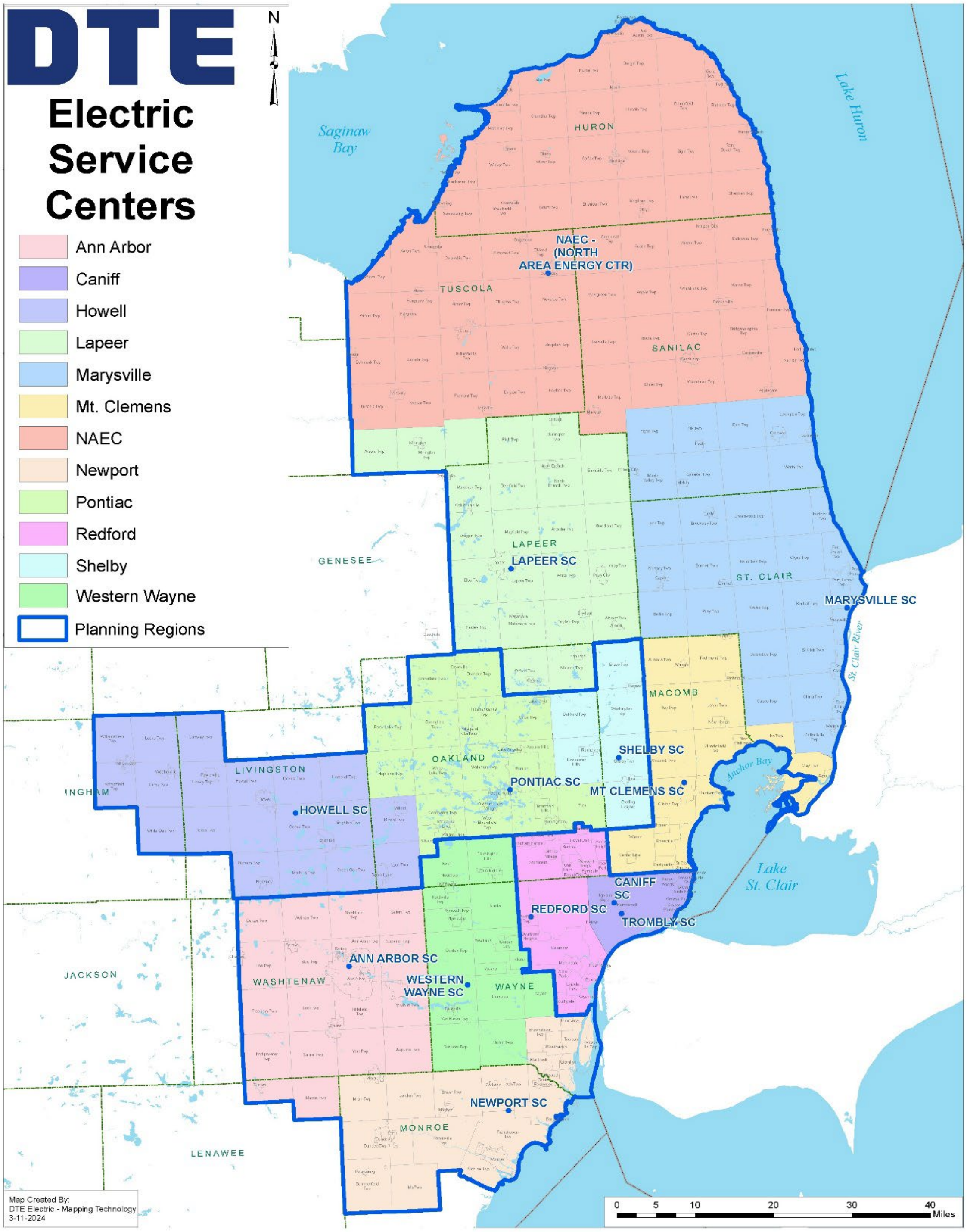
Line No.	(a) Residential	(b) Power Supply Sales (MWH)	(c) Present Revenue ($000's)	(d) Increase/ (Decrease) ($000's)	(e) Proposed Revenue ($000's)	(f) Capacity Revenue ($000's)	(g) Non-Capacity Revenue ($000's)
1	D1/D1.6 Residential	332,538	$30,327	$498	$30,824	$12,019	$18,805
2	D1.1 Int. Air	321,827	$22,915	$376	$23,291	$9,082	$14,209
3	D1.2 TOD	196,822	$14,282	$229	$14,511	$4,334	$10,177
4	D1.7 TOD	108,929	$5,827	$96	$5,922	$2,309	$3,613
5	D1.8 Dynamic	166,773	$12,765	$209	$12,974	$5,059	$7,915
6	D1.9 Elec. Vehicle	12,539	$801	$13	$814	$317	$496
7	D1.11 Time of Use	13,748,482	$1,246,609	$20,452	$1,267,061	$494,067	$772,994
8	D2 Elec. Space Heat	282,672	$19,648	$347	$19,995	$5,397	$14,598
9	D5 Res. Water Ht.	97,669	$4,717	$77	$4,795	$1,870	$2,925
10	Total Residential	15,268,251	$1,357,891	$22,296	$1,380,188	$534,456	$845,732
11							
12	**Secondary**						
13	D1.1 Int. Air	5,153	$358	$3	$361	$122	$239
14	D1.7 TOD	15,388	$714	$6	$720	$243	$477
15	D1.8 Dynamic	972	$77	$1	$77	$26	$51
16	D1.9 Elec. Vehicle	342	$28	$0	$29	$11	$17
17	D3 Gen. Serv.	7,457,882	$604,536	$5,217	$609,753	$206,058	$403,695
18	D3.1 Unmetered	89,133	$6,141	$53	$6,194	$2,093	$4,101
19	D3.2 Sec. Educ.	331,944	$26,144	$107	$26,251	$8,542	$17,709
20	D3.3 Interruptible	54,552	$3,695	$32	$3,727	$1,259	$2,467
21	D3.5 Charging Serv.	0	$0	$0	$0	$0	$0
22	D4 Lg. Gen. Serv.	1,738,514	$131,658	$592	$132,250	$41,073	$91,177
23	D5 Com. Wat. Ht.	9,881	$472	$4	$476	$161	$315
24	E1.1 Eng. St. Ltg.	10,256	$573	$5	$578	$195	$382
25	R7 Greenhs. Ltg.	4,153	$192	$2	$194	$66	$128
26	R8 Space Cond.	73,342	$5,164	$45	$5,209	$1,760	$3,449
27	Total Secondary	9,791,512	$779,751	$6,066	$785,817	$261,610	$524,206
28							
29	**Primary**						
30	D11 Prim. Supply	11,505,383	$754,111	$3,914	$758,025	$205,925	$552,100
31	D12 Exp. Lrg Cust	0	$0	$0	$0	$0	$0.00
32	D6.2 Pri. Educ.	699,018	$50,619	$4,280	$54,899	$18,595	$36,304
33	D8 Int. Primary	509,730	$29,445	$90	$29,535	$5,491	$24,044
34	D10 El.Schools	20,890	$1,710	$9	$1,719	$467	$1,252
35	R1.1 Alt. Mtl. Melt.	125,163	$6,971	$9	$6,981	$1,073	$5,908
36	R1.2 El. Pr. Htg.	347,461	$19,281	($98)	$19,183	$2,783	$16,400
37	R3 Standby	74,189	$5,880	$24	$5,904	$1,630	$4,274
38	R10 Int. Supply	998,081	$47,740	$19	$47,759	$0	$47,759
39	Total Primary	14,279,913	$915,758	$8,246	$924,004	$235,963	$688,041
40							
41	D13 XL	200,000	$10,496	($278)	$10,218	$3,028	$7,190
42							
43	**Other**						
44	D9 Protective Ltg.	33,226	$1,482	$49	$1,531	$0	$1,531
45	E1 Muni Street Ltg	123,056	$5,488	$180	$5,669	$0	$5,669
46	E2 Traffic Lights	59,731	$3,817	$32	$3,849	$913	$2,937
47	Total Other	216,013	$10,787	$261	$11,048	$913	$10,136
48							
49	**Total All Classes**	39,755,689	$3,074,683	$36,593	$3,111,275	$1,035,970	$2,075,305

Distribution Revenues

Line No.	(a) Residential	(b) Distribution Sales (MWH)	(c) Present Revenue ($000's)	(d) Increase/ (Decrease) ($000's)	(e) Proposed Revenue ($000's)
1	D1/D1.6 Residential	332,538	$17,786	($1,278)	$16,508
2	D1.1 Int. Air	321,827	$30,089	$2,479	$32,568
3	D1.2 TOD	196,822	$18,369	$1,516	$19,885
4	D1.7 TOD	108,929	$9,540	$839	$10,379
5	D1.8 Dynamic	166,773	$16,540	$1,285	$17,825
6	D1.9 Elec. Vehicle	12,539	$1,192	$97	$1,288
7	D1.11 Time of Use	13,748,482	$1,388,561	$105,918	$1,494,479
8	D2 Elec. Space Heat	282,672	$27,459	$2,178	$29,636
9	D5 Res. Water Ht.	97,669	$9,428	$752	$10,181
10	Total Residential	15,268,251	$1,518,962	$113,786	$1,632,748
11					
12	**Secondary**				
13	D1.1 Int. Air	5,164	$350	$29	$380
14	D1.7 TOD	15,586	$867	$89	$956
15	D1.8 Dynamic	972	$59	$6	$64
16	D1.9 Elec Vehicle	342	$34	$3	$37
17	D3 Gen. Serv.	7,719,328	$461,808	$44,033	$505,842
18	D3.1 Unmetered	89,133	$4,924	$582	$5,505
19	D3.2 Sec. Educ.	628,745	$34,590	$3,587	$38,176
20	D3.3 Interruptible	62,065	$3,388	$354	$3,742
21	D3.5 Charging Serv.	0	$0	$0	$0
22	D4 Lg. Gen. Serv.	1,993,249	$124,973	$10,658	$135,630
23	D5 Com. Wat. Ht.	9,886	$614	$56	$670
24	E1.1 Eng. St. Ltg.	10,256	$579	$59	$637
25	R7 Greenhs. Ltg.	4,153	$227	$24	$250
26	R8 Space Cond.	74,713	$4,372	$426	$4,798
27	Total Secondary	10,613,593	$636,784	$59,905	$696,689
28					
29	**Primary**				
30	D11 Prim. Supply	14,553,177	$205,117	$3,355	$208,472
31	D12 Exp. Lrg Cust	0	$0	$0	$0
32	D6.2 Pri. Educ.	1,093,792	$24,215	$210	$24,425
33	D8 Int. Primary	642,991	$10,360	$159	$10,519
34	D10 El.Schools	34,286	$1,201	($33)	$1,168
35	R1.1 Alt. Mtl. Melt.	125,163	$1,273	$122	$1,395
36	R1.2 El. Pr. Htg.	369,846	$10,845	$398	$11,242
37	R3 Standby	66,802	$2,646	($56)	$2,590
38	R10 Int. Supply	998,081	$5,145	$297	$5,442
39	Total Primary	17,884,137	$260,801	$4,452	$265,253
40					
41	D13 XL	200,000	$615	$27	$642
42					
43	**Other**				
44	D9 Protective Ltg.	33,226	$10,957	$274	$11,231
45	E1 Muni Street Ltg	123,056	$58,370	$2,176	$60,547
46	E2 Traffic Lights	59,731	$1,651	$166	$1,817
47	Total Other	216,013	$70,979	$2,616	$73,595
48					
49	**Total All Classes**	44,181,994	$2,488,141	$180,786	$2,668,927

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

First Revised Sheet No. A-18.00
Cancels Original Sheet No. A-18.00



Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

(Continued from Sheet No. C-26.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.1 Extension of Service (Contd.)

(13) The applicant shall furnish without cost to the Company, all necessary rights-of-way and line clearance permits in a form satisfactory to the Company. The Company will provide the necessary easement forms, and solicit their execution. The applicant(s), as a condition of service, will be ultimately responsible for obtaining all easements and permits as required by the Company, for construction, operation, maintenance and protection of the facilities to be constructed. Where State or Federal lands are to be crossed to extend service to an applicant or group of applicants, the additional costs incurred by the Company for rights-of-way and permit fees shall be borne by the applicant(s). If the applicant is unable to secure satisfactory easements and/or permits, the Company shall extend its facilities along an alternate route selected by the Company. The applicant will be required to make a non-refundable contribution in aid of construction for all additional costs incurred.

(14) Scheduling of construction shall be done on a basis mutually agreeable to the Company and the applicant. The Company reserves the right not to begin construction until the customer has demonstrated to the Company's satisfaction his intent to proceed in good faith with installation of his facilities by acquiring property ownership, obtaining all necessary permits, starting construction, and/or, in the case of mobile homes, meeting the Company's requirements for permanency.

(15) The Company reserves the right to make the final determination of selection, application, location, routing and design of its facilities. Where excessive construction costs are incurred by the Company at the request of the customer, the customer may be required to make a non-refundable contribution in aid of construction to the Company for such excess costs.

C6.2 Overhead Extension Policy

A Customers on Rates D1 and D2.

(1) Overhead Extension Policy - Application for electric service which requires the construction of an extension to the Overhead System will be granted under the following conditions;

(a) Standard Allowance - For each residence, the Company will construct single-phase distribution line extensions at its own cost a distance of 600 feet, of which no more than 250 feet will be on private property (lateral extension).

If the distribution line is constructed such that it can be available to serve only two premises (joint lot line construction), such extension shall be considered as a lateral extension, and the customer(s) requesting service shall each be granted up to 250 feet of free footage. For purposes of this policy, secondary voltage distribution lines shall not be considered as a line extension.

(Continued on Sheet No. C-28.00)

(Continued from Sheet No. C-27.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.2 Overhead Extension Policy (Contd.)

(b) Charges - Single phase overhead line extensions in excess of the above footage will require a refundable construction advance of $***16.91*** per foot, measured from pole to pole, plus a non-refundable contribution for the estimated line clearance cost for such excess footage. There may also be a non-refundable contribution in aid of construction equal to the cost of securing right of way. Three-phase extensions will be on the same basis as Commercial and Industrial.

(c) Measurement - The length of any extension will be measured along the route of the extension from the Company's nearest facilities from which the extension can be made to the point of connection with the service drop.

Should the Company for its own reasons choose a longer route, the applicant will not be charged for the additional distance, however, if the customer requests special routing of the line, the customer will be required to pay a non-refundable contribution in aid of construction for the extra cost resulting from the special routing.

(d) Refunds - During the five (5) year period immediately following the date the line extension is completed, the Company will make refunds of the refundable construction advance paid for a financed extension under provisions of Paragraph (2) above. The amount of any such refund shall be equal to two (2) times the estimated average annual revenue or $500 (whichever is greater) for each additional standard allowance customer subsequently connected directly to the facilities financed by the original customer. Directly connected residential customers are those which do not require the construction of more than 600 ft. of single phase line extension or 250 feet on private property. Directly connected commercial or industrial customers are those which do not require payment of a refundable construction advance. Such refunds will be made only to the original customer and will not include any amount of non-refundable contribution in aid of construction for underground service made under the provisions of the Company's underground service policy. The refund shall not exceed the total refundable construction advance. The refundable construction advance shall not bear interest.

(2) Underground Extension Policy - The Company will extend its primary or secondary distribution system from existing overhead or underground facilities. When any such extension is made from an existing overhead system the property owner may be required to provide an easement(s) for extension of the overhead system to a pole on his property where transition from overhead to underground can be made.

(Continued on Sheet No. C-29.00)

(Continued from Sheet No. C-33.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.3 Underground Distribution Systems (Contd.)

B Distribution for Residential Subdivisions

(1) General

(a) Distribution facilities in all new residential subdivisions and existing residential subdivisions in which electric distribution facilities have not already been constructed shall be placed underground, except that a lot facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area.

(b) The Company will install an underground distribution system, including primary and secondary cable and all associated equipment, to provide service to the lot line of each lot in the subdivision.

(c) For purposes of definition, all one-family and two-family buildings on individual lots are residential.

(d) The developer of a new residential subdivision shall cause to be recorded with the plat of the subdivision a public utility easement approved by the Company for the entire plat. Such easement shall include a legal description of areas within the plat which are dedicated for utility purposes and also other restrictions as shall be determined by the Company for construction, operation, maintenance and protection of its facilities.

(e) Where sewer lines will parallel Company cables, taps must be extended into each lot for a distance of one (1) foot beyond the easement prior to installation of the cables.

(2) Charges - Prior to commencement of construction, the owner or developer will pay to the Company an amount equal to the estimated cost of construction of the distribution system, but not less than the non-refundable contribution in aid of construction determined by multiplying the sum of the lot front footage for all lots in the subdivision by $***18.30***, except for those lots served by an underground service from an overhead distribution line as previously stated in this rule.

(3) Refunds - The balance of the charges (refundable construction advance) shall be made available to the developer or owner on the following basis:

During the five (5) year period immediately following completion of the distribution construction, the Company will refund two (2) times the estimated average annual revenue or $500 (whichever is greater) for each permanent residential customer connected within the subdivision. Such refunds will be made only to the original developer or owner and in total shall not exceed the refundable construction advance. The refundable construction advance shall bear no interest.

(Continued on Sheet No. C-35.00)

(Continued from Sheet No. C-34.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.3 Underground Distribution Systems (Contd.)

(4) Measurement - The front foot measurement of each lot to be served by a residential underground distribution system will be made along the contour of the front lot line. The front lot line is that line which usually borders on or is adjacent to a street. However, when streets border on more than one side of a lot, the shortest dimension will be used. In case of a curved lot line which borders on a street or streets and represents at least two sides of the lot, the front foot measurement will be considered as one-half the total measurement of the curved lot line. The use of the lot front foot measurement in these rules shall not be construed to require that the underground electric distribution facilities be placed at the front of the lot.

(5) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

(6) Extension of Existing Distribution Systems in Platted Subdivisions - Any such extension shall be considered a distinct, separate unit, and any subsequent extensions therefrom shall be treated separately.

(a) Charge - Prior to commencement of construction the applicant shall make a non-refundable contribution in aid of construction in an amount equal to $***18.30*** per lot front foot for the total front footage of all lots which can be directly served in the future from the distribution system installed to serve the initial applicant. All subsequent applicant(s) for service on these lots shall be required to make a non-refundable contribution in aid of construction in the amount of $***18.30*** per lot front foot for all lots owned by the subsequent applicant(s) which can be directly served from the original distribution extension.

(b) Refunds - The Company will refund to the original applicant the amounts contributed in aid of construction by subsequent applicants as provided in Paragraph 1 above. The total amount refunded shall not exceed the amount of the original contribution, and will be made only to the original applicant. The Company will endeavor to maintain records for such purposes but the original applicant is ultimately responsible to duly notify the Company of refunds due; any refund not claimed within five (5) years after the date of completion of distribution constructions shall be forfeited. Refunds made under the provisions of this paragraph shall be in addition to refunds made under the Company's overhead line extension policy.

(c) Measurements - The lot front footage used in computing charges and contributions in Paragraph 1 above shall be measured the same as for new subdivisions.

(d) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

(Continued on Sheet No. C-36.00)

(Continued from Sheet No. C-35.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.3 Underground Distribution Systems (Contd.)

C Distribution for Mobile Home Parks

(1) General

(a) For purposes of this rule, the definition of a mobile home park is a parcel or tract of land under the control of a person(s) upon which three or more mobile homes are located on a continual non-recreational basis not intended for use as a temporary trailer park.

(b) Distribution facilities in new mobile home parks shall be placed underground. Extension from existing overhead systems in mobile home parks will be placed underground at the option of the park owner.

(c) This service is limited to mobile home parks in which the service is metered by the Company at secondary voltage.

(d) Company cables shall be separated by at least five feet from paralleling underground facilities which do not share the same trench. The park owner's cable systems, such as community antenna systems, should be in separate trenches, if possible. Subject to an agreement with the Company these cable systems may occupy the same trench. The park owner must agree to pay a share of the trenching cost plus the extra cost of the additional backfill, if required, and agree to notify the other using utilities when maintenance of his cable requires digging in the easement.

(e) The park owner must provide for each mobile home lot a meter pedestal of a design acceptable to the Company.

(2) Charges - The park owner shall be required to make a non-refundable contribution in aid of construction as follows:

(a) Prior to commencement of construction, the owner or developer will pay to the Company an amount equal to the estimated cost of construction of the distribution system, but not less than the non-refundable contribution in aid of construction determined by multiplying the sum of the lot front footage for all lots in the park by $***18.30***, except for those lots served by an underground service from an overhead distribution line as previously stated in this rule.

(b) <u>Service Loops or Laterals</u> - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

(c) <u>Transformers</u> - $***18.47*** per kVA, for the total nameplate kVA installed.

(Continued on Sheet No. C-37.00)

(Continued from Sheet No. C-36.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.3 Underground Distribution Systems (Contd.)

(d) Measurements - The lot front footage used in computing charges and contributions shall be measured the same as for new subdivisions.

D Distribution for Condominiums and Apartment House Complexes

(1) This service is limited to multiple occupancy buildings in which service is metered by the Company at secondary voltage. These include, but are not limited to, low-rise apartments, townhouses, condominiums and cluster housing where space is available for pad-mounted transformers and other above-grade equipment and the area is suitable for the direct burial installation of cable. Where the developer and/or the Company are concerned that the easement area could be developed with patios, etc., special facilities such as conduit may be required to allow the Company to maintain the system. If special facilities are required, the developer will be responsible for providing them.

(2) Charges

(a) Primary and Secondary - The owner will pay to the Company, prior to construction, a non-refundable contribution in aid of construction arrived at by multiplying the total length of trench feet required for distribution facilities by $***17.84*** plus $***18.47*** per kVA (nameplate) of transformer capacity to be installed.

(b) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

E Distribution for Commercial and Industrial Subdivisions

The Company will install underground facilities to serve commercial and industrial customers and other installations within designated underground districts in cooperation with the developer or owner, evidenced by a separate signed agreement, subject to the following specific conditions:

(1) General

(a) Where overhead lines are allowed by MPSC Rules for a specific installation and are objected to by a person or municipality, the Company, where feasible, will honor a request or directive that such lines be constructed underground. The objecting party shall be responsible for the payment of the additional cost of the underground facilities.

(b) When required, the developer or owner must provide suitable space and the necessary foundations and/or vaults for equipment and provide trenching, back-filling, conduits and manholes acceptable to the Company for installation of cables on his property.

(Continued on Sheet No. C-38.00)

(Continued from Sheet No. C-37.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.3 Underground Distribution Systems (Contd.)

(c) Distribution facilities in the vicinity of new industrial loads and built solely to serve such loads will be placed underground at the option of the applicant. This includes service to all buildings used primarily for the assembly, processing or manufacturing of goods.

(2) Charges

(a) Distribution System - For standard installation of distribution facilities, the applicant(s) shall make a non-refundable contribution in aid of construction in the amount equal to the total length in feet multiplied by $***17.84***.

(b) Transformers - Transformers will be charged on an installed basis of $***18.47*** per kVA.

(c) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

(3) Measurement

(a) <u>Trench length</u> shall be determined by measuring along the centerline of the trench.

Primary and Secondary Extensions shall be measured along the route of the primary and secondary cable from the transition pole to each transformer or other termination. No additional charge will be made for secondary or service cable laid in the same trench with primary cable.

C6.4 Underground Service Connections

The Company will install, own, operate and maintain underground service connections in cooperation with the developer or owner, evidenced by a separate signed agreement, subject to the following charges:

A Residential Subdivisions

The applicant shall make a non-refundable contribution in aid of construction for a standard 3/0 aluminum service in the amount of $***730*** for trench lengths up to 200 feet. For any additional trench length in excess of 200 feet the non-refundable contribution will be increased by $***9.48*** per foot for each additional foot added. When required, larger services will be provided, and the additional cost will be included in the non-refundable contribution in aid of construction. The trench length is measured from the Company's electrical connection, to the customer's meter.

(Continued on Sheet No. C-39.00)

(Continued from Sheet No. C-38.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.4 Underground Service Connections (Contd.)

B Residential Outside Subdivisions and Mobile Home Parks

The applicant shall make a non-refundable contribution in aid of construction for a standard 3/0 aluminum service in the amount equal to the product of the trench length in feet multiplied by $***9.48***. When required, larger services will be provided, and the additional cost will be included in the non-refundable contribution in aid of construction. All new, relocated or upgraded residential service connections will be installed as underground residential service laterals at the customer's expense as set forth in Section C6.4.

C Apartment House Complexes and Condominiums

The applicant shall make a non-refundable contribution in aid of construction in the amount equal to the product of the trench length in feet multiplied by $***17.84***. See C1.1 for service charge differences in secondary network areas.

No charge will be made for service laterals laid in the same trench with primary or secondary cables. Residential units shall be metered separately in accordance with Standard Contract Rider No. 4.

When any component of a secondary service involves a residential load, then the main building service utilization voltage shall be the residential voltage (i.e. 240/120 volts or 208Y/120 volts).

(1) Outdoor Pad-Mounted Installation – External Residential Meter Stacks:

(a) The Company will furnish, install, own and maintain the pre-meter portion of the individual service lateral between the distribution facilities and self-contained meter locations.

(b) Where service laterals are installed by the Company as in (a) above, the customer will furnish and install the service lateral in a manner suitable to the Company. The Company will make connection of the customer furnished lateral to its distribution system.

(2) Outdoor Pad-Mounted Installation – Mixed Use Secondary Served Buildings:

(a) When a commercial or industrial building is divided in such a manner as to require several self-contained meter locations (as described above), the owner shall be required to make provisions for a common pre-meter feed either by grouping meters in a manner and location acceptable to the Company, or by installing a Company approved secondary connection cabinet at a Company approved location. The owner shall install one (1) 4" conduit for every 400 amps or part thereof of capacity, based on the rating of the secondary connection cabinet, plus one (1) additional 4" conduit

(Continued on Sheet No. C-39.01)

(Continued from Sheet No. C-39.01)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.4 Underground Service Connections (Contd.)

(c) the tenant meter location. The meters must be grouped and installed in a manner acceptable to the Company. Residential meters must be installed in the same room as the dry-type transformers feeding them. The load at each transformer location must be sufficient to justify the use of one standard Company transformer or multiples thereof. Standard Company transformer sizes and secondary voltages for this application are: 167 kVA single phase 120/240 V and 300 kVA three-pjhase 208Y/120 V. Fuse cabinets and associated equipment will be furnished, owned and maintained by the Company at each transformer location. The fuse cabinents and associated equipment will be paid for and installed by the customer. The transformer locations must be suitable for the installation of dry type transformers and must be accessible for operation and maintenance. The installations must be approved by the Company and must meet code requirements. Suitable access and means shall be provided for transformer, fuse cabinet and associated equipment replacement. The customer shall be responsible for all damages and personal liability arising out of or in connection with the installation of the Company's transformers, fuse cabinets and associated equipment and shall also take reasonable steps to prevent damage to the transformers, fuse cabinets and associated equipment when they are installed on his property.

The owner will pay the following charges to the Company:

(a) $***17.84*** per trench foot of cable on private property between the primary switching equipment and the property lines nearest the point of connection to the Company distribution system-plus any other Company charges for unusual conditions.

(b) The installed cost of the primary switchgear.

(c) $15 per kVA for all dry type transformers.

(d) The delivered cost of the fuse cabinet and associated equipment.

(e) The developer or owner must provide suitable space and necessary foundations for pad-mounted transformer and the primary switchgear, etc., and he must provide for any trenching, conduit, or manholes acceptable to the Company.

(4) Measurement:

Service laterals shall be measured from the pole or underground secondary terminal to which the service lateral is connected along the route of the lateral trench or conduit to the point of connection to the customer's facilities. No charge will be made for service laterals laid in the same trench with primary or secondary cables.

(Continued on Sheet No. C-39.03)

M.P.S.C. No. 1 - Electric __________ Revised Sheet No. C-62.00
DTE Electric Company Cancels ____________ Sheet No. C-62.00
(Final Order Case No. U-21534)

(Continued from Sheet No. C-61.00)

C8 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE

C8.1 Power Supply Cost Recovery (PSCR) Clause

A This Power Supply Cost Recovery Clause permits the monthly adjustment of rates for power supply to allow recovery of the booked costs of fuel and purchased and net interchanged power transactions incurred under reasonable and prudent policies and practices in accordance with 1982 PA 304. All rates for electric service, unless otherwise provided in the applicable rate schedule, shall include a Power Supply Cost Recovery factor.

B The Power Supply Cost Recovery factor is that element of the rates to be charged for electric service to reflect power supply costs incurred by the company and made pursuant to the Power Supply Cost Recovery Clause.

C Effective __________***, 2025*** the Power Supply Cost Recovery Factor shall consist of an increase or decrease of ***0.010769*** mills per kWh for each full .01 mill increase or decrease in the projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a base of 31.26 mills per kWh. Average booked cost of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

The following factor(s) were applied to bills rendered during the billing months as indicated below for the calendar years 2023 and 2024.

	2023		**2024**	
Billing Month	**Maximum Authorized Factor ¢/kWh**	**Actual Factor Billed ¢/kWh**	**Maximum Authorized Factor ¢/kWh**	**Actual Factor Billed ¢/kWh**
January	1.917	0.665	1.127	1.127
February	1.917	0.665	1.127	1.127
March	1.917	1.750	1.127	1.127
April	1.917	1.750		
May	1.917	1.750		
June	1.917	1.917		
July	1.917	1.917		
August	1.917	1.917		
September	1.917	1.917		
October	1.917	1.917		
November	1.917	1.917		
December	1.917	1.127		

The Company will file a revised Sheet No. C-62.00 monthly, or as necessary, to reflect the factor to be billed the following month.

(Continued on Sheet No. C-63.00)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

M.P.S.C. No. 1 - Electric ______________ Revised Sheet No. C-65.00
DTE Electric Company Cancels ____________ Revised Sheet No. C-65.00
(Final Order Case No. U-21534)

(Continued from Sheet No. C-64.03)

C8 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE (Contd.)

C8.5 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE: Summary of surcharges and credits including PSCR, pursuant to sub-rules C8.1, C8.4 of this rule. (Cents per kilowatthour or percent of base bill unless otherwise noted).

	PSCR (¢/kWh)	Securitization Charge *River Rouge* (¢/kWh)	Securitization Charge TCSC (¢/kWh)	Total Power Supply Surcharges (excludes REPS) (¢/kWh)
Residential				
D1 Non Transmitting Meter	1.127	0.0240	0.2889	1.4399
D1.1 Int. Space Conditioning	1.127	0.0190	0.2285	1.3745
D1.2 Enhanced TOU	1.127	0.0156	0.1873	1.3299
D1.6 Special Low Income Pilot	1.127	0.0240	0.2889	1.4399
D1.7 Geothermal Time-of-Day	1.127	0.0142	0.1705	1.3117
D1.8 Dynamic Peak Pricing	1.127	0.0207	0.2493	1.3970
D1.9 Electric Vehicle	1.127	0.0182	0.2195	1.3647
D1.11 Standard TOU	1.127	0.0240	0.2889	1.4399
D1.13 Overnight Savers	1.127	0.0240	0.2889	1.4399
D2 Space Heating	1.127	0.0145	0.1751	1.3166
D5 Water Heating	1.127	0.0128	0.1540	1.2938
D9 Outdoor Lighting	1.127	0.0047	0.0563	1.1880
Commercial				
D1.1 Int. Space Conditioning	1.127	0.0165	0.1981	1.3416
D1.7 Geothermal Time-of-Day	1.127	0.0109	0.1316	1.2695
D1.8 Dynamic Peak Pricing	1.127	0.0171	0.2062	1.3503
D1.9 Electric Vehicle	1.127	0.0242	0.2917	1.4429
D3 General Service	1.127	0.0191	0.2303	1.3764
D3.1 Unmetered	1.127	0.0159	0.1918	1.3347
D3.2 Educ. Inst.	1.127	0.0166	0.1995	1.3431
D3.3 Interruptible	1.127	0.0160	0.1924	1.3354
D3.5 Charging	1.127	0.0191	0.2303	1.3764
D3.11 TOU General Service	***1.127***	***0.0191***	***0.2303***	***1.3764***
D4 Large General Service	1.127	0.0168	0.2026	1.3464
D5 Water Heating	1.127	0.0113	0.1356	1.2739
D9 Outdoor Lighting	1.127	0.0047	0.0563	1.1880
R3 Standby (Secondary)	1.127	0.0131	0.1579	1.2980
R7 Greenhouse Lighting	1.127	0.0109	0.1316	1.2695
R8 Space Conditioning	1.127	0.0167	0.2014	1.3451
Industrial				
D6.2 Educ. Inst.	1.127	0.0173	0.2081	1.3524
D8 Interruptible Primary	1.127	0.0099	0.1189	1.2558
D10 Schools	1.127	0.0169	0.2029	1.3468
D11 Primary Supply	1.127	0.0136	0.1635	1.3041
D12 Large Low Peak	1.127	0.0136	0.1635	1.3041
D13 XL	NA	0.0022	0.0262	0.0284
D14 TOU Primary Supply	***1.127***	***0.0136***	***0.1635***	***1.3041***
R1.1 Metal Melting	1.127	0.0102	0.1083	1.2455
R1.2 Electric Process Heating	1.127	0.0087	0.1061	1.2418
R3 Standby (Primary)	1.127	0.0131	0.1579	1.2980
R10 Interruptible Supply	NA	0.0022	0.0262	0.0284
Governmental				
E1 Streetlighting	1.127	0.0046	0.0555	1.1871
E1.1 Energy Only	1.127	0.0132	0.1591	1.2993
E2 Traffic Lights	1.127	0.0125	0.1499	1.2894

(Continued on Sheet No. C-66.00)

(Continued from Sheet No. C-65.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE

C9.1 Nuclear Surcharge (NS)

On January 1987 MPSC Order authorized the establishment of an external trust fund to finance the decommissioning of Fermi 2 Power Plant when its operating license expires. The Order approves a decommissioning surcharge on customer bills under which the funds are collected. Pursuant to Commission Order U-10102 dated January 21, 1994, a revised surcharge became effective with service rendered on and after January 22, 1994. In the same order, the Commission authorized the establishment of an external fund to finance the disposal of low-level radioactive waste during the operating life of Fermi 2 Power Plant. Pursuant to an order in Case No. U-14399, costs associated with site security and radiation protection services were removed from base rates and transferred to the Nuclear Surcharge. Pursuant to Commission Order U-16472 dated October 20, 2011, a revised surcharge became effective with service rendered on and after October 29, 2011 Pursuant to Commission Order in Case No. U-17767 a revised surcharge became effective with service rendered on and after December 17, 2015**.** Pursuant to Commission Order in Case No. U-18255 a revised surcharge became effective with service rendered on and after April 18, 2018**.** Pursuant to Commission Order in Case No. U-20162 a revised surcharge became effective with service rendered on and after May 9, 2019**.** Pursuant to Commission Order in Case No. U-20561 a revised surcharge became effective with service rendered on and after May 15, 2020. Pursuant to Commission Order in Case No. U-20836 a revised surcharge became effective with service rendered on and after November 25 ,2022. Pursuant to Commission Order in Case No. U-21297 a revised surcharge became effective with service rendered on and after December 15 ,2023. ***Pursuant to Commission Order in Case No. U-21534 a revised surcharge became effective with service rendered on and after _________, 2025.***

C9.2 HOLD FOR FUTURE USE

C9.3 HOLD FOR FUTURE USE

C9.4 HOLD FOR FUTURE USE

(Continued on Sheet No. C-67.00)

(Continued from Sheet No. C-69.01)

C9.7.11 INVESTMENT RECOVERY MECHANISM

On December 15, 2023, the Michigan Public Service Commission approved the Investment Recovery Mechanism (IRM) in Case No. U-21297. The IRM recovers costs related to certain distribution system investments. A schedule of IRM surcharges approved by the Commission is reflected below. The IRM surcharge is applied on the same basis as the underlying rate schedule. The surcharge schedule ***is*** updated consistent with the ___________, ***2025*** Commission Order ***in Case No. U-21534***.

	13mos Ending December 31, 2024	**Year Ending December 31, 2025**	**Year Ending December 31, 2026**	
All residential, except as noted below (¢/kWh)	0.0139	0.0941	***0.2034***	
Commercial				
All commercial, except as noted below (¢/Kwh)	0.0088	0.0595	***0.1297***	
Rate Schedule D4 ($/kW)	0.0362	0.2454	***0.5597***	
Industrial				
Primary, except as noted below ($/kW)	0.0107	0.0727	***0.1497***	
Subtransmission, except as noted below ($/kW)	0.0046	0.0312	***0.0561***	
Transmission, except as noted below ($/kW)	0.0000	0.0000	***0.0000***	
Rate Schedule D10 (¢/Kwh)	0.0034	0.0233	***0.0443***	
Rider 1.1 / 1.2 (Distribution Voltage) (¢/Kwh)	0.0082	0.0555	***0.1297***	
Rider 1.1 / 1.2 (Primary Voltage) (¢/Kwh)	0.0034	0.0229	***0.0445***	
Rider 1.1 / 1.2 (Subtransmission Voltage) (¢/Kwh)	0.0015	0.0104	***0.0157***	
Rider 1.1 / 1.2 (Transmission Voltage) (¢/Kwh)	0.0000	0.0000	***0.000000***	
D13 (Primary Voltage) (¢/Kwh)	0.0020	0.0133	***0.0273***	
D13 (Subtransmission Voltage) (¢/Kwh)	0.0008	0.0057	***0.0102***	
D13 (Transmission Voltage (¢/Kwh)	0.0000	0.0000	***0.000000***	
Other				

D9 OPL (Residential) (¢/Kwh)	0.0778	0.5352	***1.2061***	
D9 OPL (Commercial) (¢/Kwh)	0.0434	0.2988	***0.6185***	
E1 St Light (¢/Kwh)	0.0819	0.5140	***1.1070***	
E2 Signals (¢/Kwh)	0.0040	0.0275	***0.0601***	

C9.7.11 HOLD FOR FUTURE USE

C9.7.12 HOLD FOR FUTURE USE

C9.7.13 HOLD FOR FUTURE USE

(Continued on Sheet No. C-69.03)

(Continued from Sheet No. C-69.02)

Continued on Sheet No. C-70.00)

(Continued from Sheet No. C-69.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits: Summary of surcharges and credits, pursuant to sub-rules C9.1, C9.2, C9.6, C9.7.9, and C.9.7.14. Cents per kilowatthour or percent of base bill, unless otherwise noted.

	NS ¢/kWh	EWRS ¢/kWh	Base Securitization ¢/kWh	IRM ¢/kWh	Total Delivery Surcharges ¢/kWh	LIEAF Factor $/Billing Meter
Residential						
D1 Non Transmitting Meter	***0.0911***	0.2552	0.1630	0.0139	***0.5232***	$0.88
D1.1 Int. Space Conditioning	***0.0911***	0.2552	0.1514	0.0139	***0.5116***	N/A
D1.2 Enhanced TOU	***0.0911***	0.2552	0.1493	0.0139	***0.5095***	$0.88
D1.6 Special Low Income Pilot	***0.0911***	0.2552	0.1630	0.0139	***0.5232***	$0.88
D1.7 Geothermal Time-of-Day	***0.0911***	0.2552	0.1411	0.0139	***0.5013***	N/A
D1.8 Dynamic Peak Pricing	***0.0911***	0.2552	0.1628	0.0139	***0.5230***	$0.88
D1.9 Electric Vehicle	***0.0911***	0.2552	0.1595	0.0139	***0.5197***	N/A
D1.11 Standard TOU	***0.0911***	0.2552	0.1630	0.0139	***0.5232***	$0.88
D1.13 Overnight Savers	***0.0911***	0.2552	0.1630	0.0139	***0.5232***	$0.88
D2 Space Heating	***0.0911***	0.2552	0.1583	0.0139	***0.5185***	$0.88
D5 Wtr Htg	***0.0911***	0.2552	0.1561	0.0139	***0.5163***	N/A
D9 Outdoor Lighting	***0.0911***	0.2552	0.1371	0.0778	***0.5612***	N/A
Commercial						
D1.1 Int. Space Conditioning	***0.0911***	See C9.6	0.1086	0.0088		$0.88
D1.7 Geothermal Time–of- day	***0.0911***	See C9.6	0.0734	0.0088		$0.88
D1.8 Dynamic Peak Pricing	***0.0911***	See C9.6	0.0908	0.0088		$0.88
D1.9 Electric Vehicle	***0.0911***	See C9.6	0.1920	0.0088		$0.88
D3 General Service	***0.0911***	See C9.6	0.0999	0.0088		$0.88
D3.1 Unmetered	***0.0911***	See C9.6	0.0939	0.0088		N/A
D3.2 Educ. Inst.	***0.0911***	See C9.6	0.0877	0.0088		$0.88
D3.3 Interruptible	***0.0911***	See C9.6	0.0899	0.0088		$0.88
D3.5 Charging	***0.0911***	See C9.6	0.0999	0.0088		$0.88
D3.11 TOU General Service	***0.0911***	***See C9.6***	***0.0999***	***0.0088***		***$0.88***
D4 Large General Service	***0.0911***	See C9.6	0.1044	See C9.7.11		$0.88
D5 Wtr Htg	***0.0911***	See C9.6	0.0988	0.0088		$0.88
D9 Outdoor Lighting	***0.0911***	See C9.6	0.1371	0.0434		N/A
R3 Standby Secondary	***0.0911***	See C9.6	0.0140	0.0088		$0.88
R7 Greenhouse Lighting	***0.0911***	See C9.6	0.0896	0.0088		$0.88
R8 Space Conditioning	***0.0911***	See C9.6	0.0977	0.0088		$0.88
Industrial						
D6.2 Educ. Inst.	***0.0911***	See C9.6	0.0167	See C9.7.11		$0.88
D8 Interruptible Primary	***0.0911***	See C9.6	0.0096	See C9.7.11		$0.88
D10 Schools	***0.0911***	See C9.6	0.0230	See C9.7.11		$0.88
D11 Primary Supply	***0.0911***	See C9.6	0.0082	See C9.7.11		$0.88
D12 Large Low Peak	***0.0911***	See C9.6	0.0082	See C9.7.11		$0.88
D13 XL	N/A	See C9.6	0.0033	See C9.7.11		$0.88
D14 TOU Primary Supply	***0.0911***	***See C9.6***	***0.0082***	***See C9.7.11***		***$0.88***
R1.1 Metal Melting	***0.0911***	See C9.6	0.0099	See C9.7.11		$0.88
R1.2 Electric Process Heating	***0.0911***	See C9.6	0.0157	See C9.7.11		$0.88
R3 Standby Primary	***0.0911***	See C9.6	0.0140	See C9.7.11		$0.88
R10 Interruptible Supply	***0.0911***	See C9.6	0.0033	See C9.7.11		$0.88

(Continued on Sheet No. C-71.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

_______________ Revised Sheet No. C-71.00
Cancels _______________ Sheet No. C-71.00

(Continued from Sheet No. C-70.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits (Contd.):

	NS ¢/kWh	EWRS ¢/kWh	TRM ¢/kWh	Base Securitization ¢/kWh	*IRM ¢/kWh*	Total Delivery Surcharges ¢/kWh	LIEAF Factor $/Billing Meter
Governmental							
E1 Streetlighting Option I	***0.0911***	See C9.6	0.1467	0.1882	0.0819		N/A
E1 Streetlighting Option II & III	***0.0911***	See C9.6	0.1467	0.1882	0.0819		N/A
E1.1 Energy Only	***0.0911***	See C9.6	0.1467	0.0922	0.0088		$0.88
E2 Traffic Lights	***0.0911***	See C9.6	0.1467	0.0407	0.0040		N/A
Electric Choice							
EC2 Residential	***0.0911***	See C9.6	0.1467	Note 1	0.0139		$0.88
EC2 Commercial	***0.0911***	See C9.6	0.1467	Note 1	See C9.7.11		$0.88
EC2 Primary	***0.0911***	See C9.6	0.1467	Note 1	See C9.7.11		$0.88

NOTE 1: Electric choice tariffs will be billed ***surcharges and credits applicable to delivery service*** for ***the*** corresponding full service tariff***, unless otherwise noted***.

(Continued on Sheet No. C-72.00)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after _________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ___________________, 2025
in Case No. U-21534

RATE SCHEDULE NO. D1 **RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER**

AVAILABILITY OF SERVICE: Available to customers desiring service for all residential purposes through one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter.

This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications. This rate is only available for residential customers with a non-transmitting meter.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges:	***3.110¢*** per kWh for the first 17 kWh per day
	4.484¢ per kWh for excess over 17 kWh per day
Non-Capacity Energy Charge*:*	***5.655¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE:

Capacity Energy Charges:	***3.110¢*** per kWh for the first 17 kWh per day
	4.484¢ per kWh for excess over 17 kWh

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

(Continued on Sheet No. D-2.00)

(Continued from Sheet No. D-1.00)

RATE SCHEDULE NO. D1 (Contd.) **RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER**

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

(Continued on Sheet No. D-2.01)

(Continued from Sheet No. D-2.00)

RATE SCHEDULE NO. D1 (Contd.) **RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER**

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) ***or the Low Income Assistance Credit (LIA***).

RATE SCHEDULE NO. D1.1 **INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to Residential and Commercial customers desiring separately metered interruptible service for central air conditioning and/or central heat pump use. Customers who have more than one heat pump and/or air-conditioning unit which serves their business or home, will not be permitted to have only a portion of their load on the rate, all units will be interrupted upon the signal from the Company. Installations must conform with the Company's specifications. This rate is not available to commercial customers being billed on a demand rate. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours.

HOURS OF INTERRUPTION: Interruptions may be called for, but not limited to, system testing and evaluation, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit interruptions to intervals of no longer than 30 minutes in any hour and no longer than 8 hours in any 24-hour period.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH: For separately metered space-conditioning service.

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through October):	***2.969¢*** per kWh for all kWh
Capacity Energy Charge (November through May):	***0.736¢*** per kWh for all kWh
Non-Capacity Energy Charge:	***4.415¢*** per kWh for all kWh

Residential Delivery Charges:

Service Charge (June through October):	$1.95 per month
Distribution Charge (Year-round):	***8.907¢*** per kWh for all kWh

Commercial Power Supply Charges:

Capacity Energy Charge (June through October):	***2.878¢*** per kWh for all kWh
Capacity Energy Charge (November through May):	***1.289¢*** per kWh for all kWh
Non-Capacity Energy Charge:	***4.634¢*** per kWh for all kWh

Commercial Delivery Charges:

Service Charge (June through October):	$1.95 per month
Distribution Charge (Year-round):	***5.858¢*** per kWh for all kWh

(Continued on Sheet No. D-5.00)

(Continued from Sheet No. D-4.00)

RATE SCHEDULE NO. D1.1 (Contd.) **INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE**

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE***:***

Capacity Energy Charge (June through October):	***2.969¢*** per kWh for all kWh
Capacity Energy Charge (November through May***):***	***0.736¢*** per kWh for all kWh

Residential Delivery Charges:

Capacity Service Charge June through October):	$1.95 per month
Capacity Distribution Charge (Year-round):	***8.907¢*** per kWh for all kWh

Commerical Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through October):	***2.878¢*** per kWh for all kWh
Capacity Energy Charge (November through May):	***1.289¢*** per kWh for all kWh

Commercial Delivery Charges:

Service Charge June through October):	$1.95 per month
Distribution Charge (Year-round):	***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

RATE SCHEDULE NO. D1.2 **RESIDENTIAL SERVICE RATE – ENHANCED TOU**

AVAILABILITY OF SERVICE: Available on an optional basis to customers who desire time of day service for their residential dwelling. Customers who select this rate must qualify for the Residential Service Rate Standard TOU D1.11.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge (June through October):
4.746¢ per kWh for all On-peak kWh
1.598¢ per kWh for all Off-peak kWh

Capacity Energy Charge (November through May):
4.009¢ per kWh for all On-peak kWh
1.535¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through October)
11.144¢ per kWh for all On-peak kWh
3.752¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (November through May)
9.413¢ per kWh for all On-peak kWh
3.605¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: $8.50 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:
Capacity Energy Charge (June through October):
4.746¢ per kWh for all On-peak kWh
1.598¢ per kWh for all Off-peak kWh

(Continued on Sheet No. D-6.01)

(Continued from Sheet No. D-6.00)

RATE SCHEDULE NO. D1.2 (Contd.) **RESIDENTIAL SERVICE RATE – ENHANCED TOU**

Retail Access Service Customers (Contd.):

Capacity Energy Charge (November through May):
4.009¢ per kWh for all On-peak kWh
1.535¢ per kWh for all Off-peak kWh

On-Peak Hours: all kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: all other kWh used.

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Commencing upon installation of the Time-of-Day meter, service will be provided for twelve continuous months thereafter, with termination upon mutual consent of the Company and the customer.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be

taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

(Continued on Sheet No. D-7.00)

(Continued from Sheet No. D-6.01)

RATE SCHEDULE NO. D1.2 (Contd.) **RESIDENTIAL SERVICE RATE– ENHANCED TOU**

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) ***or the Low Income Assistance Credit (LIA***).

RATE SCHEDULE NO. D1.6 RESIDENTIAL SERVICE RATE - SPECIAL LOW INCOME PILOT

AVAILABILITY OF SERVICE: Customers who select this pilot rate must qualify for the Residential Service rate D1. To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to an annual average of 32,000 customers.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: ***3.11¢*** per kWh for the first 17 kWh per day
4.484¢ per kWh for excess over 17 kWh per day

Non-Capacity Energy Charge***:*** ***5.655¢*** per kWh for all kWh per day

Delivery Charges:

Service Charge: $8.50 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh
Special Low Income Discount: ($***50.00***) per month

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charges***:*** ***3.11¢*** per kWh for first 17 kWh per day
4.484¢ per kWh for excess over 17 kWh per day

(Continued on Sheet No. D-12.02)

(Continued from Sheet No. D-12.01)

RATE SCHEDULE NO. D1.6 (Contd.)RESIDENTIAL SERVICE RATE - SPECIAL LOW INCOME PILOT

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh
Special Low Income Discount:	($***50.00***) per month

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

CONTRACT TERM: Open order, terminable on three days' notice by either party. If a customer fails to make the required payment on time for three consecutive billing periods that customer shall automatically be removed from this rate. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

RATE SCHEDULE NO. D1.7 **GEOTHERMAL TIME-OF-DAY RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to residential customers desiring separately metered service for approved geothermal space conditioning and/or water heating. To qualify for the rate the water heater must be for sanitary purposes with the tank size, design and method of installation approved by the company. The space conditioning equipment must be permanently installed.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Same as D1 and D3 Rates

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days notice after the initial 12 months by either party. Where special services are required, the term will be specified on the applicable contract rider.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

RATE PER DAY:

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through September):
5.395¢ per kWh for all On-peak kWh
1.787¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
2.331¢ per kWh for all On-peak kWh
1.832¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September)
8.441¢ per kWh for all On-peak kWh
2.796¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (October through May)
3.647¢ per kWh for all On-peak kWh
2.866¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Residential Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***8.907¢*** per kWh for all kWh

(Continued on Sheet No. D-13.01)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

(Continued from Sheet No. D-13.00)

RATE SCHEDULE NO. D1.7 (Contd.) **GEOTHERMAL TIME-OF-DAY RATE**

Commercial Power Supply Charges:

Capacity Energy Charge (June through September):
1.688¢ per kWh for all On-peak kWh
1.542¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
1.578¢ per kWh for all On-peak kWh
1.578¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September)
3.307¢ per kWh for all On-peak kWh
3.020¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (October through May)
3.092¢ per kWh for all On-peak kWh
3.092¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Commercial Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September):
5.395¢ per kWh for all On-peak kWh
1.787¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
2.331¢ per kWh for all On-peak kWh
1.832¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

(Continued on Sheet No. D-13.02)

(Continued from Sheet No. D-13.01)

RATE SCHEDULE NO. D1.7 (Contd.) **GEOTHERMAL TIME-OF-DAY RATE**

Residential Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***8.907¢*** per kWh for all kWh

Commerical Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September***):***

1.688¢ per kWh for all On-peak kWh
1.542¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

1.578¢ per kWh for all On-peak kWh
1.578¢ per kWh for all Off-peak kWh

Commercial Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C5.8.

RATE SCHEDULE NO. D1.8 **RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING**
GENERAL SERVICE RATE – DYNAMIC PEAK PRICING

AVAILABILITY OF SERVICE: Available on an optional basis to full-service residential and secondary commercial and industrial customers seeking to manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. Service under this rate is limited to a residential customers and secondary commercial and industrial customers who have Advanced Metering Infrastructure installed. Service under this rate may not be combined with any other tariff, rider, or separately metered service, other than Rider 18 (if available).

The rate features three price tiers for On-Peak, Mid-Peak, and Off-Peak, as well as Critical Peak prices for days where Critical Hours are announced.

Definitions:

On-Peak Hours:	All kWh used between 3P.M. and 7P.M. Monday through Friday, excluding holidays
Mid-Peak Hours:	All kWh used between 7A.M. and 3P.M., and between 7P.M. and 11P.M., Monday through Friday excluding holidays
Off-Peak Hours:	All kWh used between 11 P.M and 7 A.M. Monday through Friday, and all weekend and holiday hours.
Critical-Peak Hours:	All kWh used during critical hours, which, when announced, will replace the full on-peak time period from 3 P.M. to 7 P.M.

HOURS OF INTERRUPTION: Critical Peak hours may be called for, but not limited to, system testing and evaluation, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit Critical Peak pricing to no more than 56 hours per year.

NOTICE OF INTERRUPTION: Customers will be notified by up to 24 hours before, but no less than 6 hours before critical hours are expected to occur. Notification will be made by one or more of the following methods: automated telephone message, text message, e-mail, or presentment on an in-premise display unit furnished by the Company. Receipt of such notice is the responsibility of the participating customer.

Customers who qualify and sign up for this rate agree to participate in evaluation surveys and will remain anonymous on all such surveys.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt, single-phase three-wire; or 208Y/120 volts, three-phase four wire service may be taken.

(Continued on Sheet No. D-14.01)

(Continued from Sheet No. D-14.00)

RATE SCHEDULE NO. D1.8 (Contd.)**RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING RATE**
GENERAL SERVICE RATE – DYNAMIC PEAK PRICING

CHARGES:

Full Service Residential Customers:

Power Supply Charges:

Capacity Energy Charges:	***6.612¢*** per kWh for all On-Peak kWh
	3.452¢ per kWh for all Mid-Peak kWh
	1.781¢ per kWh for all Off-Peak kWh
	$***0.8439*** per kWh for all kWh during Critical Peak Hours
Non-Capacity Energy Charge:	***10.610¢*** per kWh for all On-Peak kWh
	5.444¢ per kWh for all Mid-Peak kWh
	2.809¢ per kWh for all Off-Peak kWh
	$***0.10610*** per kWh for all kWh during Critical Peak Hours

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

Full Service Secondary Commercial and Industrial Customers:

Power Supply Charges:

Capacity Energy Charges:	***5.595¢*** per kWh for all On-Peak kWh
	3.037¢ per kWh for all Mid-Peak kWh
	1.546¢ per kWh for all Off-Peak kWh
	$***0.83785*** per kWh for all kWh during Critical Peak Hours
Non-Capacity Energy Charge:	***11.215¢*** per kWh for all On-Peak kWh
	5.998¢ per kWh for all Mid-Peak kWh
	3.053¢ per kWh for all Off-Peak kWh
	$***0.11215*** per kWh for all kWh during Critical Peak Hours

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

SCHEDULE OF HOLIDAYS: See Section C11

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days' notice after the initial 12 months by either party.

LATE PAYMENT CHARGE: See Section C4.8.

(Continued on Sheet No. D-14.02)

(Continued from Sheet No. D-14.01)

RATE SCHEDULE NO. D1.8 (Contd.)**RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING RATE GENERAL SERVICE RATE – DYNAMIC PEAK PRICING**

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Low Income Assistance Credit (LIA).

RATE SCHEDULE NO. D1.9 **ELECTRIC VEHICLE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to residential and commercial customers desiring separately metered service for the sole purpose of charging licensed electric vehicles. Installations must conform to the Company's specifications. Service under this tariff is limited to 5,000 customers. Service on this rate is limited to electric vehicles that are SAE J1772 compliant, and all vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for the program.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three wire. In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified on the applicable contract rider.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

OPTION 1: TIME OF DAY PRICING

Full Service Customers:

Power Supply Charges:
Capacity Energy Charge:
6.775¢ per kWh for all On-peak kWh
1.695¢ per kWh for all Off-peak kWh
Non-Capacity Energy Charge:
10.608¢ per kWh for all On-peak kWh
2.651¢ per kWh for all Off-peak kWh
On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:
Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:
Capacity Energy Charge:
6.775¢ per kWh for all On-peak kWh
1.695¢ per kWh for all Off-peak kWh

(Continued on Sheet No. D-14.04)

(Continued from Sheet No. D-14.03)

RATE SCHEDULE NO. D1.9 (Contd.) **ELECTRIC VEHICLE RATE**

Retail Access Service Cutomer (Contd.):

On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See C8.5.

OPTION 2: MONTHLY FLAT FEE (Residential only)*:*
Closed to new customers as of May 31, 2019. Existing customers will be moved to a new rate by December 31, 2019.

SPECIAL TERMS AND CONDITIONS:

Service under this rate must be supplied through a separately metered circuit and approved electric vehicle charging equipment. Installations must conform with the Company's specifications.

The Company is exploring additional possible metering options to be offered at the Company's discretion. This includes but is not limited to, collecting data directly from charging stations and/or utilizing technology beyond the general service meter to measure EV usage.

RATE SCHEDULE NO. D1.11 **RESIDENTIAL SERVICE RATE – STANDARD TOU**

AVAILABILITY OF SERVICE: This rate will be available for service no later than May 31, 2023. Available to customers desiring service for all residential purposes though one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter.

This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications.

HOURS OF SERVICE*:* 24 hours.

CURRENT, PHASE AND VOLTAGE*:* Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:
Capacity Energy Charge (June through September):
5.649 cents per kWh for all On-peak kWh
3.403 cents per kWh for all Off-peak kWh
Capacity Energy Charge (October through May):
3.984 cents per kWh for all On-peak kWh
3.403 cents per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September):
8.838 cents per kWh for all On-peak kWh
5.325 cents per kWh for all Off-peak kWh

Non-Capacity Energy Charge (October through May):
6.233 cents per kWh for all On-peak kWh
5.325 cents per kWh for all Off-peak kWh

On-Peak Hours:	All kWh used between 3:00PM and 7:00PM Monday through Friday.
Off-Peak Hours:	All other kWh used.

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

(Continued on Sheet No. D-14.06)

(Continued from Sheet No. D-14.05)

RATE SCHEDULE NO. D1.11 (Contd.) **RESIDENTIAL SERVICE RATE – STANDARD TOU**

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE:

Capacity Energy Charge (June through September):
5.649 cents per kWh for all On-peak kWh
3.403 cents per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
3.984 cents per kWh for all On-peak kWh
3.403 cents per kWh for all Off-peak kWh

Delivery Charges:

Service Charge:	$8.50 per month
Distribution Charge:	***8.907¢*** per kWh for all kWh

Surcharges and Credits*:* As approved by the Commission. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE*:* Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION*:* Rate D1.1 is available on an optional basis.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

(Continued on Sheet No. D-14.07)

(Continued from Sheet No. D-14.06)

RATE SCHEDULE NO. D1.11 (Contd.) **RESIDENTIAL SERVICE RATE – STANDARD TOU**

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Low Income Assistance Credit (LIA).

RATE SCHEDULE NO. D1.13 **RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS**

AVAILABILITY OF SERVICE: Available to customers desiring service for all residential purposes though one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter. This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications. Service on this rate is limited to 10,000 customers. This rate will be effective no later than November 30, 2024.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

June – September – all values in cents per kWh

	Power supply capacity Charge	**Power Supply Non Capacity Charge**	**Distribution Charge**
On peak	***6.285***	***9.833***	***17.941***
Off peak	***4.229***	***6.617***	***13.456***
Super Off-peak	***2.671***	***4.179***	***4.485***

October – May – all values in cents per kWh

	Power supply capacity Charge	**Power Supply Non Capacity Charge**	**Distribution Charge**
On peak	***3.585***	***5.609***	***8.970***
Off peak	***3.218***	***5.034***	***6.728***
Super Off-peak	***2.671***	***4.179***	***4.485***

On-Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.
Super Off-peak: All kWh used between 1:00AM and 7:00AM
Off-Peak Hours: All other kWh used.

Delivery Charges:
Service Charge: $8.50 per month
Distribution Charge: see table above

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

(Continued on Sheet No. D-14.09)

(Continued from Sheet No. D-14.08)

RATE SCHEDULE NO. D1.13 (Contd.) **RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS**

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE

June – September – all values in cents per kWh

	Power supply capacity Charge	**Distribution Charge**
On peak	***6.285***	***17.941***
Off peak	***4.229***	***13.456***
Super Off-peak	***2.671***	***4.485***

October – May – all values in cents per kWh

	Power supply capacity Charge	**Distribution Charge**
On peak	***3.585***	***8.970***
Off peak	***3.218***	***6.728***
Super Off-peak	***2.671***	***4.485***

On-Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.
Super Off-peak: All kWh used between 1:00AM and 7:00AM
Off-Peak Hours: All other kWh used.

Delivery Charges:
Service Charge: $8.50 per month
Distribution Charge: see table above

Surcharges and Credits: As approved by the Commission. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days' notice after the initial 12 months by either party, at which time the customer may take service on any other rate for which they are eligible.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

(Continued on Sheet No. 14.10)

(Continued from Sheet No. D-14.09)

RATE SCHEDULE NO. D1.13 (Contd.) **RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS**

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Low Income Assistance Credit (LIA).

RATE SCHEDULE NO. D2 **RESIDENTIAL SERVICE RATE - SPACE HEATING**

AVAILABILITY OF SERVICE: Available on an optional basis to customers desiring service for all residential purposes to a single or double occupancy dwelling unit including farm dwellings. All of the space heating must be total electric installed on a permanent basis and served through one meter. This rate also available to customers with add-on heat pumps and fossil fuel furnaces served on this rate prior to July 16, 1985. The design and method of installation and control of equipment as adopted to this service are subject to approval by the Company. This rate is also available to customers with electric heat assisted with a renewable heat source.

This rate is available only to dwellings being served on this rate prior to December 17, 2015.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally. In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: (June through October):	***2.988¢*** per kWh for the first 17 kWh per day
	4.272¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May):	***1.761¢*** per kWh for the first 20 kWh per day
	0.688¢ per kWh for over 20 kWh per day
Non-Capacity energy Charge:	***5.164¢*** per kWh for all kWh

Delivery Charges:

Service Charge	$8.50 per month
Distribution Charge: (June through October):	***8.907¢*** per kWh for all kWh
Distribution Charge: (November through May):	***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge

Retail Access Service customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE***:***

Capacity Energy Charges: (June through October):	***2.988¢*** per kWh for the first 17 kWh per day
	4.272¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May):	***1.761¢*** per kWh for the first 20 kWh per day
	0.688¢ per kWh for over 20 kWh per day

(Continued on Sheet No. D-16.00)

(Continued from Sheet No. D-15.00)

RATE SCHEDULE NO. D2 (Contd.) **RESIDENTIAL SERVICE RATE - SPACE HEATING**

Delivery Charges:

Service Charge	$8.50 per month
Distribution Charge: (June through October):	***8.907¢*** per kWh for all kWh
Distribution Charge: (November through May):	***8.907¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. ***If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.***

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(8.50) per customer per month

LOW INCOME ASSISTANCE CREDIT PILOT: This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision. In addition to the income verification methods listed above, a customer may qualify for the Low-

Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as LOW INCOME ASSISTANCE CREDIT PILOT (contd.): sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months. If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows:

Income Assistance Credit: $(50.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility Charges.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a Principal Residence Customer, who is 65 years of age or older and head of household, a credit shall be applied during all billing months. The monthly credit for the Residential Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is $(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Low Income Assistance Credit (LIA).

RATE SCHEDULE NO. D3 **GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose. This rate is not available for service in conjunction with the Large General Service Rate except when used exclusively to serve electric vehicle service equipment. When exclusively serving electric vehicle service equipment, this rate may also be taken in conjunction with Rate Schedules D6.2, D8, D11, or D12. At the Company's option, service may be available to loads in excess of 1000 kW for situations where significant modifications to service facilities are not required to serve the excess load. The 1000 kW discretionary demand restriction does not apply to service provided to Electric Vehicle Fast-Charging Stations until June 1, 202***8*** for existing stations and for two years after beginning service for new stations. Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: ***2.763¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***5.413¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:
Capacity Energy Charg***e:*** ***2.763¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

(Continued on Sheet No. D-19.00)

RATE SCHEDULE NO. D3.1 **UNMETERED GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available at the option of the Company to customers for loads that can be readily calculated and are impractical to meter.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, or reimburse the Company therefore. Connections are to be brought to the Company's underground or overhead lines by the customer as directed by the Company, and the final connections to the Company's line are to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATE: Capacity charge of ***2.348¢*** and non-capacity charge of ***10.459¢*** both applied per month per kilowatthour of the total connected load in service for each customer. Loads operated cyclically will be prorated. This rate is based on 350 hours per month. Proration of cyclical loads will not apply when hours of operation are within 10% of base. Proration may either increase or decrease connected load.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: $3.00 per month.

CONTRACT TERM: Open order on a month-to-month basis.

RATE SCHEDULE NO. D3.2 **SECONDARY EDUCATIONAL INSTITUTION RATE**

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at secondary voltage. School shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational training, or occupational school. "College" or "University" shall mean buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: ***2.573¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***5.335¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:
Capacity Energy Charge*:* ***2.573¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the approved commission. See section C8.5.

LATE PAYMENT CHARGE: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

(Continued on Sheet No. D-20.02)

RATE SCHEDULE NO. D3.3 **INTERRUPTIBLE GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to no more than 300 customers desiring interruptible service in conjunction with service taken under the general service rate. Service to interruptible load may be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company. Service to interruptible load may not be transferred to firm service circuits to avoid interruption. At the Company's option, in lieu of the requirement for separately metered circuits and associated interruption equipment the customer may elect to contract for a minimum firm load demand to protect product or process loads in accordance with the product protection provision of this tariff. Under this option, interval demand metering will be installed in order to monitor compliance when called to interrupt load. This rate is not available for loads that are primarily off-peak, such as outdoor lighting. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours except as described below.

HOURS OF INTERRUPTION: All interruptible load served hereunder shall be subject to interruption by the Company and may include interruptions for, but not limited to, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3.

TESTING PROCEDURES: In accordance with participation in an interruptible tariff, the customer agrees to comply with Company requirements regarding testing procedures. Customer shall complete and sign an interruptible responsibility letter annually by April 1st. Failure to sign and submit the interruptible responsibility letter may result in removal from this interruptible tariff. The letter designates that the customer understands their responsibility to interrupt, has an interruption plan, and has the capability to interrupt the contracted load. In addition, the Company will conduct multiple simulations each year to verify the communication system is working properly.

NOTICE OF INTERRUPTION: The customer shall be provided, whenever possible***;*** 1) notice in advance (generally 1 hour) of probable interruption***;*** 2) the time in which customer must fully reduce its interruptible load, and***;*** 3) the estimated duration of the interruption. The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of Interruption shall be billed at the higher of (i) the rate of $50 per kW applied to the highest 60-minute integrated interruptible demand (kW) or (ii) the actual damages incurred by the Company, including any MISO penalties, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with an interruption order may be immediately reduced by the amount by which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

(Continued on Sheet No. D-22.00)

(Continued from Sheet No. D-21.00)

RATE SCHEDULE NO. D3.3 (Contd.) **INTERRUPTIBLE GENERAL SERVICE RATE**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: ***2.309¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***4.523¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE***:***
Capacity Energy Charge: ***2.309¢*** per kWh for all kWh

Delivery Charges:

Service Charge: $11.25 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

PRODUCT PROTECTION PROVISION*:* (Full Service Customers Only): A customer on rate D3.3 may elect to contract for a minimum load during the period of interruption to protect his product or process. This minimum load called "product protection load" shall not exceed 50% of the total contracted interruptible load and shall be charged rates equal to the General Service Rate (D3) power supply charge.

CONTRACT TERM: The contract term is one year, extending thereafter from month-to-month until terminated by mutual consent or on twelve months written notice by either party, which may be given at any time after the end of the first year. However, where special services are required or where the investment to serve is out of proportion to the revenue derived there from, the contract term will be as specified in the applicable contract rider or Extension of Service Agreement.

RATE SCHEDULE NO. D3.5 **COMPANY OWNED EV CHARGING SERVICE PILOT**

AVAILABILITY OF SERVICE*:* Available on an optional basis to customers for use of Company-owned electric vehicle charging equipment. The service may be offered by the Company for charging infrastructure of any kilowatt (kW) capacity at the Company's discretion. Availability shall be subject to the technical compatibility of the customer's vehicle and the charging equipment. This rate is limited to 100 individual chargers. EV charging equipment will be sited at the Company's discretion.

HOURS OF SERVICE*:* 24 hours

CURRENT, PHASE AND VOLTAGE*:* Service on this rate will be delivered at varying current, phase, and voltage subject to the technical specifications of the customer's vehicle and the EV charging equipment.

RATES*:* This service is offered as a volumetric charge at the market price of energy, and a single fixed charge encompassing all power supply capacity charges, delivery charges, and surcharges. The volumetric charge is consistent across EV charging equipment capacity. There is a separate fixed charge based on EV charging equipment capacity.

The relevant volumetric charge and session fee will be available to the customer before they choose to take service under this rate.

Volumetric Charges:	
Non-Capacity Energy Charge (on peak):	***7.754¢*** per kWh
Non-Capacity Energy Charge (off peak):	***6.902¢*** per kWh
Fixed Charges:	
Session Fee (< 200 kW charger)	$21 per vehicle-session
Session Fee (≥ 200kW charger)	$66 per vehicle-session

Surcharges and Credits*:* As approved by the Commission. See Sections C8.5 and C9.8. Those surcharges reflected on a per meter basis in Sections C8.5 and C9.8 will be converted to a volumetric equivalent for this rate schedule using the following formula: ((meter/month rate)*12 months*count of installed chargers) / total projected sales.

METERING*:* Usage on this rate will be metered at the EV charging equipment

BILLING*:* An accepted form of payment is required to take service on this rate. Customers taking service on this rate will be billed at the time of service. The billing transaction may be managed by a third-party vendor on behalf of the Company.

LATE PAYMENT CHARGE*:* Payment is required at the point-of-sale

MINIMUM CHARGE*:* The Session Fee

CONTRACT TERM*:* Effective for the period of the charging session and governing the rates, metering, and billing of the service. There is no contractual relationship between the customer and Company beyond the charging session.

(Continued on Sheet D-23.01)

RATE SCHEDULE NO. D3.11 ***GENERAL SERVICE TIME OF USE RATE***

***AVAILABILITY OF SERVICE:** Available to customers desiring service for any purpose. This rate is not available for service in conjunction with the Large General Service Rate except when used exclusively to serve electric vehicle service equipment. When exclusively serving electric vehicle service equipment, this rate may also be taken in conjunction with Rate Schedules D6.2, D8, D11, or D12. At the Company's option, service may be available to loads in excess of 1000 kW for situations where significant modifications to service facilities are not required to serve the excess load. The 1000 kW discretionary demand restriction does not apply to service provided to Electric Vehicle Fast-Charging Stations until June 1, 2026 for existing stations and for two years after beginning service for new stations. This rate will become effective no later than June 1, 2025.*

***HOURS OF SERVICE:** 24 hours.*

***CURRENT, PHASE AND VOLTAGE:** Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.*

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy (June – September)	
Summer On Peak	***4.347¢ per kWh for all kWh***
Summer Off Peak	***2.593¢ per kWh for all kWh***
Capacity Energy (October – May)	
Non-Summer On Peak	***2.774¢ per kWh for all kWh***
Non-Summer Off Peak	***2.593¢ per kWh for all kWh***
Non-Capacity Energy (June – September)	
Summer On Peak	***8.516¢ per kWh for all kWh***
Summer Off Peak	***5.079¢ per kWh for all kWh***
Non-Capacity Energy (October – May)	
Non-Summer On Peak	***5.435¢ per kWh for all kWh***
Non-Summer Off Peak	***5.079¢ per kWh for all kWh***

***On-Peak Hours:** All kWh used between 1:00PM and 5:00PM Monday through Friday.*
***Off-Peak Hours:** All other kWh used.*

Delivery Charges:

Service Charge:	***$11.25 per month***
Distribution Charge:	***5.858¢ per kWh for all kWh***

***Surcharges and Credits:** As approved by the Commission. See Sections C8.5 and C9.8.*

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

(Continued on Sheet No. D-23.03)

(Continued from Sheet No. D-23.02)

RATE SCHEDULE NO. D3.11 (Contd.) ***GENERAL SERVICE TIME OF USE RATE***

Capacity Energy (June – September)	
Summer On Peak	***4.347¢ per kWh for all kWh***
Summer Off Peak	***2.593¢ per kWh for all kWh***
Capacity Energy (October – May)	
Non-Summer On Peak	***2.774¢ per kWh for all kWh***
Non-Summer Off Peak	***2.593¢ per kWh for all kWh***

Delivery Charges:	
Service Charge:	***$11.25 per month***
Distribution Charge:	***5.858¢ per kWh for all kWh***

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

CONTRACT TERM: Upon enrollment customers are required to remain on rate for 12 months. After 12 months, open order, terminable on three days' written notice by either party.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: 12 months, terminable on three days' written notice by either party. Where special services are required, or where the investment to serve is out of proportion to the revenue derived therefrom, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available for commercial space-conditioning use. This provision is applicable to central air-conditioning and heat pump use. All other provisions of D3.11 shall apply.

RATE SCHEDULE NO. D4 **LARGE GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose, except that this rate is not available for service in conjunction with the General Service Rate.

Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Demand Charge:	$***9.73*** per kW applied to the Monthly Billing Demand
Non-Capacity Demand Charges:	$***6.93*** per kW applied to the Monthly Billing Demand
Non-Capacity Energy Charges:	***4.030¢*** per kWh for the first 200 kWh per kW of billing demand
	3.111¢ per kWh for the excess

Delivery Charges:

Service Charge:	$13.67 per month
Distribution Demand Charge:	***$23.99*** per kW applied to the Monthly Billing Demand

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Demand Charge:	$***9.73*** per kW applied to the Monthly Billing Demand

Delivery Charges:

Service Charge:	$13.67 per month
Distribution Demand Charge:	$***23.99*** per kW applied to the Monthly Billing Demand

(Continued on Sheet No. D-25.00)

RATE SCHEDULE NO. D5 **WATER HEATING SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers using hot water for sanitary purposes (other uses subject to the approval of the Company) and taking service under Residential and General Service Rate Schedules. This rate is also available to customers with solar assisted hot water heaters. Company approved waste heat reclamation systems and heat pump water heaters when used in conjunction with an approved electric water heater are also acceptable for use.

Available to customers who desire controlled water heating service to all of the heating elements of electric water heaters, the design and method of installation of which are approved by the Company as adapted to this service, taken through a separately metered circuit to which no other load except water heating may be connected. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours.

HOURS OF INTERRUPTION: Interruptions may be called for, but not limited to, system testing and evaluation, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit interruptions to intervals of no longer than 4 hours in any 24-hour period.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 240 volts, three-wire, except that, in certain city districts, alternating current service at 208 volts, nominal, three-wire, or three-phase at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Residential Power Supply Charges:
Capacity Energy Charge: ***1.914¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***2.995¢*** per kWh for all kWh

Residential Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh

Commercial Power Supply Charges:
Capacity Energy Charge: ***1.627¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***3.187¢*** per kWh for all kWh

Commercial Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

(Continued on Sheet No. D-27.00)

(Continued from Sheet No. D-26.00)

RATE SCHEDULE NO. D5 (Contd.) **WATER HEATING SERVICE RATE**

Retail Access Service Customers:
Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge*:* ***1.914¢*** per kWh for all kWh

Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE (contd):

Residential Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***8.907¢*** per kWh for all kWh

Commercial Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ***1.627¢*** per kWh for all kWh

Commercial Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

CONTRACT TERM: Open order, terminable or three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

WATER HEATER REQUIREMENTS FOR WATER HEATER RATE APPLICATION:

Rate Option	Minimum Tank Capacity*	Maximum Total Connected Load**
Residential	30 gallons	5.5 kW
Rate Option	Minimum Tank Capacity*	Maximum Total Connected Load**
Commercial	2 gallons per kW of total connected load 40 gallon minimum	Controlled by minimum tank capacity requirements

*No limitation to number of tanks
**Single or multi-element

RATE SCHEDULE NO. D6.2 **PRIMARY EDUCATIONAL INSTITUTION RATE**

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location. School shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational training, or occupational school. "College" or "University" shall mean buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Demand Charge: $***11.44*** per kW of on-peak billing demand

Voltage Level Discount:

$***0.48*** per kW at transmission level
$***0.23*** per kW at subtransmission level

Non-Capacity

Demand Charge: $***3.34*** per kW of on-peak billing demand

Voltage Level Discount:

$***0.14*** per kW at transmission level
$***0.07*** per kW at subtransmission level

Energy Charges: ***4.669¢*** per kWh for all on-peak kWh
4.369¢ per kWh for all off-peak kWh

Voltage Level Discount:

0.175¢ per kWh at transmission level
0.079¢ per kWh at subtransmission level

(Continued on Sheet No. D-36.02)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Tenth Revised Sheet No. D-36.02
Cancels Ninth Revised Sheet No. D-36.02

(Continued from Sheet No. D-36.01)

RATE SCHEDULE NO. D6.2 (Contd.) **PRIMARY EDUCATIONAL INSTITUTION RATE**

Full Service Customers (Contd):

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

Retail Access Service Customers:
Capacity (Only applicable to Retail Access Service Customers receiving utility Capacity Service from DTE Electric)

Demand Charge***:*** $***11.44*** per kW of on-peak billing demand

Voltage Level Discount:
$***0.48*** per kW of on-peak billing demand at transmission level
$***.023*** per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

(Continued on Sheet No. D-36.03)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

RATE SCHEDULE NO. D8 **INTERRUPTIBLE SUPPLY RATE**

AVAILABILITY OF SERVICE: Available to customers desiring separately metered service at primary voltage who contract for a specified quantity of demonstrated interruptible load of not less than 50 kilowatts at a single location. Contracted interruptible capacity on this rate is limited to 300 megawatts. ***Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.***

TESTING PROCEDURES: In accordance with participation in an interruptible tariff, the customer agrees to comply with Company requirements regarding testing procedures. Customer shall complete and sign an interruptible responsibility letter annually by April 1st. Failure to sign and submit the interruptible responsibility letter may result in removal from this interruptible tariff. The letter designates that the customer understands their responsibility to interrupt, has an interruption plan, and has the capability to interrupt the contracted load. In addition, the Company will conduct multiple simulations each year to verify the communication system is working properly.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet maximum interruptible requirements, but not less than 50 kilowatts. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The interruptible contract capacity shall not include any firm power capacity, except under Product Protection Provision.

CONDITIONS OF INTERRUPTION: All interruptible load served hereunder shall be subject to Capacity Deficiency Orders and System Integrity Interruption Orders.

A Capacity Deficiency Order is a pricing provision that permits a customer to choose to pay higher hourly energy rates when (a) energy prices to the Company in the Midwest ISO energy market are above the D8 energy rate and (b) the Company's available generation assets are insufficient to meet the Company's full service load. The customer has the choice of either paying higher energy rates through the non-interruption fee or avoid paying the higher energy rates by reducing or interrupting load, at the customer's discretion.

A System Integrity Interruption Order is a non-discretionary order requiring a customer to interrupt load. All interruptible load served hereunder shall be subject to interruption by the Company in order to maintain system integrity. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3.

CAPACITY DEFICIENCY ORDER:

NOTICE OF CAPACITY DEFICIENCY: The customer shall be provided at least one hour advance notice of a capacity deficiency order. This notice will include the effective start time and estimated duration of the capacity deficiency order along with an estimate of the replacement energy cost in cents per kilowatt-hour. The customer shall be provided notice of the actual end time for the capacity deficiency order.

(Continued on Sheet No. D-40.01)

(Continued from Sheet No. D-40.00)

RATE SCHEDULE NO. D8 (Contd.) **INTERRUPTIBLE SUPPLY RATE**

NON-INTERRUPTION FEE: Customers who do not interrupt by the effective start time of a capacity deficiency order shall be billed at the cost of replacement energy plus 0.576¢ per kWh during the time of interruption plus the applicable voltage level charge, but not less than the normal D8 rate. Voltage level charges for service other than transmission voltage are:

0.***139¢*** per kWh at the distribution level.
0.***077¢*** per kWh at the subtransmission level.

SYSTEM INTEGRITY INTERRUPTION ORDER:

NOTICE OF SYSTEM INTEGRITY INTERRUPTION*:* The customer shall be provided:

1) Notice at least 1 hour in advance of probable interruption, whenever possible***;***
2) The time in which customer must fully reduce load; and
3) The estimated duration of the interruption.

The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of System Integrity Interruption shall be billed at the higher of (i) the rate of $50 per kW applied to the highest 60-minute integrated interruptible demand (kW) created during the interruption period or (ii) the actual damages incurred by the Company, including any MISO penalties in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with a System Integrity interruption order may be immediately reduced by the amount the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-41.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Eleventh Revised Sheet No. D-41.00
Cancels Tenth Revised Sheet No. D-41.00

(Continued from Sheet No. D-41.00)

RATE SCHEDULE NO. D8 (Contd.) **INTERRUPTIBLE SUPPLY RATE**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:
Capacity

Demand Charge: $***4.50*** per kW of on-peak billing demand
Voltage Level Discount:
$***0.19*** per kW of on-peak billing demand at transmission level
$***0.09*** per kW of on-peak billing demand at subtransmission level

Non-Capacity
Demand Charge: $***5.62*** per kW of on-peak billing demand
Voltage Level Discount:
$***0.24*** per kW of on-peak billing demand at transmission level
$***0.11*** per kW of on-peak billing demand at subtransmission level

Energy Charge: ***4.275¢*** per kWh for all on-peak kWh
3.275¢ per kWh for all off-peak kWh

Voltage Level Discount:
0.139¢ per kWh at transmission level
0.062¢ per kWh at subtransmission level

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

(Continued on Sheet No. D-42.00)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

(Continued from Sheet No. D-41.00)

RATE SCHEDULE NO. D8 (Contd.) **INTERRUPTIBLE SUPPLY RATE**

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service customers:

Capacity (only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: $***4.50*** per kW of on-peak billing demand

Voltage Level Discount:

$***0.19*** per kW of on-peak billing demand at transmission level

$***0.09*** per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Primary Service Charge: $70 per month

Subtransmission and Transmission Service Charge: $375 per month

Distribution Charges:

For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.

For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. In no event will the monthly on-peak billing demand be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts.

(Continued on Sheet No. D-43.00)

(Continued from Sheet No. D-44.00)

RATE SCHEDULE NO. D9 **OUTDOOR PROTECTIVE LIGHTING**

SPECIAL TERMS AND CONDITIONS (contd.):

The stated charges for underground service on Sheet No. D-46.00 cover the ordinary trenching for cable extensions under normal soil conditions in cleared areas.

(1) Special purpose facilities are considered to be line or cable extensions, transformers, and any additional poles without lights, excluding facilities provided under stated charges on Sheet No. D-45.00. Where special purpose facilities are required, a service charge of 18% per year on the investment in such facilities will be billed in installments as an addition to the regular rate for each light. In the event the customer discontinues service before the end of the contract term, the established rate as well as the service charge on special purpose facilities for the remaining portion of the contract term shall immediately become due and payable. This provision was closed to new installations as of January 22, 1994.
(2) For new installations after January 22, 1994, which require investment in excess of three times the annual revenue, this rate is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation.
(3) For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue, the customer may elect to pay a post charge for each increment of $1,000 investment required above three times the annual revenue.
(4) As an alternative, where the required contribution exceeds $10,000, upon agreement of the customer and the Company, the customer will pay an additional annual charge of the Company's weighted average cost of capital (***7.05***%) times the contribution amount in lieu of the cash contribution.

DE-ENERGIZED LIGHTS: Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 60% of the regular yearly rates. A $35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.

DUSK TO MIDNIGHT SERVICE: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied. One control per circuit or luminaire will be provided.

EXPERIMENTAL PROGRAMMABLE PHOTOCELL SERVICE: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied.

MONTHLY RATES: Overhead Outdoor Protective Lighting with Existing Pole and Existing Secondary Facilities ***(***All-night service***)***.

Power Supply Charges:

Capacity Energy Charge:	0.00***¢*** per kWh for all kWh
Non-Capacity Energy Charge***:***	***4.61¢*** per kWh for all kWh

(Continued on Sheet No. D-45.01)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Eighth Revised Sheet No. D-45.01
Cancels Seventh Revised Sheet No. D-45.01

(Continued from Sheet No. D-45.00)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
100 W	Mercury Vapor	***$14.34***	120	350	***$0.0461***	***$1.93***	***$16.28***
175 W	Mercury Vapor	***$19.51***	210	350	***$0.0461***	***$3.39***	***$22.90***
250 W	Mercury Vapor	***$23.34***	300	350	***$0.0461***	***$4.84***	***$28.18***
400 W	Mercury Vapor	***$30.78***	450	350	***$0.0461***	***$7.26***	***$38.03***
1,000 W	Mercury Vapor	***$62.71***	1060	350	***$0.0461***	***$17.09***	***$79.80***
100 W	High Pressure Sodium	***$14.61***	135	350	***$0.0461***	***$2.18***	***$16.79***
150 W	High Pressure Sodium	***$17.46***	200	350	***$0.0461***	***$3.22***	***$20.69***
250 W	High Pressure Sodium	***$22.48***	305	350	***$0.0461***	***$4.92***	***$27.40***
400 W	High Pressure Sodium	***$27.69***	465	350	***$0.0461***	***$7.50***	***$35.19***
1,000 W	High Pressure Sodium	***$55.87***	1100	350	***$0.0461***	***$17.74***	***$73.61***
100 W	Metal Halide	***$12.24***	120	350	***$0.0461***	***$1.93***	***$14.18***
150 W	Metal Halide	***$15.68***	180	350	***$0.0461***	***$2.90***	***$18.58***
175 W	Metal Halide	***$17.40***	210	350	***$0.0461***	***$3.39***	***$20.79***
250 W	Metal Halide	***$22.56***	300	350	***$0.0461***	***$4.84***	***$27.40***
320 W	Metal Halide	***$26.29***	365	350	***$0.0461***	***$5.88***	***$32.18***
400 W	Metal Halide	***$31.74***	460	350	***$0.0461***	***$7.42***	***$39.16***
1,000 W	Metal Halide	***$65.57***	1050	350	***$0.0461***	***$16.93***	***$82.50***
20 - 29 W	LED	***$11.93***	25	350	***$0.0461***	***$0.40***	***$12.33***
30 - 39 W	LED	***$12.26***	35	350	***$0.0461***	***$0.56***	***$12.83***
40 - 49 W	LED	***$13.06***	45	350	***$0.0461***	***$0.73***	***$13.78***
50 - 59 W	LED	***$13.48***	55	350	***$0.0461***	***$0.89***	***$14.37***
60 - 69 W	LED	***$14.09***	65	350	***$0.0461***	***$1.05***	***$15.13***
70 - 79 W	LED	***$14.70***	75	350	***$0.0461***	***$1.21***	***$15.91***
80 - 89 W	LED	***$15.31***	85	350	***$0.0461***	***$1.37***	***$16.68***
90 - 99 W	LED	***$15.89***	95	350	***$0.0461***	***$1.53***	***$17.42***
100 - 109 W	LED	***$16.45***	105	350	***$0.0461***	***$1.69***	***$18.15***
110 - 119 W	LED	***$17.15***	115	350	***$0.0461***	***$1.85***	***$19.00***
120 - 129 W	LED	***$17.58***	125	350	***$0.0461***	***$2.02***	***$19.60***
130 - 139 W	LED	***$18.36***	135	350	***$0.0461***	***$2.18***	***$20.54***
140 - 149 W	LED	***$18.92***	145	350	***$0.0461***	***$2.34***	***$21.26***
150 - 159 W	LED	***$19.28***	155	350	***$0.0461***	***$2.50***	***$21.78***
160 - 169 W	LED	***$19.85***	165	350	***$0.0461***	***$2.66***	***$22.51***
170 - 179 W	LED	***$20.41***	175	350	***$0.0461***	***$2.82***	***$23.23***
180 - 189 W	LED	***$20.98***	185	350	***$0.0461***	***$2.98***	***$23.96***
190 - 199 W	LED	***$21.54***	195	350	***$0.0461***	***$3.14***	***$24.69***
200 - 209 W	LED	***$22.21***	205	350	***$0.0461***	***$3.31***	***$25.52***
210 - 219 W	LED	***$22.76***	215	350	***$0.0461***	***$3.47***	***$26.22***
220 - 229 W	LED	***$23.30***	225	350	***$0.0461***	***$3.63***	***$26.93***
230 - 239 W	LED	***$23.86***	235	350	***$0.0461***	***$3.79***	***$27.65***
240 - 249 W	LED	***$24.37***	245	350	***$0.0461***	***$3.95***	***$28.32***

(Continued on Sheet No. D-45.02)

(Continued from Sheet No. D-45.01)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

Luminaire Charges (Contd)**:**

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
250 - 259 W	LED	***$24.94***	255	350	***$0.0461***	***$4.11***	***$29.05***
260 - 269 W	LED	***$25.50***	265	350	***$0.0461***	***$4.27***	***$29.78***
270 - 279 W	LED	***$26.07***	275	350	***$0.0461***	***$4.43***	***$30.50***
280 - 289 W	LED	***$26.61***	285	350	***$0.0461***	***$4.59***	***$31.20***
290 - 299 W	LED	***$27.15***	295	350	***$0.0461***	***$4.76***	***$31.91***
300 - 309 W	LED	***$27.76***	305	350	***$0.0461***	***$4.92***	***$32.68***
310 - 319 W	LED	***$28.33***	315	350	***$0.0461***	***$5.08***	***$33.41***
320 - 329 W	LED	***$28.90***	325	350	***$0.0461***	***$5.24***	***$34.14***
330 - 339 W	LED	***$29.46***	335	350	***$0.0461***	***$5.40***	***$34.86***
340 - 349 W	LED	***$30.03***	345	350	***$0.0461***	***$5.56***	***$35.59***
350 - 359 W	LED	***$30.59***	355	350	***$0.0461***	***$5.72***	***$36.32***
360 - 369 W	LED	***$31.16***	365	350	***$0.0461***	***$5.88***	***$37.04***
370 - 379 W	LED	***$31.72***	375	350	***$0.0461***	***$6.05***	***$37.77***
380 - 389 W	LED	***$32.29***	385	350	***$0.0461***	***$6.21***	***$38.50***
390 - 399 W	LED	***$32.64***	395	350	***$0.0461***	***$6.37***	***$39.00***

For installations prior to January 22, 1994. New Pole and Single Span of Secondary Facilities. The above rate plus $24.48 per pole per year.

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Multiple Lamps on a Single Pole. For each additional luminaire added to the same pole the charge will be at the existing pole rate.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those fixtures fail. At that time, the luminaire will be converted to LED.

MONTHLY RATES: Underground Outdoor Protective Lighting with Lamp Spacing up to 120 Feet (All-night service).

Power Supply Charges:
Capacity Energy Charge***:*** 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.61¢*** per kWh for all kWh

(Continued on Sheet No. D-46.00)

(Continued from Sheet No. D-45.02)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

Luminaire Charges (Contd)**:**

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
100 W	Mercury Vapor	***$26.74***	120	350	***$0.0461***	***$1.93***	***$28.68***
175 W	Mercury Vapor	***$29.37***	210	350	***$0.0461***	***$3.39***	***$32.75***
250 W	Mercury Vapor	***$34.47***	300	350	***$0.0461***	***$4.84***	***$39.30***
400 W	Mercury Vapor	***$44.68***	450	350	***$0.0461***	***$7.26***	***$51.94***
1,000 W	Mercury Vapor	***$77.75***	1060	350	***$0.0461***	***$17.09***	***$94.84***
70 W	High Pressure Sodium	***$23.35***	95	350	***$0.0461***	***$1.53***	***$24.88***
100 W	High Pressure Sodium	***$24.07***	135	350	***$0.0461***	***$2.18***	***$26.25***
150 W	High Pressure Sodium	***$25.95***	200	350	***$0.0461***	***$3.22***	***$29.18***
250 W	High Pressure Sodium	***$28.73***	305	350	***$0.0461***	***$4.92***	***$33.65***
400 W	High Pressure Sodium	***$32.89***	465	350	***$0.0461***	***$7.50***	***$40.39***
1,000 W	High Pressure Sodium	***$49.51***	1100	350	***$0.0461***	***$17.74***	***$67.25***
100 W	Metal Halide	***$10.99***	120	350	***$0.0461***	***$1.93***	***$12.92***
150 W	Metal Halide	***$16.48***	180	350	***$0.0461***	***$2.90***	***$19.38***
175 W	Metal Halide	***$19.23***	210	350	***$0.0461***	***$3.39***	***$22.61***
250 W	Metal Halide	***$27.47***	300	350	***$0.0461***	***$4.84***	***$32.30***
400 W	Metal Halide	***$42.11***	460	350	***$0.0461***	***$7.42***	***$49.53***
1,000 W	Metal Halide	***$96.13***	1050	350	***$0.0461***	***$16.93***	***$113.06***
20 - 29 W	LED	***$24.48***	25	350	***$0.0461***	***$0.40***	***$24.88***
30 - 39 W	LED	***$24.90***	35	350	***$0.0461***	***$0.56***	***$25.47***
40 - 49 W	LED	***$25.42***	45	350	***$0.0461***	***$0.73***	***$26.15***
50 - 59 W	LED	***$25.76***	55	350	***$0.0461***	***$0.89***	***$26.64***
60 - 69 W	LED	***$26.19***	65	350	***$0.0461***	***$1.05***	***$27.24***
70 - 79 W	LED	***$26.58***	75	350	***$0.0461***	***$1.21***	***$27.79***
80 - 89 W	LED	***$26.99***	85	350	***$0.0461***	***$1.37***	***$28.36***
90 - 99 W	LED	***$27.39***	95	350	***$0.0461***	***$1.53***	***$28.92***
100 - 109 W	LED	***$27.78***	105	350	***$0.0461***	***$1.69***	***$29.47***
110 - 119 W	LED	***$28.19***	115	350	***$0.0461***	***$1.85***	***$30.05***
120 - 129 W	LED	***$28.45***	125	350	***$0.0461***	***$2.02***	***$30.46***
130 - 139 W	LED	***$28.96***	135	350	***$0.0461***	***$2.18***	***$31.13***
140 - 149 W	LED	***$29.20***	145	350	***$0.0461***	***$2.34***	***$31.54***
150 - 159 W	LED	***$29.58***	155	350	***$0.0461***	***$2.50***	***$32.08***
160 - 169 W	LED	***$29.96***	165	350	***$0.0461***	***$2.66***	***$32.62***
170 - 179 W	LED	***$30.34***	175	350	***$0.0461***	***$2.82***	***$33.16***
180 - 189 W	LED	***$30.72***	185	350	***$0.0461***	***$2.98***	***$33.70***
190 - 199 W	LED	***$31.09***	195	350	***$0.0461***	***$3.14***	***$34.24***
200 - 209 W	LED	***$31.51***	205	350	***$0.0461***	***$3.31***	***$34.82***
210 - 219 W	LED	***$31.85***	215	350	***$0.0461***	***$3.47***	***$35.32***
220 - 229 W	LED	***$32.23***	225	350	***$0.0461***	***$3.63***	***$35.86***
230 - 239 W	LED	***$32.61***	235	350	***$0.0461***	***$3.79***	***$36.40***
240 - 249 W	LED	***$32.98***	245	350	***$0.0461***	***$3.95***	***$36.93***
250 - 259 W	LED	***$33.36***	255	350	***$0.0461***	***$4.11***	***$37.47***
260 - 269 W	LED	***$33.74***	265	350	***$0.0461***	***$4.27***	***$38.01***

(Continued on Sheet No. D-46.01)

(Continued from Sheet No. D-46.00)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

Luminaire Charges (Contd)**:**

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
270 - 279 W	LED	***$34.07***	275	350	***$0.0461***	***$4.43***	***$38.51***
280 - 289 W	LED	***$34.44***	285	350	***$0.0461***	***$4.59***	***$39.03***
290 - 299 W	LED	***$34.80***	295	350	***$0.0461***	***$4.76***	***$39.56***
300 - 309 W	LED	***$35.25***	305	350	***$0.0461***	***$4.92***	***$40.17***
310 - 319 W	LED	***$35.63***	315	350	***$0.0461***	***$5.08***	***$40.71***
320 - 329 W	LED	***$36.01***	325	350	***$0.0461***	***$5.24***	***$41.25***
330 - 339 W	LED	***$36.39***	335	350	***$0.0461***	***$5.40***	***$41.79***
340 - 349 W	LED	***$36.77***	345	350	***$0.0461***	***$5.56***	***$42.33***
350 - 359 W	LED	***$37.14***	355	350	***$0.0461***	***$5.72***	***$42.87***
360 - 369 W	LED	***$37.52***	365	350	***$0.0461***	***$5.88***	***$43.41***
370 - 379 W	LED	***$37.90***	375	350	***$0.0461***	***$6.05***	***$43.95***
380 - 389 W	LED	***$38.28***	385	350	***$0.0461***	***$6.21***	***$44.49***
390 - 399 W	LED	***$38.66***	395	350	***$0.0461***	***$6.37***	***$45.03***

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Effective May 1, 2019, installations requiring additional facilities shall pay a post charge of $***7.08*** per increment of $1,000 of expense in lieu of contribution in aid of construction. Contribution is described in paragraph (3) above.

Long Span

- For lamp spacing over 120 feet up to 325 feet on the same side of street, add to rate per lamp per year $24.48

Semi-Ornamental

- For Semi-Ornamental Systems which employ Ornamental Post Units served from overhead conductors, where such construction is practical, reduce rate per luminaire per year $21.48

Multiple Luminaires on a Single Pole

- For additional luminaires added to the same pole, a reduced rate per luminaire per year on the added luminaire.
  Ornamental $97.92
  Ornamental-Lamp spacing over 120 feet $122.40
  Semi-Ornamental $76.56

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, the luminaire will be converted to LED.

RATE SCHEDULE NO. D10 **ALL-ELECTRIC SCHOOL BUILDING SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service in school buildings served at primary voltage who contract for a specified installed capacity of not less than 50 kilowatts at a single location provided the space heating and water heating for all or a substantial portion of the premises is supplied by electric service and is installed on a permanent basis.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800 or 13,200 volts at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charge (June through October):	***3.586¢*** per kWh for all kWh
Energy Charge (November through May):	***1.573¢*** per kWh for all kWh

Non-Capacity

Energy Charge (June through October):	***5.993¢*** per kWh for all kWh
Energy Charge (November through May):	***5.993¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$70 per month
Distribution Charge:	***1.870¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charge (June through October):	***3.586¢*** per kWh for all kWh
Energy Charge (November through May):	***1.573¢*** per kWh for all kWh

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge:	$70 per month
Distribution Charge:	***1.870¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-48.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Tenth Revised Sheet No. D-48.01
Cancels Ninth Revised Sheet No. D-48.01

RATE SCHEDULE NO. D11 **PRIMARY SUPPLY RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:
Full Service Customers:
Power Supply Charges:
Capacity
Demand Charge: $***9.74*** per kW of on-peak billing demand
Voltage Level Discount:
$***0.41*** per kW of on-peak billing demand at transmission level
$***0.20*** per kW of on-peak billing demand at subtransmission level

Non-Capacity
Demand Charge***:*** $***7.25*** per kW of on-peak billing demand
Voltage Level Discount:
$***0.31*** per kW of on-peak billing demand at transmission level
$***0.15*** per kW of on-peak billing demand at subtransmission level
Energy Charge: ***4.275¢*** per kWh for all on-peak kWh
3.275¢ per kWh for all off-peak kWh

Voltage Level Discount:
0.139¢ per kWh at transmission level
0.062¢ per kWh at subtransmission level

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month

Distribution Charges:
For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Continued on Sheet No. D-48.02)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

(Continued from Sheet No. D-48.01)

RATE SCHEDULE NO. D11 (Contd.) **PRIMARY SUPPLY RATE**

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: $***9.74*** per kW of on-peak billing demand
Voltage Level Discount:
$***0.41*** per kW of on-peak billing demand at transmission level
$***0.20*** per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

Delivery Charges:

Primary Service Charge: $70 per month
Subtra***n***smission and Transmission Service Charge: $375 per month

Distribution Charges:

For primary service (less than 24 kV) $***6.32*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. The monthly on- peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during

(Continued on Sheet No. D-48.03)

RATE SCHEDULE NO. D12

EXPERIMENTAL LARGE CUSTOMER LOW PEAK DEMAND SUPPLY RATE

AVAILABILITY OF SERVICE: Available on an experimental basis to new full-service customers with a minimum metered contract capacity of 10,000 kW and with high on-peak demands set during the October through May billing months and on-peak demands of ten percent (10%) or less during the June through September billing months and taking service at sub-transmission, or transmission voltage at a single location. Total contracted capacity on this tariff is limited to 100 MW. Service under this tariff may not be combined with any other tariff, rider, or separately metered service except for Rider Nos. 17 or 19.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 10,000 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity (October through May)
Demand Charge: $0.32 per kW of on-peak billing demand

Capacity (June through September)
Demand Charge: $***8.04*** per kW of on-peak billing demand

Capacity Voltage Level Discount:
$(0.005) per kW of on-peak billing demand at transmission level (October through May)
$(0.14) per kW of on-peak billing demand at transmission level (June through September)

Non-Capacity (October through May)
Demand Charge: $0.32 per kW of on-peak billing demand

Non-Capacity (June through September)
Demand Charge: $***41.37*** per kW of on-peak billing demand

Non-Capacity Voltage Level Discount:
$(0.005) per kW of on-peak billing demand at transmission level (October through May)
$(0.70) per kW of on-peak billing demand at transmission level (June through September)

(Continued on Sheet No. D-48.06)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Third Revised Sheet No. D-48.06
Cancels Second Revised Sheet No. D-48.06

(Continued from Sheet No. D-48.05)

RATE SCHEDULE NO. D12 (contd.)

EXPERIMENTAL LARGE CUSTOMER LOW PEAK DEMAND SUPPLY RATE

Energy Charge: ***4.133¢*** per kWh for all on-peak kWh
3.630¢ per kWh for all off-peak kWh

Energy Voltage Level Discount: (0.056)¢ per kWh at transmission level

Delivery Charges:
Subtransmission Service Charge: $375 per month
Transmission Service Charge: $375 per month

Distribution Charges:
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand.
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period, but not less than 50 kilowatts.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.

MINIMUM CHARGE: All applicable demand charges plus the service charge and any applicable per meter per month surcharges.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

(Continued on Sheet No. D-48.07)

RATE SCHEDULE NO. D13 **XL HIGH LOAD FACTOR RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50,000 kilowatts, which may be located at one or more sites within the Company's electric service territory. The customer's load must reflect the following characteristics:

1) The contract capacity under this schedule must be new and incremental. Existing ("baseline") usage will remain eligible for service under any other rate schedule or rider for which it qualifies. The required incremental contracted capacity must be in service within four years of initially taking service under this rate.
2) Service taken by the customer must be at a load factor of no less than 75% for the capacity contracted under this rate. The required incremental load factor must be demonstrated in the twelve months following achievement of the contracted capacity described in (1) and maintained for the duration of service on this rate.
3) Any customer site taking service under this rate shall require separately metered circuits for such service.
4) Any customer failing to meet the incremental contract capacity and load factor requirement will be removed from this rate and placed on an eligible rate of the customer's choosing.
5) The rate is available at the discretion of the Company.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in megawatts sufficient to meet normal maximum requirements but not less than 50,000 kilowatts. The customer may not exceed the contract capacity by more than 5%. Demand in excess of 105% of contract capacity will be placed on Rate Schedule No. D11, or any other eligible rate at the election of the customer. At the Company's discretion, it may offer to increase contract capacity on this rate without effect on the term of the contract. The contract capacity for customers served at more than one voltage level at one site shall be the sum of the contract capacities established for each voltage level.

The contract capacity, however established, shall not be decreased during the term of the contract except by mutual consent, and in no event may a decrease in contract capacity result in less than the minimum required capacity or load factor.

RATES:

Power Supply Charges for all service voltages	
Capacity	$15.14 / MWh
Non-Capacity	$***32.87*** / MWh
Transmission	$***3.08*** / MWh
Delivery Charge	
Primary Service Charge	$70 per meter/month
Subtransmission and Transmission Service Charge	$375 per meter/month

(Continued on Sheet No. D-48.09)

(Continued from Sheet No. D-48.08)

RATE SCHEDULE NO. D13 (contd.) **XL HIGH LOAD FACTOR RATE**

RATES (contd.)**:**

Distribution Charges

For primary service (less than 24 kV)	$***9.61*** / MWh
For service at sub-transmission voltage (24 to 41.6 kV)	$***2.63*** / MWh
For service at transmission voltage (120 kV and above)	$***1.42*** / MWh

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.55 per MWh shall be applied to the contracted load on this rate. A credit of $0.40 per MWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Administration Charge

Administration	$0.15 / MWh

Surcharges and Credits: Customers are subject to surcharges as approved by the Commission. Customers taking service on this rate are not subject to the Power Supply Cost Recovery (PSCR) factor, the Nuclear Surcharge, or the Transitional Reconciliation Mechanism. Customers taking service on this rate will be subject to an adjustment to reconcile projected and actual power supply non-capacity and transmission costs.

Other: The power supply capacity charge shall remain fixed for the term of the contract

BASELINE USAGE: Baseline usage is the Customer's existing contracted capacity at the time of taking service on D13. The Company reserves the right to define baseline usage based on exceptional circumstances as appropriate. Baseline usage may be served on any eligible rate schedule or rider, and it may in the future take service under any eligible rate or rider. No capacity or energy defined as baseline is eligible for service under this rate schedule and no capacity or energy may be moved from a baseline usage circuit to a circuit served under this rate.

DEFINITION OF LOAD FACTOR: For the purposes of this rate schedule Load Factor is defined on an annual basis. It is calculated as:

(Total MWh of usage in year / (incremental contract capacity in MW*hours in year))

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Any power factor less than 70% will not be permitted and the customer will be required to install at his own expense such corrective equipment as may be necessary to improve power factor. A penalty will be applied to the total amount of the monthly billing for electric energy for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The Power Factor Clause will be applied to metered quantities.

(Continued on Sheet No. D-48.10)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Original Sheet No. D-48.11

RATE SCHEDULE NO. D14 ***PRIMARY TOU***

***AVAILABILITY OF SERVICE:** Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location. Contracted capacity on this rate is limited to 50 MW. This rate will be effective no later than December 31, 2025.*

***HOURS OF SERVICE:** 24 hours, subject to interruption by agreement, or by advance notice.*

***CURRENT, PHASE AND VOLTAGE:** Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.*

***CONTRACT CAPACITY:** Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.*

RATE PER MONTH:
Full Service Customers:
Power Supply Charges:

Capacity Energy	***(June – September)***	
Summer On Peak		***2.81¢ per kWh for all kWh***
Summer Off Peak		***1.672¢ per kWh for all kWh***
Capacity Energy	***(October – May)***	
Non-Summer On Peak		***1.942¢ per kWh for all kWh***
Non-Summer Off Peak		***1.672¢ per kWh for all kWh***

Capacity Voltage Level Discount:
0.072¢ per kWh at transmission level
0.032¢ per kWh at subtransmission level

Non-Capacity Energy	***(June – September)***	
Summer On Peak		***7.533¢ per kWh for all kWh***
Summer Off Peak		***4.483¢ per kWh for all kWh***
Non-Capacity Energy	***(October – May)***	
Non-Summer On Peak		***5.207¢ per kWh for all kWh***
Non-Summer Off Peak		***4.483¢ per kWh for all kWh***

Non-Capacity Voltage Level Discount:
0.192¢ per kWh at transmission level
0.086¢ per kWh at subtransmission level

Delivery Charges:
Primary Service Charge: ***$70 per month***
Subtransmission and Transmission Service Charge: ***$375 per month***

Continued on Sheet No. D-48.12)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

(Continued from Sheet No. D-48.11)

RATE SCHEDULE NO. D14 ***PRIMARY TOU***

Distribution Charges:

For primary service (less than 24 kV) $6.32 per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $1.73 per kW of maximum demand.
For service at transmission voltage (120 kV and above) $0.93 per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Capacity Energy	***(June – September)***	
Summer On Peak		***2.810¢ per kWh for all kWh***
Summer Off Peak		***1.672¢ per kWh for all kWh***
Capacity Energy	***(October – May)***	
Non-Summer On Peak		***1.942¢ per kWh for all kWh***
Non-Summer Off Peak		***1.672¢ per kWh for all kWh***

Capacity Voltage Level Discount:

0.072¢ per kWh at transmission level
0.032¢ per kWh at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

Delivery Charges:

Primary Service Charge: $70 per month
Subtrassmission and Transmission Service Charge: $375 per month

Distribution Charges:

For primary service (less than 24 kV) $6.32 per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $1.73 per kW of maximum demand.
For service at transmission voltage (120 kV and above) $0.93 per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

(Continued on Sheet No. D-48.13)

(Continued from Sheet No. D-48.12)

RATE SCHEDULE NO. D14 ***PRIMARY TOU***

***Surcharges and Credits:** As approved by the Commission. See Section C9.8.*

***LATE PAYMENT CHARGE:** See Section C4.8.*

***DEFINITION OF CUSTOMER VOLTAGE LEVEL:** See Section C13.*

***MAXIMUM DEMAND:** The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.*

***MINIMUM CHARGE:** All applicable demand charges plus the service charge and any applicable per meter per month surcharges.*

***SCHEDULE OF ON-PEAK HOURS:** See Section C11.*

POWER FACTOR CLAUSE:

Full Service Customers:

The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Any power factor less than 70% will not be permitted and the customer will be required to install at his own expense such corrective equipment as may be necessary to improve power factor. A penalty will be applied to the total amount of the monthly billing for electric energy for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The Power Factor Clause shall not be applied to the on-peak billing demand ratchet nor to the minimum contract demand, but will be applied to metered quantities.

Retail Access Service Customers:

A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location's single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of $3.50/kVAR will be applied to excess Reactive Demand.

***SPECIAL TERMS AND CONDITIONS:** The contract capacity however established shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a specific reduction in connected load.*

Customer-owned equipment must be operated so that voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.

Customers will be permitted to transfer from this rate to a secondary commercial rate, provided they can meet the availability requirements, if the load characteristic changes sufficiently so that the customer would benefit by the change for the foreseeable future even though metering was continued at primary voltage. Frequent changes, however, from one rate to another for a period less than one full year will not be permitted in accordance with Section C4.4 - Choice of Rates.

(Continued on Sheet No. D-48.14)

(Continued from Sheet No. D-48.13)

RATE SCHEDULE NO. D14 ***PRIMARY TOU***

SPECIAL TERMS AND CONDITIONS (Contd.)

For example, during the period that a building is under construction, primary service may be supplied and metered at primary voltage and billed on a secondary rate while the building is under the jurisdiction of the contractor.

Also, for the convenience of the utility, service to a large school complex or a high rise building where, as a matter of design, primary voltage is furnished with Company owned transformers at remote locations fed by customer owned primary cables, the account can be billed on a secondary rate though metered at one central primary voltage location at or near the termination of the utility-owned cables.

At the option of the Company, service may be supplied at the primary voltage and metered at a secondary voltage when the customer transfers from a secondary rate. For loads metered at a secondary voltage (less than 600V), all measured quantities shall be increased by 2%.

CONTRACT TERM: For new primary installations over 1000 kW the term is for not less than five years, extending thereafter from month-to-month until terminated by mutual consent or on twelve months' written notice by either party, which may be given at any time after the end of the fourth year. For new primary installations of 1000 kW or less and for new customers at existing installations, the term is for three years which under special circumstances may be increased or reduced at the discretion of the Company, extending thereafter from month-to-month until terminated by mutual consent or on one month written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

(Continued from Sheet No. D-49.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

CONTRACT TERM: Minimum 5 year term. Upon expiration of the initial term shall continue on a month-to-month basis until terminated by mutual written consent of the parties or by either party with thirty (30) days prior written notice to the other party. Any conversion, relocation and/or removal of existing street lighting facilities at the customer's request, including those removals necessitated by termination of service, must be paid for by the customer. The detailed provisions and schedule of charges, which may include the remaining value of the existing facilities, will be quoted upon request. The Company shall not withdraw service, and the municipality shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

Option I: Company Owned Street Lighting System

Where new installations require an investment in excess of an investment allowance, Option I is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation. (Effective January 1, 1991, the investment amount will be limited to direct cost. Effective January 1, 1992, the investment amount will include full cost.)

As an alternative, where the required contribution exceeds $10,000, upon agreement of the customer and the Company, the customer will pay an additional annual charge of the Company's weighted average cost of capital (***7.05***%) times the contribution amount in lieu of the cash contribution.

For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue at the prevailing rate at the time of installation, the customer may elect to pay a post charge for each increment of $1,000 investment required above three times the annual revenue.

DE-ENERGIZED LIGHTS: Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 60% of the regular yearly rates. A $35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.

DUSK TO MIDNIGHT SERVICE: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied. One control per circuit or luminaire will be provided.

EXPERIMENTAL PROGRAMMABLE PHOTOCELL SERVICE: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours on use will be applied.

MONTHLY RATES OPTION I: Overhead Municipal Street Lighting *(*All-night service*)*.

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge***: 4.61¢*** per kWh for all kWh

(Continued on Sheet No. D-50.01)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Seventh Revised Sheet No. D-50.01
Cancels Sixth Revised Sheet No. D-50.01

(Continued from Sheet No. D-50.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
100 W	Mercury Vapor	$26.79	120	350	$0.0461	$1.93	$28.73
175 W	Mercury Vapor	$33.17	210	350	$0.0461	$3.39	$36.55
250 W	Mercury Vapor	$40.61	300	350	$0.0461	$4.84	$45.45
400 W	Mercury Vapor	$52.47	450	350	$0.0461	$7.26	$59.73
1,000 W	Mercury Vapor	$100.17	1060	350	$0.0461	$17.09	$117.26
70 W	High Pressure Sodium	$19.94	95	350	$0.0461	$1.53	$21.47
100 W	High Pressure Sodium	$22.77	135	350	$0.0461	$2.18	$24.95
150 W	High Pressure Sodium	$27.72	200	350	$0.0461	$3.22	$30.95
250 W	High Pressure Sodium	$35.59	305	350	$0.0461	$4.92	$40.50
360 W	High Pressure Sodium	$44.02	418	350	$0.0461	$6.74	$50.75
400 W	High Pressure Sodium	$47.53	465	350	$0.0461	$7.50	$55.03
1,000 W	High Pressure Sodium	$94.99	1100	350	$0.0461	$17.74	$112.73
70 W	Metal Halide	$25.87	85	350	$0.0461	$1.37	$27.24
100 W	Metal Halide	$26.25	120	350	$0.0461	$1.93	$28.19
150 W	Metal Halide	$32.45	180	350	$0.0461	$2.90	$35.35
175 W	Metal Halide	$34.73	210	350	$0.0461	$3.39	$38.12
250 W	Metal Halide	$43.22	300	350	$0.0461	$4.84	$48.05
320 W	Metal Halide	$51.12	365	350	$0.0461	$5.88	$57.00
400 W	Metal Halide	$58.78	460	350	$0.0461	$7.42	$66.20
1,000 W	Metal Halide	$121.38	1050	350	$0.0461	$16.93	$138.31
20 - 29 W	LED	$15.80	25	350	$0.0461	$0.40	$16.20
30 - 39 W	LED	$16.62	35	350	$0.0461	$0.56	$17.18
40 - 49 W	LED	$17.73	45	350	$0.0461	$0.73	$18.46
50 - 59 W	LED	$18.98	55	350	$0.0461	$0.89	$19.87
60 - 69 W	LED	$20.24	65	350	$0.0461	$1.05	$21.29
70 - 79 W	LED	$21.50	75	350	$0.0461	$1.21	$22.71
80 - 89 W	LED	$22.77	85	350	$0.0461	$1.37	$24.14
90 - 99 W	LED	$24.03	95	350	$0.0461	$1.53	$25.56
100 - 109 W	LED	$25.29	105	350	$0.0461	$1.69	$26.98
110 - 119 W	LED	$26.55	115	350	$0.0461	$1.85	$28.40
120 - 129 W	LED	$27.81	125	350	$0.0461	$2.02	$29.83
130 - 139 W	LED	$28.36	135	350	$0.0461	$2.18	$30.53
140 - 149 W	LED	$29.41	145	350	$0.0461	$2.34	$31.75
150 - 159 W	LED	$30.47	155	350	$0.0461	$2.50	$32.97
160 - 169 W	LED	$31.53	165	350	$0.0461	$2.66	$34.19

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

(Continued on Sheet No. D-50.02)

(Continued from Sheet No. D-50.01)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
170 - 179 W	LED	*$32.59*	175	350	*$0.0461*	*$2.82*	*$35.41*
180 - 189 W	LED	*$33.56*	185	350	*$0.0461*	*$2.98*	*$36.54*
190 - 199 W	LED	*$33.44*	195	350	*$0.0461*	*$3.14*	*$36.59*
200 - 209 W	LED	*$35.39*	205	350	*$0.0461*	*$3.31*	*$38.70*
210 - 219 W	LED	*$36.30*	215	350	*$0.0461*	*$3.47*	*$39.77*
220 - 229 W	LED	*$36.32*	225	350	*$0.0461*	*$3.63*	*$39.94*
230 - 239 W	LED	*$36.92*	235	350	*$0.0461*	*$3.79*	*$40.71*
240 - 249 W	LED	*$37.81*	245	350	*$0.0461*	*$3.95*	*$41.76*
250 - 259 W	LED	*$38.70*	255	350	*$0.0461*	*$4.11*	*$42.82*
260 - 269 W	LED	*$40.15*	265	350	*$0.0461*	*$4.27*	*$44.42*
270 - 279 W	LED	*$41.10*	275	350	*$0.0461*	*$4.43*	*$45.54*
280 - 289 W	LED	*$41.36*	285	350	*$0.0461*	*$4.59*	*$45.96*
290 - 299 W	LED	*$42.25*	295	350	*$0.0461*	*$4.76*	*$47.01*
300 - 309 W	LED	*$43.14*	305	350	*$0.0461*	*$4.92*	*$48.06*
310 - 319 W	LED	*$44.93*	315	350	*$0.0461*	*$5.08*	*$50.01*
320 - 329 W	LED	*$44.92*	325	350	*$0.0461*	*$5.24*	*$50.16*
330 - 339 W	LED	*$46.85*	335	350	*$0.0461*	*$5.40*	*$52.25*
340 - 349 W	LED	*$47.81*	345	350	*$0.0461*	*$5.56*	*$53.37*
350 - 359 W	LED	*$48.76*	355	350	*$0.0461*	*$5.72*	*$54.49*
360 - 369 W	LED	*$49.72*	365	350	*$0.0461*	*$5.88*	*$55.61*
370 - 379 W	LED	*$50.68*	375	350	*$0.0461*	*$6.05*	*$56.73*
380 - 389 W	LED	*$51.64*	385	350	*$0.0461*	*$6.21*	*$57.84*
390 - 399 W	LED	*$52.59*	395	350	*$0.0461*	*$6.37*	*$58.96*

Multiple Lamps on a Single Pole

- For each additional luminaire added to the same pole, reduce rate per lamp per year on the added luminaire $12.24.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, the luminaire will be converted to LED.

(Continued on Sheet No. D-51.00)

(Continued from Sheet No. D-50.02)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Option I: Company Owned Street Lighting System (Contd.)

MONTHLY RATES OPTION I: Ornamental Underground Municipal Street Lighting for Lamp Spacing up to 120 Feet of Street ***(***All-night service***)***.

Power Supply Charges:
Capacity Energy Charge***:*** 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge***:*** ***4.61¢*** per kWh for all kWh

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
100 W	Mercury Vapor	***$32.39***	120	350	***$0.0461***	***$1.93***	***$34.32***
175 W	Mercury Vapor	***$37.49***	210	350	***$0.0461***	***$3.39***	***$40.88***
250 W	Mercury Vapor	***$45.35***	300	350	***$0.0461***	***$4.84***	***$50.19***
400 W	Mercury Vapor	***$58.06***	450	350	***$0.0461***	***$7.26***	***$65.31***
1,000 W	Mercury Vapor	***$105.88***	1060	350	***$0.0461***	***$17.09***	***$122.97***
70 W	High Pressure Sodium	***$24.70***	95	350	***$0.0461***	***$1.53***	***$26.23***
100 W	High Pressure Sodium	***$27.96***	135	350	***$0.0461***	***$2.18***	***$30.14***
150 W	High Pressure Sodium	***$30.91***	200	350	***$0.0461***	***$3.22***	***$34.13***
250 W	High Pressure Sodium	***$38.67***	305	350	***$0.0461***	***$4.92***	***$43.59***
360 W	High Pressure Sodium	***$47.65***	418	350	***$0.0461***	***$6.74***	***$54.39***
400 W	High Pressure Sodium	***$49.85***	465	350	***$0.0461***	***$7.50***	***$57.35***
1,000 W	High Pressure Sodium	***$98.48***	1100	350	***$0.0461***	***$17.74***	***$116.22***

70 W	Metal Halide	***$34.28***	85	350	***$0.0461***	***$1.37***	***$35.65***
100 W	Metal Halide	***$36.27***	120	350	***$0.0461***	***$1.93***	***$38.21***
150 W	Metal Halide	***$42.34***	180	350	***$0.0461***	***$2.90***	***$45.24***
175 W	Metal Halide	***$40.37***	210	350	***$0.0461***	***$3.39***	***$43.76***
250 W	Metal Halide	***$47.93***	300	350	***$0.0461***	***$4.84***	***$52.76***

(Continued on Sheet No. D-51.01)

(Continued from Sheet No. D-51.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges (Contd):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
320 W	Metal Halide	***$54.26***	365	350	***$0.0461***	***$5.88***	***$60.15***
400 W	Metal Halide	***$62.50***	460	350	***$0.0461***	***$7.42***	***$69.92***
1,000 W	Metal Halide	***$105.01***	1050	350	***$0.0461***	***$16.93***	***$121.94***
20 - 29 W	***LED***	***$19.95***	25	350	***$0.0461***	***$0.40***	***$20.36***
30 - 39 W	LED	***$21.19***	35	350	***$0.0461***	***$0.56***	***$21.75***
40 - 49 W	LED	***$21.92***	45	350	***$0.0461***	***$0.73***	***$22.65***
50 - 59 W	LED	***$22.64***	55	350	***$0.0461***	***$0.89***	***$23.53***
60 - 69 W	LED	***$23.36***	65	350	***$0.0461***	***$1.05***	***$24.41***
70 - 79 W	LED	***$24.09***	75	350	***$0.0461***	***$1.21***	***$25.30***
80 - 89 W	LED	***$24.88***	85	350	***$0.0461***	***$1.37***	***$26.25***
90 - 99 W	LED	***$25.85***	95	350	***$0.0461***	***$1.53***	***$27.38***
100 - 109 W	LED	***$26.82***	105	350	***$0.0461***	***$1.69***	***$28.51***
110 - 119 W	LED	***$27.78***	115	350	***$0.0461***	***$1.85***	***$29.64***
120 - 129 W	LED	***$28.75***	125	350	***$0.0461***	***$2.02***	***$30.77***
130 - 139 W	LED	***$29.72***	135	350	***$0.0461***	***$2.18***	***$31.90***
140 - 149 W	LED	***$30.59***	145	350	***$0.0461***	***$2.34***	***$32.93***
150 - 159 W	LED	***$31.46***	155	350	***$0.0461***	***$2.50***	***$33.96***
160 - 169 W	LED	***$32.32***	165	350	***$0.0461***	***$2.66***	***$34.98***
170 - 179 W	LED	***$33.19***	175	350	***$0.0461***	***$2.82***	***$36.01***
180 - 189 W	LED	***$34.06***	185	350	***$0.0461***	***$2.98***	***$37.04***
190 - 199 W	LED	***$34.88***	195	350	***$0.0461***	***$3.14***	***$38.02***
200 - 209 W	LED	***$35.80***	205	350	***$0.0461***	***$3.31***	***$39.10***
210 - 219 W	LED	***$36.66***	215	350	***$0.0461***	***$3.47***	***$40.13***
220 - 229 W	LED	***$37.51***	225	350	***$0.0461***	***$3.63***	***$41.14***

(Continued on Sheet No. D-51.02)

(Continued from Sheet No. D-51.01)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges (Contd):

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
230 - 239 W	LED	***$38.40***	235	350	***$0.0461***	***$3.79***	***$42.19***
240 - 249 W	LED	***$39.27***	245	350	***$0.0461***	***$3.95***	***$43.22***
250 - 259 W	LED	***$40.14***	255	350	***$0.0461***	***$4.11***	***$44.25***
260 - 269 W	LED	***$41.00***	265	350	***$0.0461***	***$4.27***	***$45.28***
270 - 279 W	LED	***$41.90***	275	350	***$0.0461***	***$4.43***	***$46.33***
280 - 289 W	LED	***$42.74***	285	350	***$0.0461***	***$4.59***	***$47.34***
290 - 299 W	LED	***$43.61***	295	350	***$0.0461***	***$4.76***	***$48.36***
300 - 309 W	LED	***$44.53***	305	350	***$0.0461***	***$4.92***	***$49.45***
310 - 319 W	LED	***$45.41***	315	350	***$0.0461***	***$5.08***	***$50.49***
320 - 329 W	LED	***$46.29***	325	350	***$0.0461***	***$5.24***	***$51.53***
330 - 339 W	LED	***$47.16***	335	350	***$0.0461***	***$5.40***	***$52.56***
340 - 349 W	LED	***$48.04***	345	350	***$0.0461***	***$5.56***	***$53.60***
350 - 359 W	LED	***$48.92***	355	350	***$0.0461***	***$5.72***	***$54.64***
360 - 369 W	LED	***$49.80***	365	350	***$0.0461***	***$5.88***	***$55.68***
370 - 379 W	LED	***$50.67***	375	350	***$0.0461***	***$6.05***	***$56.72***
380 - 389 W	LED	***$51.55***	385	350	***$0.0461***	***$6.21***	***$57.76***
390 - 399 W	LED	***$52.43***	395	350	***$0.0461***	***$6.37***	***$58.80***

Long Span

- For lamp spacing over 120 feet up to 325 feet on the same side of street, add to rate per lamp per year.. $24.48

Semi-Ornamental

- For Semi-Ornamental Systems which employ Ornamental Post Units served from overhead conductors, where such construction is practical, reduce rate per luminaire per year $21.48

Post Charge

- For each increment of $1,000 of investment which exceeds three times the annual revenue at the prevailing rate at the time of installation, add to rate per year**……………………………………..*$84.96***

(Continued on Sheet No. D-52.00)

(Continued from Sheet No. D-51.02)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Multiple Luminaires on a Single Pole

- For additional luminaire*s* added to the same pole, a reduced rate per luminaire per year on the added luminaire***.***
  Ornamental $97.92
  Ornamental-Lamp spacing over 120 feet $122.40
  Semi-Ornamental $76.56

OPTION II: Street Equipment Owned by Municipality

MONTHLY RATES OPTION II: Overhead and Underground Ornamental Municipality Owned Street Lighting *(*All-night service*)*.

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge***: 4.61¢*** per kWh for all kWh

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
175 W	Mercury Vapor	***$10.11***	210	350	***$0.0461***	***$3.39***	***$13.50***
250 W	Mercury Vapor	***$14.45***	300	350	***$0.0461***	***$4.84***	***$19.29***
400 W	Mercury Vapor	***$21.67***	450	350	***$0.0461***	***$7.26***	***$28.93***
1,000 W	Mercury Vapor	***$51.06***	1060	350	***$0.0461***	***$17.09***	***$68.15***
70 W	High Pressure Sodium	***$5.84***	95	350	***$0.0461***	***$1.53***	***$7.37***
100 W	High Pressure Sodium	***$7.63***	135	350	***$0.0461***	***$2.18***	***$9.80***
250 W	High Pressure Sodium	***$15.21***	305	350	***$0.0461***	***$4.92***	***$20.13***
360 W	High Pressure Sodium	***$20.25***	418	350	***$0.0461***	***$6.74***	***$26.99***
400 W	High Pressure Sodium	***$22.34***	465	350	***$0.0461***	***$7.50***	***$29.84***
1,000 W	High Pressure Sodium	***$50.66***	1100	350	***$0.0461***	***$17.74***	***$68.40***

- The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, customers will be given the option of switching to High Pressure Sodium, Metal Halide, LED or retiring the Luminaire.

(Continued on Sheet No. D-53.00)

(Continued from Sheet No. D-52.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

- **DE-ENERGIZED LIGHTS:** Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 10% of the above yearly rates. A $35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.
- **DUSK TO MIDNIGHT SERVICE:** For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a discount of 1.060¢ per nominal watt per month will be applied. One control per circuit will be provided.

OPTION III: Municipally Owned and Maintained Street Lighting System (Unmetered)

HOURS OF SERVICE: For circuits controlled by automatic timing devices, one-half hour after sunset until one-half hour before sunrise. For circuits controlled by photo-sensitive devices, dusk to dawn for approximately 4,200 hours per year.

RATES: Where the municipality owns, operates, cleans and renews the lamps, and the Company's service is confined solely to the supply of electricity from dusk to dawn, the monthly charge of said service shall be a power supply capacity energy charge of 0.00¢ per kilowatthour, a power supply non-capacity charge of ***4.61¢*** per kilowatthour and a distribution charge of ***12.81¢*** per kilowatthour. If it is necessary for the Company to install facilities to provide service for the lamps, the customer will reimburse the Company for these costs. Contract Rider No. 2 charges will also apply.

OPTION III: Municipally Owned and Maintained Street Lighting System (Controlled/Metered)

AVAILABILITY OF SERVICE: Available to governmental agencies desiring controlled nighttime service for primary or secondary voltage energy-only street lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires served under any of the Company's other street lighting rates shall not be intermixed with luminaires serviced under this street lighting rate. This rate is not available for resale purposes. Service is governed by the Company's Standard Rules and Regulations.

KIND OF SERVICE:
Secondary Voltage Service: Alternating current, 60 hertz, single-phase 120/240 nominal volt service for a minimum of ten luminaires located within a clearly defined area. Except for control equipment, the customer will furnish, install, own and maintain all equipment comprising the street lighting system up to the point of attachment with the Company's distribution system. The Company will connect the customer's equipment to the Company's lines and supply the energy for operation. All of the customer's equipment will be subject to the Company's review.

Primary Voltage Service: Alternating current, 60 hertz, single-phase or three-phase, primary voltage service for actual demands of not less than 100 kW at each point of delivery. The particular nature of the voltage shall be determined by the Company. The customer will furnish, install, own and maintain all equipment comprising the street lighting system, including control equipment, up to the point of attachment with the Company's distribution system. The Company will supply the energy for operation of the customer's street lighting system.

(Continued on Sheet No. D-54.00)

(Continued from Sheet No. D-53.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Primary and Secondary Energy
Full Service Customers:

Power Supply Charge:

Capacity Dusk to Midnight: ***8.305¢*** per kWh
Capacity Energy Charge: ***1.901¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***3.730¢*** per kWh for all kWh

Delivery System Charge:

5.288¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge*:* ***1.901¢*** per kWh for all kWh

Delivery System Charge:

5.858¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption and the total annual kWh consumption.

At the Company's option, service may be metered and the metered kWh will be the basis for billing. Capacity requirements of lighting equipment shall be determined by the Company from manufacturer specifications, but the Company maintains the right to test such capacity requirements from time to time. In the event that Company tests show capacity requirements other than those indicated in manufacturer specifications, the capacity requirements indicated by Company tests will be used. The customer shall not change the capacity requirements of its equipment without first notifying the Company in writing.

BILLING: Billing will be on a monthly basis.

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The contract minimum.

CONTRACT TERM: Contracts will be taken for a minimum of two years, extending thereafter from year to year until terminated by mutual consent or upon 12 months' written notice by either party.

RATE SCHEDULE NO. E2 **TRAFFIC AND SIGNAL LIGHTS**

AVAILABILITY OF SERVICE: Available to municipalities or other public authorities, hereinafter referred to as customer, operating lights for traffic regulation or signal lights on streets, highways, airports or water routes, as distinguished from street lighting. Customers desiring service under Rate Schedule No. E2 are free to determine the appropriate light source for their application including incumbent and emerging technologies (including LEDs). Customers must supply adequate documentation of the wattage of the light source that will be subject to the approval of the Company.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, at 120 volts two-wire.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, including lamps and lamp replacements, or reimburse the Company therefore, except that the Company will furnish, install and maintain such span poles and messenger cable as may be needed to support the traffic or signal lights of the overhead type. Connections are to be brought to the Company's underground and overhead lighting mains by the customer as directed by the Company, and the final connection to the Company's main is to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATES: Distribution charge of ***2.91¢***, capacity energy charge of ***1.53¢*** and non-capacity energy charge of ***4.92¢*** per month per kilowatthour of the total connected traffic light or signal light load in service for each customer.

Total connected wattage will be reckoned as of the fifteenth of the month. Lamps removed from service before the fifteenth or placed in service on or after the fifteenth will be omitted from the reckoning; conversely, lamps placed in service on or before the fifteenth of the month or removed from service after the fifteenth of the month will be reckoned for a full month. Lamps operated cyclically, on and off, will be reckoned at one-half wattage and billed for a full month. No such reduction of reckoned wattage will be allowed for lamps in service but turned off during certain hours of the day.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

SURCHARGES AND CREDITS: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: $3.00 per customer per month.

CONTRACT TERM: Open order on a month-to-month basis. However, the Company shall not withdraw service, and the customer shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

STANDARD CONTRACT RIDER NO. 1.1 ALTERNATIVE ELECTRIC METAL MELTING

APPLICABLE TO:

General Service Rate	Schedule Designation D3
Large General Service Rate	Schedule Designation D4
Interruptible Supply Rate	Schedule Designation D8
Primary Supply Rate	Schedule Designation D11

Customers operating electric furnaces for metal melting or for the reduction of metallic ores and/or electric use consumed in holding operations and taking their supply at any of the above rates and who provide special circuits so that the Company may install necessary meters, may take service under this interruptible service Rider subject to Section C4.4 - Choice of Rates. ***Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.***

HOURS OF INTERRUPTION: All interruptible load served hereunder shall be subject to interruption by the Company in order to maintain system integrity. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3.

TESTING PROCEDURES: In accordance with participation in an interruptible tariff, the customer agrees to comply with Company requirements regarding testing procedures. Customer shall complete and sign an interruptible responsibility letter annually by April 1st. Failure to sign and submit the interruptible responsibility letter may result in removal from this interruptible tariff. The letter designates that the customer understands their responsibility to interrupt, has an interruption plan, and has the capability to interrupt the contracted load. In addition, the Company will conduct multiple simulations each year to verify the communication system is working properly.

NOTICE OF INTERRUPTION: The customer shall be provided, whenever possible; 1) notice in advance (generally 1 hour) of probable interruption***;*** 2) the time in which customer must fully reduce load, and; 3) the estimated duration of the interruption. The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of Interruption shall be billed at the rate the higher of (i) the rate of $50 per kW applied to the highest 60-minute integrated interruptible demand (kW) created during the interruption period or (ii) the actual damages incurred by the Company, including any MISO penalties, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with an interruption order may be immediately reduced by the amount the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

Electric energy from any facilities, other than the Company's, except for on-site generation installed prior to January 1, 1986, will be used to first reduce the sales on this rider. Standby service will not be billed at this rider, but must be taken under Riders No. 3, No. 5 or No. 6.

(Continued on Sheet No. D-58.00)

(Continued from Sheet No. D-57.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.) **ALTERNATIVE ELECTRIC METAL MELTING**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)
1.897¢ per kWh for the first 100 hours use of maximum demand
0.718¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.411¢ per kWh for the first 100 hours use of maximum demand
0.513¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.376¢ per kWh for the first 100 hours use of maximum demand
0.478¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.166¢ per kWh for the first 100 hours use of maximum demand
0.387¢ per kWh for the excess

Non-Capacity

Energy Charge***:*** ***4.720¢*** per kWh for all kWh

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)
5.858¢ per kWh for the first 100 hours use of maximum demand
5.858¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.912¢ per kWh for the first 100 hours use of maximum demand
1.912¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.507¢ per kWh for the first 100 hours use of maximum demand
0.507¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.566¢ per kWh for the first 100 hours use of maximum demand
0.566¢ per kWh for the excess

(Continued on Sheet No. D-59.00)

(Continued from Sheet No. D-58.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.) **ALTERNATIVE ELECTRIC METAL MELTING**

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

Retail Access Service Customers:

Capacity (Only applicable to Retail access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charges:
For service at secondary voltage level (less than 4.8 kV)
1.897¢ per kWh for the first 100 hours use of maximum demand
0.718¢ per kWh for the excess

For service a primary voltage level (4.8 kV to 13.2 kV)
1.411¢ per kWh for the first 100 hours use of maximum demand
0.513¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.376¢ per kWh for the first 100 hours use of maximum demand
0.478¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.166¢ per kWh for the first 100 hours use of maximum demand
0.387¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:
Distribution Charges:
For service at secondary voltage level (less than 4.8 kV)
5.858¢ per kWh for the first 100 hours use of maximum demand
5.858¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.912¢ per kWh for the first 100 hours use of maximum demand
1.912¢ per kWh for the excess

(Continued from Sheet No. D-60.00)

(Continued from Sheet No. D-59.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.) **ALTERNATIVE ELECTRIC METAL MELTING**

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.507¢ per kWh for the first 100 hours use of maximum demand
0.507¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.566¢ per kWh for the first 100 hours use of maximum demand
0.566¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute integrated demand created during the current billing month. This clause is applicable to each voltage level served.

MINIMUM CHARGES: 1) A monthly minimum charge of $2.10 per kW of contract capacity shall be applied to that portion of the customer's load which is served under this rider. This minimum charge will be waived if the customer over the past 12 months (including the current bill), or from the start of the contract term if less than 12 months, has averaged $2.10 per kW per month in revenues. This minimum charge is in addition to the minimum charge under the above rates, plus; 2) any applicable per meter per month surcharges.

POWER FACTOR CLAUSE (Retail Access Service Customers Only): A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location’s single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of $3.50/kVAR will be applied to excess Reactive Demand.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the normal maximum requirements of the load qualifying for service under this rider. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for this rider shall not be included in the contract capacity established for the filed rate which is used in conjunction with this rider.

SPECIAL TERMS AND CONDITIONS: The customer is responsible for all new facilities and lines required for service under this rider. Said facilities and lines must meet all Company standards. The Company at its option may install and own said facilities under the provisions of Standard Contract Rider No. 2.

TERM: One year under written contract and month-to-month thereafter.

STANDARD CONTRACT RIDER NO. 1.2 **ELECTRIC PROCESS HEAT**

APPLICABLE TO:		
	General Service Rate	Schedule Designation D3
	Large General Service Rate	Schedule Designation D4
	Interruptible Supply Rate	Schedule Designation D8
	Primary Supply Rate	Schedule Designation D11

Customers using electric heat as an integral part of a manufacturing process, or electricity as an integral part of an anodizing, plating or coating process, and taking their supply at any of the above rates and who provide special circuits to accommodate separate metering may take service under this interruptible service Rider subject to Section C4.4- Choice of Rates.

This Rider is available only to customers who add new load on or after May 1, 1986 to engage in the above described processes and to customers served on R1.1 prior to May 1, 1986 and engaged in the above described processes. ***Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.***

HOURS OF INTERRUPTION: All interruptible load served hereunder shall be subject to interruption by the Company in order to maintain system integrity. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3.

TESTING PROCEDURES: In accordance with participation in an interruptible tariff, the customer agrees to comply with Company requirements regarding testing procedures. Customer shall complete and sign an interruptible responsibility letter annually by April 1st. Failure to sign and submit the interruptible responsibility letter may result in removal from this interruptible tariff. The letter designates that the customer understands their responsibility to interrupt, has an interruption plan, and has the capability to interrupt the contracted load. In addition, the Company will conduct multiple simulations each year to verify the communication system is working properly.

NOTICE OF INTERRUPTION: The customer shall be provided, whenever possible***;*** 1) notice in advance (generally 1 hour) of probable interruption; 2) the time in which customer must fully reduce load, and; 3) the estimated duration of the interruption. The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of Interruption shall be billed at the higher of (i) the rate of $50 per kW applied to the highest 60-minute integrated interruptible demand (kW) created during the interruption period or (ii) the actual damages incurred by the Company, including any MISO penalties, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with an interruption order may be immediately reduced by the amount the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

Electric energy from any facilities, other than the Company's, except for on-site generation installed prior to January 1, 1986, will be used to first reduce the sales on this rider. Standby service will not be billed at this rider, but must be taken under Riders No. 3, No. 5 or No. 6.

(Continued on Sheet No. D-62.00)

(Continued from Sheet No. D-61.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.) **ELECTRIC PROCESS HEAT**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)
1.897¢ per kWh for the first 100 hours use of maximum demand
0.718¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.411¢ per kWh for the first 100 hours use of maximum demand
0.513¢ per kWh for the excess

For service at primary voltage level (24 kV to 41.6 kV)
1.376¢ per kWh for the first 100 hours use of maximum demand
0.478¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.166¢ per kWh for the first 100 hours use of maximum demand
0.387¢ per kWh for the excess

Non-Capacity

Energy Charge: ***4.720¢*** per kWh for all kWh

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)
5.858¢ per kWh for the first 100 hours use of maximum demand
5.858¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.912¢ per kWh for the first 100 hours use of maximum demand
1.912¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.507¢ per kWh for the first 100 hours use of maximum demand
0.507¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.566¢ per kWh for the first 100 hours use of maximum demand
0.566¢ per kWh for the excess

(Continued on Sheet No. D-63.00)

(Continued from Sheet No. D-62.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.) **ELECTRIC PROCESS HEAT**

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)
1.897¢ per kWh for the first 100 hours use of maximum demand
0.718¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.411¢ per kWh for the first 100 hours use of maximum demand
0.513¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.376¢ per kWh for the first 100 hours use of maximum demand
0.478¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.166¢ per kWh for the first 100 hours use of maximum demand
0.387¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:
Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)
5.858¢ per kWh for the first 100 hours use of maximum demand
5.858¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.912¢ per kWh for the first 100 hours use of maximum demand
1.912¢ per kWh for the excess

(Continued on Sheet No. D-64.00)

(Continued from Sheet No. D-63.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.) **ELECTRIC PROCESS HEAT**

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.507¢ per kWh for the first 100 hours use of maximum demand
0.507¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.566¢ per kWh for the first 100 hours use of maximum demand
0.566¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MAXIMUM DEMANDS: The maximum demand shall be the highest 30-minute integrated demand created during the current billing month. This clause is applicable to each voltage level served.

MINIMUM CHARGES: 1) A monthly minimum charge of $2.10 per kW of contract capacity shall be applied to that portion of the customer's load which is served under this rider. This minimum charge will be waived if the customer over the past 12 months (including the current bill), or from the start of the contract term if less than 12 months, has averaged $2.10 per kW per month in revenues. This minimum charge is in addition to the minimum charge under the above rates, plus; 2) any applicable per meter per month surcharges.

POWER FACTOR CLAUSE (Retail Access Service Customers Only): A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location’s single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of $3.50/kVAR will be applied to excess Reactive Demand.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the normal maximum requirements of the load qualifying for service under this rider. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for this rider shall not be included in the contract capacity established for the filed rate which is used in conjunction with this rider.

SPECIAL TERMS AND CONDITIONS: The customer is responsible for all new facilities and lines required for service under this rider. Said facilities and lines must meet all Company standards. The Company at its option may install and own said facilities under the provisions of Standard Contract Rider No. 2.

TERM: One year under written contract and month-to-month thereafter.

STANDARD CONTRACT RIDER NO. 3 PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

This rider provides the terms and conditions of standby and supplemental service to customers operating on-site generation. The rate distinguishes the form of service provided as either standby service or supplemental service. Standby service is generally defined as capacity and energy service provided by the Company to serve customer load that is normally served by the customer's generator. Supplemental service is generally defined as capacity and energy service provided by the Company to serve customer load above their standby service requirements. The point of separation between standby and supplemental service is based on the customer's standby contract capacity for the facility, measured in kW. Any service provided by the Company up to and including the standby contract capacity level is standby service, and any service provided above the standby contract capacity level is supplemental service. Modeling standby and supplemental rate impacts is depend*e*nt on several factors including customer load profile and type of generator(s) and other considerations. The Company provides rate impact studies for customers considering on-site generation in addition to online resources and answers to frequently asked questions.

There are two categories of standby service provided under this rider ***for customers operating on site generation***, "STANDBY SERVICE" AND "STATION POWER STANDBY SERVICE". STANDBY SERVICE applies to customers with generation facilities that are located within the Company's retail service territory and directly interconnected with the Company. STATION POWER STANDBY SERVICE applies to customers with generation facilities that are located within the Company's retail service territory and that are directly interconnected to ITC Transmission. For customers exporting power from their facility, the customer's generation must, at all times, first serve their standby load requirements contracted under this tariff.

STANDBY SERVICE

STANDBY SERVICE: Available to customers with generation facilities that are located within the Company's retail service territory and directly interconnected with the Company. Customers who desire the Company to serve the power supply requirements of load that ***is*** normally served by the customer's generator or prime mover must take standby service under the provisions of this rider unless otherwise exempted by order of the Michigan Public Service Commission or by the provisions set forth below and must take supplemental service on one of the applicable filed rates listed below.

Customers purchasing their entire energy requirements from the Company with generators or prime movers installed for use only in emergency will not be considered as taking standby service.

Customers with generators or prime movers installed solely for use to provide a load for testing equipment such as regenerative dynamometers may elect not to purchase standby energy service for that equipment under this rider, must meet the applicable parallel operation requirement, must purchase power that would, absent this provision, be considered standby on another rate schedule and must take standby for any additional generating equipment normally serving site load.

Customers with solar self-generating projects and taking service under a tariff with demand based distribution charges may elect not to purchase standby energy service for that equipment under this rider, must meet the applicable parallel operation requirements, must purchase power that would, absent this provision, be considered standby on another rate schedule and must take standby for any additional generating equipment normally serving site load.

(Continued on Sheet No. D-68.00)

(Continued from Sheet No. D-70.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

DEFINITIONS (contd):

MAINTENANCE PERIODS (contd):

(e) If there is a substantial change in circumstances which make the agreed upon schedule impractical for either party, the other party upon request shall make reasonable efforts to adjust the schedule in a manner that is mutually agreeable.

WAIVERS AND LIMITS FOR GENERATION RESERVATION FEE AND DAILY DEMAND CHARGES:

For customers taking supplemental service on rate schedules D4, D11, D6.2 or D8, the following waivers apply:

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the generation reservation fee will be waived for that month.

Waivers and limits for energy-only rates:

For customers taking supplemental service on energy-only rates for the entire billing cycle, schedules D3, or D3.3, the following applies.

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the daily demand charges will be waived for that month provided that the supplemental rate continues as an energy-only rate. If not, then the total of daily demand charges for the month will be charged and the generation reservation fee for the month will be waived.

RATES:

Power Supply Charges:

Capacity

Monthly Generation Reservation Fee:

$***0.35*** times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is $***0.97*** per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is $***0.49*** per kW per day during maintenance periods as defined below.

(Continued from Sheet No. D-72.00)

(Continued from Sheet No. D-72.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

RATES (contd):

Energy Charge:

For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Non-Capacity

Monthly Generation Reservation Fee:

$***0.26*** times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is $***0.72*** per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is $***0.36*** per kW per day during maintenance periods as defined below.

Energy Charge:

An energy charge for back-up and maintenance power will be charged based on standby contract capacity less the output toward internal load of the customer's generator, but not less than zero. For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be ***4.903¢*** per kWh, plus appropriate power supply credits, including but not limited to an off-peak credit of 1.00¢ per kWh, and voltage level credits of 0.062¢ per kWh for subtransmission and ***0.139¢*** per kWh for transmission. For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge:

$70 per customer per month for customers served at primary voltage.
$375 per customer per month for customers served above primary voltage.
$70 per customer per month for customers served at secondary voltages.

Distribution Charge:

Distribution charges will be as follows:

$***6.32*** per kW at primary voltage applied to the standby contract capacity
$***1.73*** per kW at subtransmission voltage applied to the standby contract capacity
$***0.93*** per kW at transmission voltage applied to the standby contract capacity

(Continued on Sheet No. D-73.00)

(Continued from Sheet No. D-72.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

RATES (contd):

Distribution Charge:

For service provided in conjunction with a secondary voltage base rate the Delivery Charge will be the greater of $***14.65*** per kW applied to standby contract capacity or ***5.858*** ¢/kWh applied to all standby energy delivered.

Substation Credit: Available to customers served at subtransmission voltage level (24 to 41.6 kW) or higher who provide the on-site substation including all necessary transforming, controlling, and protective equipment. A credit of $.30 per kW shall be applied to the distribution demand charge per kW of standby capacity. An additional credit of 0.040¢ per kWh of standby delivered will be given where the service is metered on the high voltage side of the transformer.

Surcharges and Credits Applicable to Delivery Service: As approved by the Commission. See Section C9.8.

ADJUSTMENT OF PRIOR RATCHETS: When a customer takes standby service under Rider No. 3, the setting or the increasing or decreasing of standby contract capacity will affect the existing ratchet levels on the supplemental rate as follows:

(a) An amount in kW equal to the initial standby contract capacity (or to the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted maximum demand level for customers on supplemental rates D6.2 and D8 and D11.

(b) An amount in kW equal to 65% of the initial standby contract capacity (or of the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted on-peak billing demand level for customers on supplemental rates D4, D6.2 and D8 and D11.

LATE PAYMENT CHARGE: See Section C4.8.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Customers are responsible for correcting power factors less than 70% at their own expense. The size, type and location of any power factor correction equipment must be approved by the Company. Such approval will not be unreasonably withheld. A penalty will be applied to the total amount of the monthly billing for supplemental and standby service for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The penalty will not be applied to the on-peak billing demand ratchet nor to the minimum contract demand of the supplemental rate, but will be applied to metered quantities.

(Continued on Sheet No. D-73.01)

(Continued from Sheet No. D-73.01)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

STATION POWER STANDBY SERVICE

SERVICE UNDER THIS PROVISION BECOMES EFFECTIVE APRIL 1, 2014

STATION POWER STANDBY SERVICE: Available to customers with generation facilities that are located within the Company's retail service territory and that are interconnected to ITC Transmission. The power supply requirements necessary to maintain and operate the generating facility that are normally served by the facility's on-site generation but which instead are provided by the facility's taking power through its transmission interconnection must be provided under the station Power Standby Service provisions of this rider.

APPLICABLE TO: General Service Rate Schedule Designation D3

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CONTRACT CAPACITY: Customers shall initially contract for a specified capacity in kilowatts sufficient to meet expected maximum requirements. Any single reading of the demand meter or aggregation of demand meters recording inflow to the facility in any month that exceeds the contract capacity then in effect shall become the new contract capacity.

METERING REQUIREMENTS: All customers taking service under this rider must install the necessary equipment to permit metering. The Company will supply the metering equipment. Service to the customer under this Rider will be metered with demand-recording equipment. Any equipment installed by the customer necessary to accommodate the Company's metering equipment must be approved by the Company and must be compatible with the Company's Meter Data Acquisition System.

RATES:

Power Supply:

Non-Capacity

Station Power Energy Service will be priced on the basis of the real time MISO locational hourly marginal energy price for the Company-appropriate load node. In additional to the MISO locational hourly marginal energy price the following charges will also apply:

0.769¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of 0.000¢/kWh plus,
Surcharges and Credits Applicable to Power Supply, excluding PSCR, as approved by the Commission. See Section C8.5

Service Charge:

Primary Service Charge:	$70 per month
Subtransmission and Transmission Service Charge:	$375 per month

(Continued on Sheet No. D-73.03)

STANDARD CONTRACT RIDER NO. 7 **GREENHOUSE LIGHTING SERVICE**

APPLICABLE TO:	General Service Rate	Schedule Designation D3
	Large General Service Rate	Schedule Designation D4

Available on an optional basis to customers desiring high intensity discharge lighting service for greenhouses or other environmentally controlled growing facilities as a daylight supplement. All lighting on this rider shall be separately metered. The customer will furnish, install, own, and maintain all equipment comprising the lighting system. No other device may be connected to this circuit except for controls, lighting and associated equipment.

HOURS OF SERVICE: Dusk to dawn service for circuits controlled by photo-sensitive or clock timing devices.

CURRENT, PHASE AND VOLTAGE: Alternating current, 60 hertz, single phase, nominally at 120/240 volts, three-wire; or three-phase, four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase, four-wire, Y connected at 480Y/277 volts.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:
Capacity Energy Charge: ***1.578¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***3.092¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service for DTE:
Capacity Energy Charge: ***1.578¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-85.00)

STANDARD CONTRACT RIDER NO. 8 **COMMERCIAL SPACE HEATING**

APPLICABLE TO:	General Service Rate	Schedule Designation D3
	Large General Service Rate	Schedule Designation D4

Available on an optional basis to customers desiring service for commercial space conditioning furnished through separately metered circuits to which no other device except electric space heating, water heating, air conditioning, or humidity control equipment may be connected and provided that all of the space heating must be either total electric or an electric heat pump supplemented by a fossil fuel furnace installed on a permanent basis. The customer must provide special circuits, the design and method of installation of which are approved by the Company as adapted to this service.

Electric space heating under the terms of this rider will be considered to include heating by light systems, provided the primary means of space heating at the time of maximum requirements will be furnished by the lighting system, with the balance furnished by supplementary electric heating equipment. After June 15, 1970, under the authority of the Commission in Case U-3189, service to facilities which heat by lighting is not available for premises not previously qualified for service hereunder.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:

Capacity Energy Charge:	***4.257¢*** per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ***1.411¢*** per kWh.
Non-Capacity Energy Charge:	***4.702¢*** per kWh

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity service from DTE***:***

Capacity Energy Charge:	***4.257¢*** per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ***1.411¢*** per kWh.

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***5.858¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-87.00)

(Continued from Sheet No. D-86.00)

STANDARD CONTRACT RIDER NO. 8 (Contd.) **COMMERCIAL SPACE HEATING**

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: This rate is made effective by a rider modifying the contract form prescribed for one of the applicable filed rates listed above. The contract term is co-extensive with the contract term of the applicable filed rate under which service is being taken.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

OPTIONAL PROVISION FOR CERTAIN COMMON AREA ACCOUNTS: Electric heating and common area usage of apartment or condominium accounts supplied through a single meter and billed under the terms of the Domestic Space Heating Rate D2 prior to September 28, 1978 may be billed under this provision without the necessity of separate metering if an initial block of kilowatthours is billed at the current General Service Rate D3. This initial block of kilowatthours will be calculated each November by averaging the usage during the previous billing months of June through October.

Full Service Customers:

Usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ***4.257¢*** and a non-capacity charge of ***4.702¢*** per kilowatthour during the billing months of June through October, and a capacity charge of ***1.411¢*** and a non-capacity charge of ***4.702¢*** per kilowatthour during the billing months of November through May. A Distribution charge of ***5.858¢*** per kWh for all kWh shall also be applied. The only service charge to be billed to a customer utilizing this provision will be the D3 service charge.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service from DTE:

For Retail Access customers taking capacity service from DTE, usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ***4.257¢*** per kilowatthour during the billing months of June through October, and a power supply capacity charge of ***1.411¢*** per kilowatthour during the billing months of November through May.

For all retail access customers, usage in excess of the initial block of kilowatthours per month shall be billed a distribution charge of ***5.858¢*** per kWh for all kWh.

SUPPLEMENTAL SPACE HEATING PROVISION: This provision is available to customers taking service under the General Service Rate D3 or the Large General Service Rate D4 who purchase energy for a minimum of 10 kW of supplemental, permanently installed, electric space heating equipment. To qualify for this provision, a customer must certify in writing the amount of permanently installed space heating equipment, subject to inspection at the option of the Company, and have the said equipment on separately metered circuits to which no other device is connected. Section C4.9, Insulation Standards for Electric Heating, will not apply to this provision.

(Continued from Sheet No. D-90.00)

STANDARD CONTRACT RIDER NO. 10 (Contd.) **INTERRUPTIBLE SUPPLY RIDER**

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. Demand/Energy in excess of the contracted load level will be billed under the applicable Primary Supply Rate. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a specific reduction in connected load. Capacity disconnected from service under this rider shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Non-Capacity**:**
The Energy charge will be the real time MISO locational hourly marginal energy price for the DTE Electric-appropriate load node. In addition to the MISO locational hourly marginal energy price the following charges will also apply:

0.769¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of 0.000¢/kWh plus,
A voltage level service adder of 1.56% for transmission, 3.73% for subtransmission and 5.50% for primary.

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24kV) $***6.32*** per kW of maximum demand
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

(Continued on Sheet No. D-92.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Ninth Revised Sheet No. D-92.00
Cancels Eighth Revised Sheet No. D-92.00

(Continued from Sheet No. D-91.00)

STANDARD CONTRACT RIDER NO. 10 (Contd.) **INTERRUPTIBLE SUPPLY RIDER**

Retail Access Service Customers:

Delivery Charges:
Primary Service Charge: $70 per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24kV) $***6.32*** per kW of maximum demand
For service at subtransmission voltage (24 to 41.6 kV) $***1.73*** per kW of maximum demand
For service at transmission voltage (120 kV and above) $***0.93*** per kW of maximum demand.

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus the Maximum Demand Charge, plus all applicable energy charges plus any applicable per meter per month surcharge.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of the contract capacity. This clause is applicable to each voltage level served.

POWER FACTOR CLAUSE: Shall be the Power Factor Clause as defined in the Primary Supply Rate (D11).

SPECIAL TERMS AND CONDITIONS: Customer-owned equipment must be operated so the voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.

The customer will own and maintain the necessary equipment to separate the interruptible load from the firm power load. This equipment must meet the Company standards. The customer must also provide space for the separate metering of the interruptible load.

The interruptible load shall not be served from firm power circuits at any time. Violations of this provision will result in a charge of $50 per kilowatt per month applied to the interruptible load determined to have been served from firm power circuits.

(Continued on Sheet No. D-93.00)

Issued _______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after _________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ____________________, 2025
in Case No. U-21534

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-21534)

Fourth Revised Sheet No. D-115.00
Cancels Third Revised Sheet No. D-115.00

(Continued from Sheet D-114.00)

STANDARD CONTRACT RIDER NO. 18 (contd.) **DISTRIBUTED GENERATION PROGRAM**

Rate Schedule	Outflow Credit $ per kWh			
Residential				
D1/D1.6 Residential	First 17 kWh per Day: $*0.08765*	Excess: $*0.10139*		
D1.1 Int. Air	Summer: $*0.07384*	Winter: $*0.05151*		
D1.2 Time-of-Day	Summer On-Peak: $*0.15890*	Summer Off-Peak: $*0.05350*	Winter On-Peak: $*0.13422*	Winter Off-Peak: $*0.05140*
D1.7 Time-of-Day	Summer On-Peak: $*0.13836*	Summer Off-Peak: $*0.04583*	Winter On-Peak: $*0.05978*	Winter Off-Peak: $*0.04698*
D1.8 Dymanic Peak Pricing	Critical Peak: $0.95000	On-Peak: $*0.17222*	Mid-Peak: $*0.08896*	Off-Peak: *$0.4590*
D1.9 Elec. Vehicle	On-Peak: $*0.17383*	Off-Peak: $*0.04346*		
D1.11 Stan. TOU	June-Sept On-Peak: *$0.14487*	June-Sept Off-Peak: $**0.08728**	Oct-May On-Peak: $*0.10217*	Oct-May Off-Peak: $*0.08728*
D1.13 Overnight Savers	On-Peak: June-Sept: $*0.16118* Oct-Nov: $*0.09194*	Off-Peak: June-Sept: $*0.10846* Oct-Nov: $*0.08252*	Super Off-Peak: June-Sept: $*0.06850* Oct-Nov: $*0.06850*	
D2 Elec Space Heat	Summer First 17 kWh per Day: $*0.08152*	Summer Excess: $*0.09436*	Winter First 20 kWh per Day: $*0.06925*	Winter Excess: $*0.05852*
D5 Water Heat	All kWh: $*0.04909*			
Secondary				
D1.1 Int. Air	Summer: $*0.07512*	Winter: $*0.05923*		
D1.7 Time-of-Day	Summer On-Peak: $*0.04995*	Summer Off-Peak: $*0.04562*	Winter On-Peak: $*0.04670*	Winter Off-Peak: $*0.04670*
D1.8 Dynamic Peak Pricing	Critical Peak: $0.95	On-Peak: $*0.16810*	Mid-Peak: $*0.09035*	Off-Peak: $*0.04599*
D1.9 Elec. Vehicle	On-Peak: $*0.17383*	Off-Peak: $*0.04346*		
D3 General Service	All kWh: $*0.08176*			
D3.2 Secondary Education	All kWh: $*0.07908*			
D3.3 Interruptible General Service	All kWh: $*0.06832*			
D3.11 TOU General Service	***June-Sept On-Peak: $0.12863***	***June-Sept Off-Peak: $0.07672***	***Oct-May On-Peak: $0.08209***	***Oct-May Off-Peak: $0.07672***
D4 Large General Service	Demand: $*16.66*	First 200 kWh per kW: $*0.04030*	Excess: $*0.03111*	
D5 Water Heat	All kWh: $*0.04814*			
E1.1 Eng. St. Ltg.	All kWh: $*0.05631*			

(Continued on Sheet No. D-116.00)

Issued ______________, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after _________________, 2025

Issued under authority of the
Michigan Public Service Commission
dated ___________________, 2025
in Case No. U-21534

(Continued from Sheet D-115.00)

STANDARD CONTRACT RIDER NO. 18 (contd.) **DISTRIBUTED GENERATION PROGRAM**

Rate Schedule	Outflow Credit $ per kWh			
Primary				
D11 Primary Supply	Demand:	On-Peak:	Off-Peak:	
Primary	$*16.99* per kW	$*0.04275*	$*0.03275*	
Subtransmission	$*16.64* per kW	*$0.04213*	$*0.03213*	
Transmission	$*16.27* per kW	$.*0.04136*	$*0.03136*	
D6.2 Primary Educational Institution	Demand:	On-Peak:	Off-Peak:	
Primary	$*14.78* per kW	$*0.04669*	$*0.04369*	
Subtransmission	$*14.48* per kW	$*0.04590*	$*0.04290*	
Transmission	$*14.16* per kW	$*0.04494*	$*0.04194*	
D8 Interruptible Supply	Demand:	On-Peak	Off-Peak	
Primary	$*10.12* per kW	$*0.04275*	$*0.03275*	
Subtransmission	$*9.92* per kW	$*0.04213*	$*0.03213*	
Transmission	$*9.69* per kW	$*0.04136*	$*0.03136*	
D10 All Electric School	Summer: $*0.09579*	Winter: *$0.07566*		
D13 XL	All kWh: $*0.05109*			
D14 TOU Primary	***June-Sept On-Peak:***	***June-Sept Off-Peak:***	***Oct-May On-Peak:***	***Oct-May Off-Peak:***
Primary	***$0.10343***	***$0.06155***	***$0.07149***	***$0.06155***
Subtransmission	***$0.10225***	***$0.06037***	***$0.07031***	***$0.06037***
Transmission	***$0.10079***	***$0.05891***	***$0.06885***	***$0.05891***

(1) Retail Open Access Customers
The Outflow Credit will be determined by the Retail Service Supplier. For customers taking capacity service from the Company, the capacity outflow credit shall be the appropriate capacity rate(s) from the customer's rate schedule.

APPLICATION FOR SERVICE

In order to participate in the Distributed Generation Program, a customer shall submit completed Interconnection and Distributed Generation Program Applications, including the application fee of $50 to the Company.

The Distributed Generation Program application fee is waived if the customer is transitioning from the Net Metering Program.

If a customer does not act or correspond on an application for over 6 months, when some action is required by the customer, the application may be voided by the Company.

(Continued on Sheet No. D-116.01)

DTE Electric Company
Capacity Charge Revenue Requirement by Customer Class /
SRM Capacity Charge
(thousands of dollars)
FOR ORDER

		Total Electric
	CAPACITY COSTS DETERMINATION	
1	Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 29)	$ 3,101,057
2	Less Fuel (Exh A-16 Sch F1.1 Line 6)	(914,888)
3	Less MERC Rev Req (Exh A-16, Sch F1.5 Page 6 Line 9)	(6,399)
4	Less MISO Energy in PP (Exh A-13 Sch C4 Lines 21-22)	(40,376)
5	Less Other Energy in PP (WP A16 F1 Sch 11.5 Line 14)	(260,787)
6	Less Variable O&M (Exh A-16 Sch F1.5 Page 5 Line 8)	(30,392)
7	Subtotal	$ 1,848,215
8		
9	Proj 2025 Energy Sales Rev Net of Fuel (per A-26, Sch P3, Line 23)	(815,274)
10		
11	Capacity Revenue Requirement (Line 6 + Line 7)	$ 1,032,942
12		
13	SRM Capacity Charge Demand (DTE 2022 10-k, pg 9 / net gen capacity 11,717 MW + long-term contracts 560 MW)	12,277 MW
14		
15	SRM Capacity Charge per MW-Year (Line 11 / Line 13 x 1,000)	84,136
16		
17	SRM Capacity Charge per MW-Day (Line 15 / 365)	230.51

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21534

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on January 23, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 23rd day of January 2025.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

Service List for Case: U-21534

Name	On Behalf Of	Email Address
Amanda Urban	We Want Green, Too	aurbanlaw@gmail.com
Amanda Urban	Soulardarity	aurbanlaw@gmail.com
Amit T. Singh	MPSC Staff	singha9@michigan.gov
Andrea E. Hayden	DTE Electric Company	andrea.hayden@dteenergy.com
Benjamin L. King	Utility Workers Union of America, Local 223	bking@michworkerlaw.com
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Christopher M. Bzdok	Natural Resources Defense Council (NRDC)	chris@tropospherelegal.com
Christopher M. Bzdok	Sierra Club	chris@tropospherelegal.com
Christopher M. Bzdok	Michigan Environmental Council	chris@tropospherelegal.com
Christopher M. Bzdok	Citizens Utility Board of Michigan (CUB)	chris@tropospherelegal.com
Courtney F. Kissel	International Transmission Company	ckissel@dykema.com
D. Samuel Heppell	Soulardarity	heppell@uchicago.edu
D. Samuel Heppell	We Want Green, Too	heppell@uchicago.edu
Daniel H.B. Abrams	Environmental Law & Policy Center (ELPC)	dabrams@elpc.org
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