

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. **U-21534**
(e-file paperless)

**MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
INITIAL BRIEF**

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DATED: October 3, 2024

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I. Introduction

(Citations in Section I:

Appendices A—E;

Exhibit A-11, Sched. A1;

ABATE v Public Service Comm, 430 Mich 33, 39 (1988).

Verizon Communications, Inc v FCC, 535 US 467, 481 (2002).

In re Detroit Edison Co, MPSC Case No. U-15244, 12/23/2008 Order.

In its initial filing, the DTE Electric Company (“DTE,” “DTE Electric,” or “Company”) projects that it will experience a total electric revenue deficiency of \$456.434 million for the test year ending December 31, 2025 (A-11, Sched A1); alternatively, Staff projects that DTE’s total electric revenue deficiency will be \$237.179 million. (Appendix A.) The primary reasons for Staff’s lower projected revenue deficiency are Staff’s lower amounts for: rate base, return on equity, return on both tree trim and Monroe regulatory assets, and operating expenses. This is highlighted as:

i. DTE’s projected total rate base is \$22.108 billion, while Staff’s total projected rate base is \$21.945 billion—\$162.560 million less than the Company’s. (Appendix B.) It is lower because Staff reduced the Company’s plant in service by \$166.406 million (including adjustments to production, nuclear, distribution, demand side management, information technology, and corporate staff), increased the depreciation reserve (an offset to total utility plant) by \$14.521 million, and reduced working capital by \$10.675 million. (Appendix E.)

ii. DTE’s proposed ROE is 10.5%. Staff’s recommended ROE is 9.9%. (Appendix D.) The intervening parties recommend ROEs below 9.9%. Staff’s lower ROE reduces the Company’s projected revenue deficiency by about

\$70.0 million. Staff's recommended ROE differs from the Company's by 60 basis points because Staff used several different ROE inputs.

- iii. DTE projects that its total company operating expenses will be \$4.432 billion, while Staff projects that it will be \$4.347 billion. Staff's projection is \$84.984 million less than the Company projects. (Appendix C.) Staff's proposed operating expenses are lower because Staff adjusted the Company's Operation and Maintenance (O&M) expense by \$105.424 million to reduce, among other things, generation, customer service, corporate support, and pension and benefits expense.

Staff's proposed disallowances are justified and well supported. Staff's recommendations strike the right balance between DTE's interests and its ratepayers' interests. Public utilities are entitled to a reasonable opportunity to earn a reasonable rate of return on their investments, *ABATE v Public Service Comm*, 430 Mich 33, 39 (1988), and ratepayers are entitled to just and reasonable rates. The just-and-reasonable-rate doctrine is "aimed at navigating the straits between gouging utility customers and confiscating utility property." *Verizon Communications, Inc v FCC*, 535 US 467, 481 (2002). Staff's adjustments are well within these bounds.

Staff's objective is recommending "just and reasonable rates that are fair to both ratepayers and the company." *In re Detroit Edison Co*, MPSC Case No. U-15244, 12/23/2008 Order, p 11. Although many of DTE's proposed rate increases are justified, many are not. In several instances, the Company has overreached by increasing its capital-expenditure and operating-expense projections beyond reasonable expectations. In other instances, the Company has ignored Commission practice and precedent and asked to recover expenses that it has requested before and been repeatedly denied. Staff's adjustments correct these excesses.

In conclusion, DTE does not need a \$456.434 million rate increase. However, considering the significant capital investments in its future, an increase appears warranted. Staff proposes a \$237.179 million rate increase and a 9.9% ROE, which gives the Company a reasonable opportunity to earn a fair rate of return while giving ratepayers access to safe and reliable energy at reasonable rates.

II. Test Year

(Citations in Section II:

Foley, 2 TR 89, 92.)

While not in agreement with the amounts proposed, Staff did not take issue with the Company's use of its projected test year of January 1, 2025 through December 31, 2025 in this case. Company witness Neal T. Foley describes the Company's projected test year. (Foley (Revised), 2 TR 89, 92.)

III. Revenue Deficiency

(Citations in Section III:

Appendices A, F.

Nichols, 6 TR 4936;

Exhibit A-11, Sched A-1, Ln 10;

Detroit Edison's 2010–2011 Rate Case, MPSC Case No. U-16472, 10/20/2011 Order.)

Staff, through its witness Robert F. Nichols, CPA, initially projected a revenue deficiency of \$239.833 million, a revenue requirement decrease of \$216.600 million from the Company's originally filed revenue deficiency of \$456.434 million

found on Exhibit A-11, Schedule A-1, Line 10. (Nichols, 6 TR 4936.) The main factors driving Staff's overall adjustment are Staff's lower rate base, its higher net operating income, and its lower required rate of return. (*Id.*) In this brief, Staff has updated its case and now projects a revenue deficiency of \$237.179 million, a revenue requirement decrease of \$219.255 million from the Company's originally filed revenue deficiency of \$456.434 million. (Appendix A, Ln 11.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Ln 14—20.

The \$219.255 million difference between the Company's proposed total revenue deficiency of \$456.434 million and Staff's proposed total revenue deficiency of \$237.179 million is due to the following adjustments (revenue requirement impact in millions):

Rate Base	\$(11.974)
Rate of Return	(75.866)
Revenue	(3.235)
O&M	(105.424)
Depreciation	(12.839)
Return on Tree Trim Reg. Asset	(8.6553)
Return on Monroe Reg. Asset	<u>(0.572)</u>
Total Staff adjustments (rev. req. impact)	\$(219.255)¹

IV. Rate Base

(Citations in Section IV.:

Appendices A, B, E, F;

Hecht, 6 TR 4888—90; Freeman, 6 TR 5083—89; DeCooman, 6 TR 5050—58, 5061—62; Armstrong, 6 TR 5216; Dauphinais, 6 TR 3416—17; Guillaumin, 6

¹ Appendix A, Ln 11; Calculations of impacts Appendix F, Ln 3—12.

TR 1627—1630, 1715—16, 1727—1742, 1595—98; Chindhade, 6 TR 4752—4755; York, 6 TR 3351—57; Matthews, 6 TR 5166-5170; Keegan, 6 TR 2686-2688; Sherman, 6 TR 4100; Farrell, 6 TR 2686; Rogers, 6 TR 5112—5113, 5120—22; Boutet, 6 TR 5134; Hill (Rebuttal), 6 TR 3072—75, 3086—3087; Kindschy 6 TR 5178-86; Davis, 6 TR 1891—94; Rogers, 6 TR 5116 – 5119; Sharma, 6 TR 2132—33, 2170—75; Uzenski 6 TR 1527, 1564—66; Fromm, 6 TR 5095—96; Coppola, 6 TR 3636—3637; Bennett, 6 TR 1974—79, 1922—29, 1958; Hartwick, 4 TR 856;

Exhibits A-12, Sched. B1, B5.1, B5.3, B5.8, B5.9; S-8.1, S-2; S-2, Sched B4; S-7.2, S-9.0; S-10.2; S-10.3; S-10.4; S-11; S-15.4; S-15.6; S-15.7; S-16.0; S-16.2; S-16.3; S-16.4; S-16.5; S-16.6; S-16.7; A-29, Sched T1; A-46, Sched KK4; A-13, Sched. C5.1, C5.2, C5.3, C5.5, C5.7.1; C5.9.2;

Sharma, 6 TR 2168-2169, 6 TR 2168, Table 1;

In re DTE Electric Company 2023 Rate Case, MPSC Case No. U-21297, Sharma 5 TR 1822, Figure 1;

In re DTE Electric 2022 Rate Case, MPSC Case No. U-20836 Sharma, 7 TR 1928.

Detroit Edison's 2010–2011 Rate Case, MPSC Case No. U-16472, 10/20/2011 Order.

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 12/1/2023 Order, pp 42—43.

In re DTE Electric 2022 Rate Case, MPSC Case No. U-20836, 11/18/2022 Order, pp 43—48.

In re Consumers Energy 2021 Electric Rate Case, MPSC Case No. U-20963, 12/22/2021 Order, p 112;

In re Consumers Energy 2020 Electric Rate Case, MPSC Case No. U-20697, 12/17/2020 Order, p 66.

In re Commission's Own Motion, MPSC Case No. U-21538.

In re Commission's Own Motion, MPSC Case No. 21492.)

“Rate base consists of the capital invested in utility plant, less accumulated depreciation [i.e., net plant], plus the utility’s working capital requirement.”

Detroit Edison’s 2010–2011 Rate Case, MPSC Case No. U-16472, 10/20/2011 Order, p 5. In this case, rate base also includes net capital lease property, net nuclear fuel property, less capital lease obligations.

A. Staff recommends a total rate base of \$21,945,429,000.

Staff recommends a total rate base of \$21,945,429,000, which is \$162,560,000 less than the Company’s initial projection of \$22,107,989,000. Staff’s rate base is \$162,560,000 lower than the Company’s because Staff adjusted the Company’s: 1) production, 2) nuclear, 3) distribution; 4) demand side management, 5) information technology, 6) and corporate staff capital expenditures. (Appendix E.) Staff’s capital expenditure adjustments are detailed in Section IV.B. Staff also adjusted working capital for: a) other accounts receivable, b) and regulatory asset—charging forward. (Appendix E.) Staff’s working capital adjustment is detailed in Section IV.A.5. below.

1. Staff recommends a net utility plant of \$20,499,380,000.

The first component of rate base is net utility plant. Net utility plant consists of total utility plant minus accumulated depreciation and amortization. Staff’s recommended total net utility plant is \$20,499,380,000. (Appendix B, Ln 8.)

Staff's proposed net utility plant is \$151.885 million lower than the Company's net utility plant of \$20.651 billion because of a \$166.406 million reduction to plant in service, and a \$14.521 million increase to accumulated depreciation and amortization. (Appendix B, Ln 2, 7, 8, Col d; Appendix E, Ln 54, Col c, d, e.)

a. Staff recommends a total utility plant of \$27,262,149,000.

The first component of net utility plant is total utility plant. (Appendix B, Ln 6, Col e.) Staff recommends a total utility plant of \$27,262,149,000, which is \$166,406,000 less than the Company's initial projection of \$27,428,555,000. (See Section IV.B. below and Appendix E for the capital expenditure adjustments.)

b. Staff recommends an accumulated depreciation and amortization reserve of \$6,762,768,000.

The second component of net utility plant is the accumulated depreciation and amortization reserve. (Appendix B, Ln 7, Col e.) Staff recommends accumulated depreciation of \$6,762,768,000, which is \$14,521,000 more than the company's initial projection of \$6,777,289,000. (Section IV.B. and Appendix E.)

2. Staff recommends net capital lease property of \$6,051,000.

The second component of rate base is net capital lease property. Staff recommends the Commission adopt the Company's projection of \$6,051,000. (Appendix B, Ln 9, Col e.)

3. Staff recommends net nuclear fuel property of \$162,350,000.

The third component of rate base is net nuclear fuel property. Staff recommends the Commission adopt the Company's net nuclear fuel property of \$162,350,000. (Appendix B, Ln 11, Col e.)

4. Staff recommends capital lease obligations of \$7,049,000.

The fourth component of rate base is capital lease obligations. Staff recommends the Commission adopt the Company's projection of \$7,049,000. (Appendix B, Ln 13, Col e.)

5. Staff recommends a total working capital of \$1,284,697,000.

The fifth component of rate base is working capital. The Company forecasted that its total working capital requirement for the projected test year will be \$1,295,372,000. (A-12, Sched B1; Appendix B; Appendix E.) Staff's working capital of \$1,284,697,000 is \$10,675,000 less than the Company's because Staff adjusted: a) other accounts receivable; b) and regulatory asset—charging forward. (S-2, Sched B4; Appendix E, Ln 56—58.)

a. Staff recommends a \$6,111,000 reduction to working capital—other accounts receivable.

Staff, through its witness Justin J. Hecht, recommended a \$6,111,000 reduction to other accounts receivable. (Appendix E, Line 56; 6 TR 4888.) The Company, in response to Staff's inquiry, confirmed that the account Other Accounts

Receivable has an embedded balance that is considered non-recoverable and non-utility related. (S-11.0.) Based on the record evidence in this case, and the Company's non-objection in rebuttal, Staff recommends that the Commission reduce the projected test year working capital by \$6,111,000.

b. Staff recommends a \$4,564,000 reduction to regulatory asset—charging forward. (Appendix E, Ln 57.)

Staff, through its witness Alan D. Freeman, recommended an \$8,000,000 disallowance to the Company's Business and eFleet Charger Rebates program as well as a \$1,000,000 disallowance for its Residential Customer Rebate program. (6 TR 5087.) Staff recommends a total of \$9 million in disallowances for the Company's Business and eFleet Charger Rebates and Residential Customer Rebates so that a determination of whether the programs are achieving intended goals may be seen before a further funding is allowed.

This also results in a \$4,564,000 reduction to the Company's regulatory asset – charging forward projection, per the testimony of Staff witness Hecht. (Hecht, 6 TR 4888.) Based on the record evidence in this case, Staff recommends the Commission reduce the projected test year working capital by \$4,564,000.

Further, Staff recommends that the Commission order the Company to provide further detailed information on the Rebate programs as well as the Emerging Technology Fund, the progress of the Charging Hubs program, the School Bus Charger program, and a deferral of discussion of the Company's Transportation Electrification Plan to a more appropriate proceeding. (6 TR 5084—89.)

i. EV Program Observations

The Company has provided testimony and exhibits regarding its current EV programs. Regarding that testimony, Staff provides its recommendations concerning federal EV funding, the School Bus Charger program, the Charging Hubs project, the Emerging Technology Fund's initial awards, the Business and eFleet Charger Rebates program, the Residential Customer Rebates program, and the Company's Transportation Electrification Plan (TEP).

Company witness Pina Bennett testified that the Company has spent \$51.3 million on EV programs to date. (Bennett, 6 TR 1923; Freeman, 6 TR 5083—86.) Staff witness Freeman noted that the Company has actively sought federal dollars for its various EV programs; however, given that there are various sources for these funds and that the Company has multiple EV programs Staff recommends that the Company in future rate cases provide a list of the various EV funds it has applied for and the amounts that it has been granted in order that future EV funding requests can be properly analyzed.

ii. Charging Hubs

The Company spent \$1.9 million in bridge period costs and \$3.5 million for projected test period costs on the Charging Hubs pilot. These costs went to defining roles, establishing partnership agreements, finalizing scope of work, launching site design and engineering RFPs in 2024 with start of construction to occur in 2025. Additional sites are being scouted for construction in 2025. Staff has concerns with progress of this project. In November 2022, the Commission authorized this project,

and it has not progressed at a cadence one might expect. (Freeman, 6 TR 5084.)

Staff recommends a more detailed explanation for the increasingly slow progress of this project in the next rate case and annual EV report. (Freeman, 6 TR 5087—89.)

iii. School Bus Chargers

Regarding School Bus chargers, Company witness Bennett testified that the Company spent \$2.0 million during the bridge period and intends to deploy in 2024. (Bennett, 6 TR 1922—23, 1929.) Staff is interested in the performance of this program as it develops and recommends the Company file a detailed report in its next rate case of the program's performance.

iv. Emerging Technology Fund

The Company has launched an annual grant program to fund pilots using the \$1 million Emergency Technology Fund approved in MPSC Case No. U-21297. (Bennett, 6 TR 1930.) Witness Bennett testified that there are three stages of review starting with initial screening by the EV team, cross-functional review by other business units, and final review by the Emerging Technology Fund Advisory Committee. (Bennett, 6 TR 1978—79.) These reviews continue until the funding is exhausted. Since this fund comes in part from the rate case process, Staff recommends that the Company 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. (Freeman, 6 TR 5084—85.)

v. Business and eFleet Charger Rebates

The Company's eFleet and Business Charger Programs are part of the Charging Forward Program with approval granted in Case No. U-21297 for a total Charging Forward Program funding of \$24.4 million, of which \$6.9 million was for eFleet Business Charger Rebates and \$11.7 million for Expansion's Business Charger Rebates through 2024. Due 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. The Company, according to Exhibit A-12 Schedule B5.9 is requesting \$16,002,000 for the Business and eFleet Charger Rebates. (Freeman, 6 TR 5087.)

Staff recommends an \$8 million disallowance for the Business and eFleet Charger Rebates. Staff notes that this portion of the Charging Forward Program is the largest portion of the Company's EV budget proposal. With the evidence of slowed approval and installation of chargers in these projects Staff recommends scaling back the rebate effort. Staff recommends this so that the Company can determine if the revised rebate plans are reaching the intended goals. (*Id.*)

vi. Residential Customer Rebates

The Company has spent \$4.5 million total in Residential Customer Rebates. Regarding low-income customers, Company witness Bennett testified that support has been focused on them because installation of a home charger can be a

significant barrier for these customers. Outdated wiring and breaker panels can add to installation costs, with the Company’s review of these costs showing a range from \$750 to \$7,580. (Bennett, 6 TR 1958.)

Staff agrees with the Company that its low-income customers do face challenges in EV adoption; however, Staff recommends a disallowance of \$1 million for the Residential Customer Rebate program. (Freeman, 6 TR 5087.) If the revised rebate programs have the impact the Company intends, then the Company can seek further funding in future rate cases. Until such proof of program effectiveness is provided, Staff recommends a disallowance.

vii. Transportation Electrification Plan

Staff witness Freeman testified that a TEP “documents how a regulated utility plans to address the operational, policy, and system impacts of electric vehicles in its footprint.” (Freeman, 6 TR 5085.) These plans 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.

In fact, the Commission opened Case No. U-21538 to be a repository for TEPs. In rate Case No. U-20836, the Commission first asked DTE Electric to file a TEP. (Freeman, 6 TR 5085—86.) On December 21, 2023, the Commission directed utilities to file a TEP on January 11, 2024, and DTE complied. The Commission will establish a process in MPSC Case No. 21492 for evaluating the TEP in MPSC

Case No. 21538, allowing for comments and other appropriate measures to take place in Case No. U-21538. (6 TR 5086.)

viii. Recommendations

In the instant case, Staff witness Freeman (6 TR 5088—89) recommended that the Commission order the following:

1. The Company provide a list of all federal EV dollars it has applied for and been awarded and to which programs those dollars are allocated;
2. The Company to discuss in detail the School Bus Charger program and its results in the next rate case;
3. The Company provide a detailed explanation for the slow pace of the Charging Hubs Project in the next rate case and annual EV report;
4. The Company provide a report on the results of the initial awards from the Emerging Technology Fund in the next rate case and continue in subsequent cases until the fund no longer exists;
5. Discussion and evaluation of the Company's TEP until a future date and more appropriate proceeding;
6. Disallow \$8 million for the Company's Business and eFleet Charger Rebates program; and
7. Disallow \$1 million for the Company's Residential Customer Rebate program.

For the reasons above, Staff requests that the recommendations of Staff, through its witness Freeman, be adopted.

B. Staff recommends several reductions to the Company's capital expenditures, along with some approvals.

As discussed above, Staff's total utility plant is \$166.406 million lower than the Company's because Staff adjusted the Company's: 1) production; 2) nuclear; 3)

distribution; 4) demand side management; 5) information technology; 6) and corporate staff. (Appendix E.) The adjustments are explained below.

1. The Commission should exclude \$80,839,000 from DTE's projected production capital expenditures.

Staff recommends the removal of \$80,839,000 in production capital expenditures, which reduces rate base by \$54,235,000. (Appendix E, Ln 16, Col. b and e.) The specific exclusions are discussed in the following subsections.

a. Staff recommends the capital spending associated with Steam Generation: Non-Routine Additions should be reduced by \$5,620,000. (Appendix E, Ln 3.)

Staff recommends two adjustments as described below.

i. Staff recommends capital expenditures for Steam Generation: Non-Routine should be reduced by \$3,710,000 for updates to actuals (Appendix E, line 1.)

Staff recommends capital expenditures for Steam Generation: Non-Routine should be reduced by \$3,710,000 for updates to actuals, which reduces rate base by \$3,572,000. (Appendix E, line 1.)

Staff witness Lisa M. Kindschy recommended that the additions for Non-Routine Steam Power Generation capital expenditures on Exhibit A-12 Schedule B5.1 page 2 be updated with actual amounts incurred through April 2024. The Company's case as filed included actual amounts through October 2023. Updating the additions to Non-Routine Steam Power Generation results in a decrease of

(\$579,559) for 2023 and a decrease of (\$3,130,502) for 2024 for a total reduction to the bridge period of (\$3,710,061). (6 TR 5178; S-16.0.)

In rebuttal, Company witness Margaret E. Guillaumin claimed that Staff's update for actual is not reasonable for several reasons. First, she argues that: "[t]he 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." (Guillaumin (Rebuttal), 6 TR 1728.) Witness Guillaumin later stated that "[c]apital projects are measured against the total project scope, the planned schedule, and the total funding level requested in the project approval documents." (*Id.*)

Staff disagrees with DTE witness Guillaumin's arguments. Staff submits that the timing of projects is equally important as the total cost of the project in setting reasonable rates. For example, if a project is delayed far enough into the future, it may no longer occur within the test year.

Staff did not take issue with the necessity or reasonableness of completing the projects themselves, but rather determined that updating for six months of actual spending versus using the Company's projections is reasonable for setting rates in this case. Furthermore, Staff 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.

ii. Staff recommends capital expenditures for Steam Generation: Non-Routine should be reduced by \$1,910,000 for Monroe Bottom Ash Conversion updates (Appendix E, Ln 2.)

Staff recommends capital expenditures for Steam Generation: Non-Routine should be reduced by \$1,910,000 for Monroe Bottom Ash Conversion updates, which reduces rate base by \$940,000. (Appendix E, line 2.)

During Staff's review of steam capital expenditures, Staff received updated project sheets that showed the Company reduced its proposed capital expenditures for the Monroe Bottom Ash Conversion project. Specifically, the amounts approved by upper management without contingency for the Monroe Bottom Ash Conversion in the updated project sheets showed a reduction to capital expenditures in 2025 of (\$1,909,812) compared to what the Company included in its case as filed. Therefore, Staff witness Kindschy recommended in testimony that the capital expenditures for the Monroe Bottom Ash Conversion project be reduced in the test year by (\$1,909,812) to match the Company's updated projections for spending on this project. (6 TR 5179; S-16.1.) The Company did not file rebuttal testimony on this adjustment.

- b. Staff recommends capital spending associated with Steam Generation: Routine should be reduced by \$60,433,000. (Appendix E, Line 7.)**

Staff recommends two adjustments as described below.

- i. Staff recommends capital expenditures for Steam Generation: Routine should be reduced by \$21,333,000 for updates to actuals through April 2024 (Appendix E, line 5.)**

Staff recommends capital expenditures for Steam Generation: Routine should be reduced by \$21,333,000 for updates to actuals through April 2024, which reduces rate base by \$20,686,000. (Appendix E, line 5.)

Staff witness Kindschy recommended an adjustment to the Routine Maintenance capital projects over \$1 million on Exhibit A-12 Schedule B5.1 pages 5—6 to update the capital expenditures with actual amounts incurred through April 2024. The Company's case as filed included actual amounts through October 2023. Updating routine maintenance capital projects greater than \$1 million results in an increase of \$1,224,761 in 2023 and a decrease of (\$22,558,252) in 2024 for a total reduction to the bridge period of (\$21,333,492). (6 TR 5179-80; S-16.2.)

DTE Electric filed rebuttal testimony against Staff's adjustment to update its routine maintenance capital expenditures with actual amounts that consisted of the same arguments the Company presented for Staff's adjustment to update non-routine capital expenditures with actual amounts. (Guillaumin, 6 TR 1727-29.) Please refer to section IV.B.1.a(i).

ii. **Staff recommends capital expenditures for Steam Generation: Routine should be reduced by \$39,100,000 for class cost estimate adjustments (Appendix E, line 6.)**

Staff, through its witness Kindschy, recommended capital expenditures for Steam Generation: Routine should be reduced by \$39,100,000 for class cost adjustments, which reduces rate base by \$24,303,000. (Appendix E, line 6.) Staff witness Kindschy recommended the Company's Routine Maintenance capital projects over \$1 million on Exhibit A-12 Schedule B5.1 pages 4-8 be reduced for certain project estimates. Specifically, she recommended that certain project cost estimates for May—December 2024 be reduced by 15%, and the costs for certain project estimates be reduced by 20% in 2025. Witness Kindschy explained that DTE Electric stated in response to discovery that it does not classify its steam, hydro or other power generation capital expenditures into the class cost levels specified by the Association for the Advancement of Cost Engineering (AACE). Rather, the Company uses three internal levels to describe the stage of a project: 1) PAT0 is used to accept a new capital project into the process, 2) PAT1 is where detailed engineering and procurement of long lead materials is undertaken, and 3) PAT2 is where construction of the project is completed. (Kindschy, 6 TR 5180.)

For routine capital projects greater than \$1 million, witness Kindschy recommended an adjustment to all projects that were at the PAT0 and PAT1 stage as Staff typically has made adjustments to projects that are not in their final stages and where the engineering is not complete since the estimates for these projects are less certain. For the projections for May—December 2024, Staff used the AACE

Class 4 expected accuracy reduction range since these estimates are not as far into the future and reduced these estimates by 15%. For all of 2025, Staff used the AACE Class 5 expected accuracy reduction range and reduced these estimates by 20%. (Kindschy, 6 TR 5180-81.)

Staff witness Kindschy testified that it was reasonable to reduce the 2025 cost estimates more than 2024 since most of the projects in 2025 are at the PAT0 stage of development and the projections are also farther into the future. In addition, Staff concluded that reductions to the cost estimates in the bridge and test period are reasonable given that the monthly actual amounts Staff received compared to the projections included in the Company's original filing are lower for January to April 2024. (Kindschy, 6 TR 5181; S-16.2, p 4.)

As explained above, Staff recommends a reduction of 15% for May—December 2024 of (\$10,648,865) and a reduction of 20% in 2025 of (\$28,451,121) for all PAT0 and PAT1 Routine Maintenance capital projects greater than \$1 million on Exhibit A-12 Schedule B5.1 pages 6—7. (6 TR 5181; S-16.4)

In rebuttal, DTE Electric witness Guillaumin argued that “[a] project being underspent (actual expenditures were less than a forecast) in the past does not justify reductions to future projections.” (Guillaumin, 6 TR 1733.) Staff disagrees. When spending for a half year is lower than the projections presented in a rate case, it does not give confidence to Staff that the spending will occur as projected for any of the cost estimates, and it, thus, merits adjustment. Staff is not disputing the

necessity of completing these projects, but rather the timing of when the spending will occur and how much is reasonable for inclusion in this rate case.

DTE Electric witness Guillaumin also testified that Staff misused the AACE class cost estimate guidelines because adjustments were made on estimates where the Company removed contingency. (Guillaumin, 6 TR 1731—33.) First, Staff used the AACE adjustment ranges as a general guide since the Company did not provide its own ranges nor how it developed its cost estimates. (Guillaumin, 6 TR 1595—98.) Therefore, Staff cannot be certain that the base amount requested in the project sheets is not inflated through the Company's own forecasting process for capital projects.

In addition, Staff used the lowest possible recommended adjustment for a Class 4 and Class 5 cost estimate, which takes into consideration that the Company removed the contingency identified in the project approval sheets. (S-16.3, p 3.) In addition, Staff argues that underspending compared to actual for a half a year shows a pattern that the projections that are included in this rate case 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 its forecast. Regardless of the reason, Staff argues that it is reasonable to reduce projects in the bridge and test year that are in earlier stages of planning.

- c. Capital spending associated with Other—Non-Routine should be reduced by \$14,683,000. (Appendix E, Ln 13.)**

Staff recommends five adjustments to other – non-routine, i) Blackstart Project 10570 and 20255; ii) Blackstart Project 17611; iii) Blackstart Project 18320; iv) Slocum Battery Project; v) Trenton Channel Energy Center BESS.

- i. Capital spending associated with Blackstart Project 10570 and 20255 should be reduced by \$611,000. (Appendix E, Ln 8.)**

Staff recommends capital expenditures for Blackstart Project 10570 and 20255 should be reduced by \$611,000, which reduces rate base by \$591,000. (Appendix E, Ln 8.)

- ii. Capital spending associated with Blackstart Project 17611 should be reduced by \$906,000. (Appendix E, Ln 9.)**

Staff recommends capital expenditures for Blackstart Project 17611 should be reduced by \$906,000, which reduces rate base by \$886,000. (Appendix E, Ln 9.)

- iii. Capital spending associated with Blackstart Project 18320 should be reduced by \$1,077,000. (Appendix E, Ln 10.)**

Staff recommends capital expenditures for Blackstart Project 18320 should be reduced by \$1,077,000, which reduces rate base by \$1,032,000. (Appendix E, Ln 10.)

Blackstart projects (see i.-iii above) should be approved with some disallowances, based on the following analysis.

Staff recommends partial disallowances for the Blackstart Projects' capital expenditure requests. Staff witness Jonathan J. DeCooman testified in support of three of the Company's Blackstart Projects with certain specific disallowances for insufficiently supported costs now that actual numbers for 2023 are available. (6 TR 5050.) As Company witness Guillaumin testified, "A black start unit is one that can startup utilizing only its own internal power without support from the grid in the event of a major grid blackout, such as the 2003 blackout." (6 TR 1627.) Staff witness DeCooman testified that the Company has included requests for "recovery of capital expenditures for the projects in the previous two DTE Electric rate cases: Case Nos. U-20836 and U-21297." First in MPSC Case No. U-20836, "the Commission disallowed all projected bridge and test year expenditures, citing information in the case that cast doubt on the Company's forecasted expenditures." *In re DTE Electric Company 2022 General Rate Case*, MPSC Case No. U-20836, pp 43-48. Second, in Case No. U-21297, the Commission adopted a partial disallowance of project costs on the basis that, while these projects are necessary to maintain grid security, Staff's adjustments to account for updated actual project expenditures and overestimations from the previous case to be reasonable. *In re DTE Electric Company 2023 General Rate Case*, MPSC Case No. U-21297, 2/1/2023 Order, pp 42—43.

Staff recommends partial disallowances for the Blackstart projects in this case as follows. (6 TR 5053.)

Blackstart Project #	Exhibit Reference	2023 Bridge Period Disallowance	2024 Bridge Period Disallowance
10570 & 20255	A-12, B5.1, page 2, line 37	(\$297,000)	(\$314,020)
17611	A-12, B5.1, page 2, line 38	(\$54,000)	(\$852,460)
18320	A-12, B5.1, page 2, line 39	(\$1,015,000)	(\$62,300)

Witness DeCooman testified that “[i]t is unreasonable to support the requested amounts when the Company has consistently overestimated costs for the Blackstart Projects,” as is evidenced by the latest available information, and consistent with the pattern of overestimation of these projects in previous electric rate cases. (6 TR 5054.) Therefore, the Staff requests that the Commission “adopt Staff’s partial disallowance of \$1,366,000 and \$1,228,780 in 2023 and 2024 bridge period capital expenditures for the three Blackstart Projects.” (*Id.*)

Contrary to the statements of its expert, the Company requests for the Blackstart Projects are too high.

Company witness Guillaumin presents the Company’s case for its Blackstart Projects. (6 TR 1627—1630; 6 TR 1727—1734 (Rebuttal).) Staff relies on the

updated monthly actual capital expenditures that post-date data relied on to develop the instant case. Staff submits that this is the most accurate representation. The Company admits that it actually spent \$1.4 M in 2023 capital for Blackstart. (Guillaumin (Rebuttal), 6 TR 1727.) The Company testified, however, that the variance between exhibit and actual project spends for these short few months is not a proper metric for measuring performance of project execution, nor adequate projection of final project results. (6 TR 1728.)²

The Company submits that differences evidence nothing with regard to the reasonableness and prudence of projects but rather projects can come with some “hiccups.” The Company states that there can be monthly timing variances within project execution that shift spend between months across the duration of project. The asserts that the Company expects the portfolio of project to meet overall projected spend. (Guillaumin, 6 TR 1729.) Therefore, the Company maintains that its projected numbers or more appropriate than actual numbers. Staff respectfully disagrees with the Company’s unwillingness to refresh its predictions based on actual numbers for Blackstart in 2023.

The Company bases its disagreement in part on the updated monthly capital spend for all projects in Exhibit A-12. Sch B5.2, p 2, not just the Blackstart Projects, the Company exceeds the amount in this exhibit by \$14.4 M. (*Id.*) Therefore, Company witness Guillaumin stated that recommendations to disallow project

² Staff witness Kindschy also addressed this portion of Company testimony, based on a methodology that Staff has used for non-routine capital in rate cases for several years.

funding based on recent actual monthly project spends should be disregarded.

Witness DeCooman's testimony zeroes in on a specific line item rather than looking at all projects; likewise, witness DeCooman's requested disallowances are specifically tailored. While the Company argues that it is unfair to adjust only when it has overestimated, and not underestimated on a project, non-routine projects are by their very nature those that do not have a good basis to be used to estimate from. Couple 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.

Witness Guillaumin argued that just because variance between forecast and actual data can be found on recent and short-term basis does not mean projects are over-funded or not be executed properly. Additionally, she testified that selection of only a subset of projects in which total actual spend is lower than forecast is not balanced approach and should therefore be rejected. (6 TR 1729.) Witness Guillaumin testified that in DTE Electric's last rate case, MPSC No. U-21297, the Commission found inclusion of majority of expenses for Blackstart project as reasonable. *DTE Electric Company 2023 General Rate Case*, MPSC Case No. U-21297. She further testified that the Commission agreed with the testimony of ITC into the confidential nature of these scoping documents and did not adopt Association of Businesses Advocating Tariff Equity (ABATE) and the AG's proposed disallowances based on not disclosing this information. (Guillaumin, 6 TR 1735.)

Witness DeCooman testified that for 2023, Staff based adjustments on variances between actual and projected amounts, which is the most accurate representation of project costs, and therefore the most reasonable method of calculating the amounts. (S-10.2; DeCooman, 6 TR 5056.) For 2024 expenses, Staff used the discrepancies between amounts forecasted in last rate case and actual capital incurred, averaging a 14% difference, used to make the adjustment. (DeCooman, 6 TR 5054; Guillaumin, 6 TR 1742.) The Staff submits that such adjustments are the most reasonable.

The Company disagrees with Staff's methodology. The Company argues that the Commission should find the fact that a project or group of projects underspent during a period compared to forecast does not demonstrate future project capital expenditure should be reduced and therefore Staff's \$1.2M adjustment to 2024 expenses should be disallowed. The Company's arguments are not, however, persuasive, as capital expenditures should be based on the most solid and accurate information available to date. This methodology is consistent with adjustments for non-routine capital projects which has been found reasonable and adopted in numerous electric rate case orders before the Commission. The Staff directs the Commission to the following cases and pinpoint citations to illustrate its point:

In re Consumers Energy 2021 Electric Rate Case, No. U-20963,
12/22/2021 Order, p 112;

In re Consumers Energy 2020 Electric Rate Case, U-20697,
12/17/2020 Order, p 66;

In re DTE Electric 2022 Rate Case, Case No. U-20836,
11/18/2022 Order, pp 43-48;

Staff submits that its adjustments for Blackstart are appropriate, as based on actual information, which is what was given the most weight in past cases.

ITC supports the Blackstart projects as important to the grid.

ITC witness Pushkar Chindhade testified that it is “important to note that these Blackstart resource projects are intended for use in critical grid events and preserving the security of these resources is of paramount importance.” (6 TR 4755.) ITC supports the Blackstart projects as being necessary to complete ITC system restoration plan. (6 TR 4754—55.) ITC submits that the Commission should approve the Blackstart projects as proposed with no further disallowances. (*Id.*) ITC, through its witness Chindhade, stated that Blackstart resources are absolutely critical to the electrical grid. Per ITC witness Chindhade Blackstart capable generation should be considered a high priority asset essential to energy infrastructure to state and broader region. Therefore, ITC submits that the Commission should support Blackstart projects as essential to this state’s energy security. (6 TR 4758.)

Both ABATE and Staff acknowledge that DTE has provided updated scoping documents with updated project estimates in this case. (*Id.*) ITC, through its witness Chindhade, recommended that the Commission approve the remaining costs for projects without disallowance or further conditions. (Chindhade, 6 TR

4752—55.) The Staff maintains, however, that DTE Electric can seek any remaining costs in its next rate case.

ABATE's reservations about Blackstart projects stem from lack of information.

ABATE's witness Jessica York stated that DTE requests \$25.181 million for 4 Blackstart projects. She stated that DTE claims support for the NERC Blackstart plan, but DTE submits that it cannot disclose details. She testified that the PMP documents for these projects, both redacted and non-redacted, do not appear to have been provided irrespective of whether or not an expert signed an NDA. (York, 6 TR 3351.) From the Project Management and Planning (PMP) documents, it is clear that there have been revisions and project schedules have changed, per witness York. However, due to redactions and details unknown, it is unclear whether the changes affect the likelihood these projects will be completed as planned during the bridge period. She testified that DTE provided limited information to support inclusion of these projects; therefore, ABATE recommends that the Commission disallow all projected capex from rate base. While the Commission found in the previous case that these projects were important to maintain grid security, witness York testified that ratepayers should not be responsible for unsubstantiated costs that have not been demonstrated to be reasonably likely to be incurred in the bridge period projected test year. (York, 6 TR 3352.)

ABATE disagrees with use of the societal cost test in DTE's base case benefit-cost analysis (BCA) for its Transmission Electrification Plan (TEP).

ABATE's witness James R. Dauphinais disagreed with MEIU witness Dr. Laura Sherman's arguments that the Commission should require DTE to account for societal benefits, including GHG and criteria pollutants in its benefit-cost analysis (BCA) for its Transmission Electrification plan (TEP). (Dauphinais, 6 TR 3416—17.) (Michigan Energy Innovation Business Council (Michigan EIBC), Institute for Energy Innovation (IEI) and Advanced Energy United (United) are collectively known as MEIU.) MEIU witness Sherman used the societal cost test (SCT) to determine the cost impact of a program on society as a whole. ABATE, through its witness James Dauphinais, does not object to the use of the SCT for informational purposes as a sensitivity, ABATE maintains that the Commission should not order use of SCT or inclusion of any societal benefits in DTE's base case BCA for its TEP. (Dauphinais, 6 TR 3417.)

Also, ABATE's witness testified that the Commission should not direct DTE to pursue or expand its TEP on the basis of societal benefits association with transportation emissions as that would amount to mandating electric ratepayers subsidize the cost of providing these claimed societal benefits. (*Id.*) Similar to ABATE's position, Anne Armstrong testified to the SCT's purpose in her rebuttal testimony on behalf of the Staff. The Staff also submits that the SCT has both benefits and limitations in a general rate case as will be discussed in greater detail elsewhere in this brief. (Armstrong (Rebuttal), 6 TR 5216.) Staff witness Anne Armstrong further testified to Staff's position on the SCT. See Section XI.

iv. Capital spending associated with Slocum Battery Project should be reduced by \$2,178,000. (Appendix E, Ln 11.)

Staff recommends capital expenditures for Slocum Battery Project should be reduced by \$2,178,000, which reduces rate base by \$2,131,000. (Appendix E, ln 11.)

Staff recommends adjustments to Slocum are well supported.

Staff recommends adjustments to Slocum based on amounts of overhead increased from the 2023 DTE General Electric rate case, MPSC Case No. U-21297. Staff witness DeCooman testified that the Company did not adequately support nature of cost increase. (6 TR 5055.) Staff, furthermore, found that the explanation provided by the Company did not align with adjustments to the forecasted project overheads. *In re DTE Electric Company 2023 General Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order. (*Id.*) The Company explained in rebuttal that increase in overheads driven by increases in material and labor costs on which indirect overheads calculated. (Guillaumin (Rebuttal), 6 TR 1741.) However, even this explanation is inconsistent with the updated costs being requested.

Allocation of overheads to Slocum, as with all other capital projects, are done on a monthly basis. Overhead costs charged to all capital projects are based on actual direct costs. Direct costs include costs like labor, material, and contract labor charged directly to projects. When asked to provide an explanation of why project overheads were increasing, the Company explained that “Overheads proportionately vary based on changes to material and labor costs.” (S-10.3.) In

addition to Staff finding this explanation to be nonspecific, Staff also finds it does not match up with the actual cost increases forecasted for this project.

Staff witness DeCooman demonstrated in his testimony that the Company's claim that project overheads vary proportionally with material and labor costs is untrue. Between 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, however, represents an almost 45% increase to that category. (*Id.*)

In its rebuttal, Company witness Guillaumin claims that in MPSC Case No. U-21297, the Company projected Slocum to cost \$34.7M, \$30.9M in direct costs and \$4.8M in indirect (overhead) costs. Overhead costs represent 14% of total project costs. In the instant case, Slocum was projected to be \$44.7M, \$37.8M in direct costs and \$6.9M overhead. Overhead would therefore represent 15% of total project costs. (Guillaumin (Rebuttal), 6 TR 1742.)

There are several issues with this explanation that make it inadequate to support the requested increase to project overheads. For starters, it appears that the methodology the Company is using to estimate project overheads is not the explanation provided in Exhibit S-10.3. (DeCooman, 6 TR 5056—58.) While the Company detailed in Exhibit S-10.3 that its estimates for project overhead vary proportionately with project materials and labor, in explanation of how the Company arrived at the filed increase, it justified this increase by demonstrating

that it varies proportionately with total project costs. (*Id.*) Clearly, there is a disconnect between the explanation provided in Exhibit S-10.3, and how the increase to project overhead was developed. This is evidenced by the difference between the relative increases in different cost categories calculated in Staff witness DeCooman's testimony, and the Company's calculation.

Even if the methodology provided by the Company in rebuttal is correct, the numbers that were used to justify the estimates were not accurate. The project charter for Slocum, which includes changes to the detailed cost forecast by category, shows that, prior to the forecasted changes, project indirects (overheads) over the forecast period totaled \$4.75 million of a total of \$33.5 million, or 14.2%. (S-10.4.) This compares to the updated forecasted overhead cost of \$6.9 million, of a total of \$44.7 million, or 15.5%. (*Id.*) While this discrepancy may seem relatively small, when considered in the context of the total project cost, a 1.3% discrepancy for a \$44.7 million project is approximately \$600,000 in unsupported costs. Given the lack of support and inconsistent application of the methodology provided, the Commission should find Staff's proposed disallowance of additional project overhead costs for Slocum as reasonable, and the disallowance should be adopted.

v. Capital spending associated with Trenton Channel Energy Center BESS should be reduced by \$9,910,000. (Appendix E, Ln 12.)

Staff recommends capital expenditures for Trenton Channel Energy Center BESS should be reduced by \$9,910,000, which is construction work in progress (CWIP) with an AFUDC offset. (Appendix E, Ln 12.) (Appendix E, ln 12.)

Staff's request to remove \$9.9 M from the from the Trenton Channel battery energy storage system (Trenton Channel BESS) is well-supported.

Staff witness DeCooman recommended removing \$9.9M in 2024/2025 capital expenditures from the from the Trenton Channel BESS based on uncertainty in the estimates for project work which does not have established contracts. (DeCooman, 2 TR 5061; Guillaumin, 6 TR 1738.) Staff also recommends an adjustment, removing 10% of 2024 subtotal and 20% of 2025 subtotal. (6 TR 5062.) The Company states that witness DeCooman does not explain how he arrived at these specific amounts. The Company states that it appears that DeCooman attempts to calculate spend not associated with contract works but included line 8 (OE and expert support – subject to contract) and funding in lines 9/10 (overheads/AFUDC) even though the majority of expenses through contract. The Company mischaracterizes Staff's adjustment. Staff's adjustment was made to all cost categories that do not have an executed contract, not just work that was not contracted at all. If the contract has not been executed the work is no more defined than non-contract work. Therefore, Staff submits that its adjustment is appropriate. Witness Guillaumin testified that the Commission should find that Staff's adjustment factors lack specific explanation and justification and contain inconsistent calculations. (Guillaumin, 6 TR 1739.) The Staff respectfully disagrees and recommends that it is appropriate to remove \$9.9M in 2024/2025 capital from the Trenton Channel BESS. (DeCooman, 6 TR 5061.)

d. Capital spending associated with MERC/Fuel Supply should be reduced by \$103,000. (Appendix E, Ln 15.)

Staff recommends capital expenditures for MERC/Fuel Supply should be reduced by \$103,000, which reduces rate base by \$95,000. (Appendix E, ln 15.)

Staff recommends one adjustment to the Company's MERC & Fuel Supply capital expenditures on Exhibit A-12 Schedule B5.2. Similar to Staff's request with respect to Steam capital expenditures, witness Kindschy testified to Staff's recommendation to update the months for which actual amounts are now known through April 2024. Updating MERC & Fuel Supply capital expenditures with actual amounts through April 2024 results in a decrease of (\$130,514) for 2023 and an increase of \$28,000 for 2024 for a total reduction to the bridge period of (\$102,514). (6 TR 5181; S-16.5.)

The Company did not file rebuttal testimony on this proposed adjustment; therefore, Staff recommends that the Commission adopt it.

2. The Commission should exclude \$45,550,000 from DTE's projected nuclear capital expenditures. (Appendix E, ln 22.)

Staff recommends five adjustments to nuclear capital expenditures, i) Nuclear Routine and Small Projects; ii) Nuclear Non-Routine and Large Projects; iii) Nuclear Routine and Small Projects; iv) Nuclear Non-Routine and Large.

i. Capital spending associated with Nuclear Routine and Small Projects should be reduced by \$7,870,000. (Appendix E, Ln 18.)

Staff recommends capital expenditures for Nuclear Routine and Small Projects should be reduced for updates for actuals through April 2024 by \$7,870,000, which reduces rate base by \$7,473,000. (Appendix E, Ln 18.)

Staff recommends that the Company's Nuclear Routine and Small Projects on Exhibit A-12 Schedule B5.3 pages 2—3 should be updated with actual amounts incurred through April 2024 obtained through discovery. Updating the Company's exhibit with actual amounts through April 2024 for Nuclear Routine and Small Projects results in a decrease of (\$1,442,207) for 2023 and a decrease of (\$6,428,078) for 2024 for a total decrease in the bridge period of (\$7,870,285). (Kindschy, 6 TR 5182; S-16.6 page 1.) DTE Electric filed rebuttal testimony generally on updating nuclear capital expenditures with actual amounts which will be addressed below.

ii. Capital spending associated with Nuclear Non-Routine and Large Projects should be reduced by \$7,874,000. (Appendix E, Ln 19.)

Staff recommends capital expenditures for Nuclear Non-Routine and Large Projects should be reduced for updates for actuals through April 2024 by \$7,874,000, which reduces rate base by \$7,522,000. (Appendix E, Ln 19.)

Staff recommends an adjustment for Nuclear Non-Routine and Large Projects on Exhibit A-12 Schedule B5.3 page 4 to update the capital expenditures with actual amounts incurred through April 2024 obtained through discovery. Updating the Company's exhibit with actual amounts through April 2024 for Nuclear Non-Routine and Large Projects results in a decrease of (\$371,147) in 2023

and a decrease of (\$7,502,363) in 2024 for a total decrease in the bridge period of (\$7,873,510). (6 TR 5183-84; S-16.6, p 2.)

In rebuttal, Company witness Davis stated that “[n]one of Witness Kindschy’s proposed reductions address a circumstance at Fermi 2 involving a performance variance.” (6 TR 1885.) Witness Davis defined a performance variance as “the work has completed or will complete at an actual expenditure higher or lower than expected.” (*Id.*) Staff witness Kindschy never stated a specific reason for its adjustment. Similar to Staff’s adjustment for Steam Generation capital expenditures, Staff does not know the reason that actual capital expenditures were lower when updating for actual amounts through April 2024. The Company could have included projections in this rate case that 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 its forecast. For these reasons, Staff determined that using actual spending available before internal deadlines was reasonable. In rebuttal, the Company argues that reviewing for variances in nuclear capital expenditures should occur three months after a refueling outage. (6 TR 1888.) Staff 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. For these reasons, Staff recommends the Commission

adopt Staff's adjustments to update nuclear capital expenditures for actual amounts through April 2024.

iii. Capital spending associated with Nuclear Routine and Small Projects should be reduced by \$12,227,000. (Appendix E, Ln 20.)

Staff recommends capital expenditures for Nuclear Routine and Small Projects should be reduced for apply cost estimates May 2024 through December 2025 by \$12,227,000, which reduces rate base by \$7,733,000. (Appendix E, Ln 20.)

Staff recommends a reduction to Nuclear Generation Routine and Small projects capital expenditures on Exhibit A-12, Schedule B5.3, pages 2—3, of 15% in May—December 2024 and a reduction of 20% in 2025. Similar to Steam capital expenditures, Staff requested in discovery what stage of planning each nuclear capital project was in. (Kindschy, 6 TR 5182.) The Company's response 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. Staff used the same approach as previously discussed for Steam capital expenditures based on the guidance in the AACE class cost estimate accuracy range for class 4 and 5 estimates and reduced projects in May-December 2024 by 15% and all projects in 2025 by 20%. (6 TR 5182-83.)

Staff's recommended reductions to 2024 and 2025 are further supported by the comparison of the actual capital expenditures through April 2024 to what the Company included in its case. Nuclear Routine and Small capital expenditures for December 2023 to April 2024 in total were 14.3% lower than the projections

included in the Company's original case. (6 TR 5183.) Therefore, Staff determined it is reasonable to reduce the remainder of 2024 by 15%, and to reduce the 2025 test year by 20% since those estimates are farther into the future with less certainty. This adjustment is also consistent with Staff's approach to Steam Generation capital expenditures. (*Id.*) For the reasons described above, Staff recommends a reduction of 15% for May-December 2024 of (\$3,737,313) and a reduction of 20% for 2025 of (\$8,490,015) for Nuclear Generation Routine and Small projects capital expenditures on Exhibit A-12 Schedule B5.3 pages 2-3. (6 TR 5183; S-16.6, p 1.)

The Company filed rebuttal testimony generally on Staff's reductions to nuclear capital expenditures related to the reductions in 2024 and 2025. In particular, the Company states in rebuttal that Staff applied misused the AACE guidelines by adjusting for amounts that already excluded contingency. (Davis, 6 TR 1891.)

First, Staff used the AACE adjustment ranges as a general guide since the Company did not provide its own ranges nor specifically how it developed its cost estimates. (Davis, 6 TR 1893—94.) Therefore, Staff cannot be certain that the base amount requested in the project approval sheets is not inflated through the Company's own forecasting process for capital projects. In addition, Staff used the lowest possible recommended adjustment for a Class 4 and Class 5 cost estimate, which takes into consideration that the Company removed the contingency identified in the project approval sheets. For these reasons, Staff recommends that

the Commission adopt Staff's adjustments to nuclear capital expenditures in 2024 and 2025.

iv. Capital spending associated with Nuclear Non-Routine and Large Projects should be reduced by \$17,579,000. (Appendix E, Ln 21.)

Staff recommends capital expenditures for Nuclear Non-Routine and Large Projects should be reduced for apply cost estimates May 2024 through December 2025 by \$17,579,000, which reduces rate base by \$13,234,000. (Appendix E, Ln 21.)

Staff recommends an adjustment to Nuclear Generation Non-Routine and Large projects capital expenditures on Exhibit A-12 Schedule B5.3 at page 4. Similar to the capital expenditures for Nuclear Routine and Small projects, Staff recommends that capital expenditures for Non-Routine and Large projects be reduced by 15% for May-December 2024 and all capital expenditures in 2025 be reduced by 20%. Staff used the same approach for Steam capital expenditures based on the guidance in the AACE class cost estimate accuracy range for class 4 and 5 estimates. (Kindschy, 6 TR 5184.)

Staff's recommended reductions to 2024 and 2025 are further supported by the comparison of actual capital expenditures through April 2024 to what the Company included in its case. The capital expenditures for Nuclear Non-Routine and Large projects for December 2023 to April 2024 in total were 12.9% lower than the projections included in the Company's original case. (*Id.*) Therefore, Staff concluded it is reasonable to reduce the remainder of 2024 by 15%, and to reduce the 2025 test year by 20% since those estimates are further into the future with less

certainty. As previously noted, this adjustment is also consistent with Staff's approach to Steam Generation capital expenditures. For all the reasons discussed earlier, Staff recommends a reduction of 15% for May—December 2024 of (\$9,895,210) and a reduction of 20% for 2025 of (\$7,683,968) to the Company's capital expenditures for Nuclear Generation Non-Routine and Large projects on Exhibit A-12 Schedule B5.3 pages 4. (6 TR 5184—85; S-16.6, p 2.)

As previously noted, the Company filed rebuttal on all its nuclear generation capital expenditures, therefore, Staff addressed the Company's rebuttal earlier in section IV.B.2.iii.

3. The Commission should exclude \$39,622,000 from DTE's projected distribution capital expenditures.

Staff recommends disallowance of \$39,622,000 of the company's distribution capital expenditures, which reduces rate base by \$23,131,000. (Appendix E, Ln 27.) The specific exclusions are discussed in the following.

a. Capital spending associated with total base capital underspend of \$25,202,000 should be disallowed. (Appendix E, Ln 24.)

Staff recommends capital expenditures for total base capital underspend should be reduced by \$25,202,000, which reduces rate base by \$23,131,000. (Appendix E, Ln 24.)

Staff adopts the position of AG witness Coppola regarding a Base Capital Expenditures disallowance of \$25.202 million for the historic 2023 calendar year.

Staff witness Boutet reviewed the Company's Base Capital expenditures in this case, although he did not recommend any adjustments in his direct testimony. AG witness Coppola revealed in his direct testimony that the Company had underspent its original 2023 projections by \$25.202 million. (Coppola, 6 TR 3617—18.) The Company acknowledged this underspend through Company witness Brian L. Hill's rebuttal testimony and DTE Electric agrees with the adjustment. (Hill (Rebuttal), 6 TR 3086—87.)

Staff is in support of the suggested disallowance to 2023 Base Capital expenditures of \$25.202 million due to underspend.

Clarification Regarding Staff Exhibit 12.1

Staff discovered that an error has been made in the filing of Staff Exhibit S-12.1, where in the second table of the exhibit, labeled 'DTE Fleet Capital Purchases Plan', the year 2024 appears twice. The final row of the table, where 2024 appears a second time, should instead read 2025. This can be confirmed by checking the spending amounts associated with 2025 shown in the first table of the exhibit, labeled 'DTE Fleet Spending – Capital Purchases', as it displays an identical value to the final row in the second table of the exhibit.

Staff withdraws its adjustments to the Company's Vehicle Fleet Capital Expenses of \$2.84 million for the bridge period and \$3.83 million for the test year. Staff now recommends that the Commission approve the original requests by the Company to their full extent of \$38.24 million for the 2024 bridge period and \$42.6 million for the 2025 test year.

Staff witness Ryan Boutet originally had suggested an adjustment to the Company's Vehicle Fleet Capital expenses, based on apparent underspending in both 2023 and 2024, and he now withdraws that object in support of the Company's costs. (6 TR 5134.) It was revealed in discovery that an ambiguity in Staff's questioning led to a misunderstanding on the Company's part, resulting in actual costs being reported as lower than previously projected costs. A supplemental discovery response was provided by the Company proving that costs shown in this case agree with previous projections. Company witness Theresa M. Uzenski addresses this miscommunication in her rebuttal testimony, confirming that the initial discovery response did not include capital maintenance or capitalized internal labor costs tied to the vehicles. (6 TR 1565—66.)

Intervenor witness Sebastian Coppola disagreed with the Company's proposal, suggesting a 2024 bridge period disallowance of \$4.564 million and a 2025 test year disallowance of \$8.187 million, arrived at by use of a three-year average plus inflation, insisting that the Company had not properly justified 2025 spending. (6 TR 3636—37.) Witness Coppola stated that the Company did not provide information regarding projected 2025 vehicle purchases and spending when asked, and therefore his methodology holds merit. The Company's discovery response on this topic, sent in response to Staff's request, did indeed include a spreadsheet

listing approximately 260 planned vehicle purchases for 2025, totaling to the Company's projection of \$42.6 million. (S-12.1 illustrates these figures as corrected by the Staff.) The Company also rebutted witness Coppola's disallowance through witness Uzenski's rebuttal testimony, where it is correctly pointed out that the Company had justified 2025 spending in its original discovery response. (6 TR 1564—65.)

Therefore, Staff supports the original Company requests for Vehicle Fleet Capital funding of \$38.24 million for the 2024 bridge period, and \$42.6 million for the 2025 test year.

Staff disagrees with the position of ABATE witness York to remove \$122.882 million from the Emergent Replacements category of the Base Capital program, siding with the Company.

ABATE witness York took exception to DTE's use of a five-year average of historical spend as the basis for expenditures during the bridge period and test year (6 TR 3357.) Witness York suggests the use of a four-year average of historical spend for this case, stating that the 2021 calendar year was anomalously bad for the Company, and its inclusion will serve to inflate DTE's projected capital expenditures in this case. (6 TR 3358.)

The Company responded to witness York through the rebuttal testimony of witness Hill. Witness Hill correctly pointed out that the Commission has consistently approved a five-year historic average as the most reasonable and prudent way to forecast Capital Emergent Replacement expenditures. (Hill (Rebuttal), 6 TR 3073—74.) Further, witness Hill argued that the exclusion of the

highest storm years serves to undermine the intent of a five-year average to account for year-to-year variability in weather. (Hill (Rebuttal, 6 TR 3072.) Witness Hill lastly pointed out that the Company also experienced the worst ice storm in its history, and six summer tornadoes, during 2023, stating that while the 2021 storms were called 'historic', it was not implied that such events would not occur again. (6 TR 3073.)

Staff agrees with Company witness Hill that it would be inappropriate to exclude 2021 from the five-year average spending for Emergent Replacements.

b. Capital spending associated with Strategic Capital programs: Microgrids should be reduced by \$30,138,000. (Appendix E, Ln 25.)

Staff recommends capital expenditures for strategic capital program: Microgrids should be reduced by \$30,138,000, which is construction work in progress (CWIP) with an AFUDC offset. (Appendix E, Ln 12; Appendix E, Ln 25.)

The Company does not dispute the Staff's recommendation that it is appropriate to disallow funding for Adaptive Networked Microgrid (NWA) ANM Pilot at this time. Through the testimony of its witness DeCooman, Staff recommended full disallowance from inclusion in rates for the NWA ANM Pilot in this rate case, and full crediting of the assumed contributions and grant funding to ensure this pilot is revenue requirement neutral. (DeCooman, 6 TR 5065; Hartwick, 4 TR 856.) The program was described by Company witness Shannen M. Hartwick. Staff is generally supportive of the pilot and value it could provide to Company, but Staff does not find it appropriate to include in rates when the status

of the Company's grant application is uncertain, particularly given indications from Company that it will not pursue the pilot if grant funding is not received.

The Company testified, through its witness Hartwick, that it appreciates Staff's support of project. (*Id.*) The Company will continue to work diligently with the Department of Energy to reach funding agreement and secure grant funding and commence engineering/design. Since the as filed in-service-date is 2027, a disallowance of the project does not impact revenue requirement. (*Id.*)

c. Capital spending associated with Strategic Capital: Project Contributions should be increased by \$15,718,000. (Appendix E, Ln 26.)

Staff recommends capital expenditures for strategic capital program: Project Contributions should be increased by \$15,718,000, which is construction work in progress (CWIP) with an AFUDC offset. (Appendix E, Ln 26.)

4. Staff recommends reducing demand side management capital expenditures by \$2,000,000.

Staff recommends reducing demand side management capital expenditures by \$2,000,000, which reduces rate base by \$1,390,000. (Appendix E, Ln 30.) The specific exclusions are discussed below.

- a. **The Commission should adopt Staffs disallowance of \$0.6 million in the bridge period and \$1.4 million in the projected test year, and recommendation concerning the Commercial and Industrial (C&I) Battery Storage Demand Response Pilot.**

Staff witness Cody S. Matthews summarized the Staff's positions regarding the C&I Battery Storage Demand Response Pilot, which was proposed as a two-participant pilot recommending that "the pilot be limited to a single customer at this time. Given this recommendation Staff also recommends a disallowance of \$2,000,000 for this program which is broken down as \$1.4 million during the bridge and \$0.6 million in the forecasted test year." (6 TR 5170.)

Company witness Keegan O. Farrell described the pilot. The Company is proposing to install two batteries on large customer sites. Each battery will be up to 250 kW/1 MWh in size with the potential to be located at up to two customer sites to reduce peak customer and system demand for an event of up to 4 hours. The Company has found its first participant, and the Company is targeting customers who are enrolled on the Company's D4 rate, D6.2 rate or D11 rate for a second participant. (Keegan, 6 TR 2686.) Company witness Farrell provided the current status of the pilot stating that batteries have been ordered and arrived in the US, the switchgear components were ordered in December of 2023, and one customer has been identified. (6 TR 2687.) Additionally, the Company stated that due to lead time of major equipment, installation for the first customer's site has taken longer than anticipated and is targeted for 2025. (6 TR 2687.) Company witness Keegan testified (6 TR 2688) that the Commission excluded the costs for the second

battery previously in Case No. U-21297. *In re DTE Electric Company 2023 General Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p 247. In that case, the Commission agreed with Staff's concern that the second half of the expenses would not be used and useful in the test year, due to the lack of a second customer for a two-participant pilot. (Keegan, 6 TR 2688.) The Company does not believe this will be an issue given that it expects to have both customers enrolled and the sites installed by the end of 2025, which is within the test year. (*Id.*)

In its testimony, Staff notes that while the Company has continued to attempt to identify a second customer, it has not been successful yet. (Matthews, 6 TR 5166.) Staff has concerns with the amount of time it has taken to find a second participant given that the Company has requested this pilot in its previous filing, U-21297. This equates to essentially looking for a second participant for 2 years unsuccessfully. While Staff has supported the idea of this pilot, Staff recommends the Company limit the current pilot to a single participant given the difficulty the Company has experienced in finding a willing second participant to date. This would allow the Company to focus on the single participant that has agreed to participate and allow more flexibility in the use of the second battery. (6 TR 5167.) Additionally, Staff has concerns with the current design of the program in that the Company is not currently planning to charge customers to participate in the program. (Matthews, 6 TR 5168.) While Staff recognizes that in the pilot phase of the program it may be beneficial to have no participation costs, Staff has concerns that this may not be representative of what a full program would look like as Staff

believes a full-scale program would require some level of cost to the participant. For this reason, Staff recommends the current pilot be limited to a single participant and a second pilot that looks at including a customer payment as a part of participation be considered. (6 TR 5170.)

In direct testimony MIEU witness Sherman recommended disallowing the proposed spending for the C&I battery pilot. She stated that “it does not appear that the circumstances upon which the Commission based its decision in the last general rate case (MPSC Case No. U-21297) have changed.” (Sherman, 6 TR 4100.) She went on to testify that she does “not believe that the Commission should approve the proposed spending for the second battery at this time.” (*Id.*) Witness Sherman recommends that if a second customer is found, the spending can be approved in DTE’s next rate case. (*Id.*) Staff agrees with witness Sherman’s recommendation in that it is premature to approve the cost for the second battery but continues to recommend the Company alter the pilot in to allow for a second pilot that looks at including a customer payment as a part of participation be considered. (Matthews, 6 TR 5170.)

In rebuttal, Company witness Farrell disagreed with Staff’s recommendation to continue the pilot with a single participant stating that the Company is working diligently to find a second participant. (Farrell, 6 TR 2713.) Witness Farrell further stated that by having a second customer with a different load profile and operating characteristics participate in the pilot, the Company can increase its learnings. (6 TR 2713.) Witness Farrell further rebutted Staff’s recommendation to

charge the second customer a fee for participation, once the Company has determined the value of the program through testing, stating that a fee only further hinders the Company from finding a second participant. Participants already have to pay an estimated \$100,000 to \$150,000 in up-front costs that are associated with the concrete pad and the necessary electrical work. (6 TR 2714.) Witness Farrell additionally pointed out that a few of the customers the Company spoke to opted to turn down the Company's offer to participate, citing up-front costs as a reason they choose not to participate. (6 TR 2714.)

While Staff agrees that charging an upfront fee may discourage and make finding a second participant more difficult, Staff notes that it would likely still be more representative of what the actual program may look like. If the Company were to move forward with a program of this nature, Staff finds it unsustainable that the Company would simply be giving customers very expensive storage at no cost, as the pilot is currently being conducted, with only installation fees paid for by the participant. (S-8.1.) Thus, bearing some costs for storage during the second phase of the pilot could avoid sticker shock in the future and better reflect the reality of the situation. Even the Company acknowledges that at the end of the pilot there will be costs, stating that the customer will have to purchase or rent the battery to continue the program. (6 TR 5169.) Because of that, while it may be more difficult to find a second customer, it is likely going to better gauge the customer interest in participating in this type of program for the long term if a fee is charged to the second customer in the second phase of the pilot.

While the Company has pointed out that a few customers opted out of participating in the pilot given the substantial upfront installation cost, these installation costs are minimal compared to the cost of the storage, which non-participating customers are subsidizing for this pilot as the participating customer is not required to pay for the battery. Staff also submits that buy-in will help facilitate more efficient use of the battery, resulting in higher savings from use of the battery to recoup costs for the customer. (Matthews, 6 TR 5168.) Having the second customer pay a fee makes sense because at the end of the program, the customer will have the opportunity to buy the battery, pay for its removal, or rent it. (S-8.2; 6 TR 5169.)

Given the realities of the cost of storage, as well as the high upfront costs for installation and the high cost to purchase the battery, Staff believes there is value in gauging a customer's interest in a program that will come at a premium to its customer before awarding full costs. Therefore, Staff continues to recommend the Commission disallow \$0.6 million in the bridge period and \$1.4 million in the projected test year, limiting participation at this time to one customer, until a second pilot is started, which includes a customer fee for participating.

5. The Commission should reduce the Company's information technology capital expenditures by \$55,832,000.

The Commission should reduce the Company's information technology capital expenditures by \$55,832,000, which reduces rate base by \$36,156,000. (Appendix E, Ln 50.) Staff addresses its recommended disallowances related to a) digital work

experience; b) level 2 cost estimates; c) and level 3 cost estimates in more detail below.

a. Capital expenditures for Infrastructure Operations – Digital Work Experience End of Life (EOL) should be reduced by \$547,000. (Appendix E, Ln 32.)

Staff recommends reducing Infrastructure Operations – Digital Work Experience EOL capital expenditures by \$547,000, which reduces rate base by \$323,000. (Appendix E, Ln 32.)

The Commission should disallow \$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 EOL. This recommendation is updated from direct testimony in which Staff recommended a disallowance of \$1.903 million in the bridge period (\$0.943 million in 2023 and \$0.960 million in 2024), and \$1.041 million in the 2025 test year. (Rogers, 6 TR 5120.)

Staff's recommendation in direct testimony was due to the Company's lack of support for the full forecasted expense. In testimony, DTE, through its witness Pankaj Sharma, provided a table showing the total number of laptops, desktops, monitors, and tablets replaced in 2023, 2024, and 2025. (Sharma, 6 TR 2132.) Through audit, Staff requested and received the cost DTE pays for each individual device. Staff calculated what the total expense should be, including 125 units each year at the most expensive cost for new hires and replacements. Staff's disallowance was the difference between the forecasted expense and the actual cost calculated for the devices. (S-15.7.)

In rebuttal testimony, Company witness Sharma disagreed with Staff's calculations, arguing that while Staff did include the \$0.8 million in 2023 to support ADMS, it did not include the other labor costs required for configuration, deployment, and testing. (Sharma, 6 TR 2174.) According to Table 2 in his rebuttal testimony, Company witness Sharma claims that the dollars Staff calculated for a recommended disallowance are all labor costs.

Staff disagrees with this claim. While Staff does agree that labor costs should be accounted for, the amount in Table 2 the Company claims is labor and the amount supported in Exhibit A-24 N3 as Projected Capital Labor Cost do not match. Further, the Projected Capital Labor Cost, the Projected Capital Non-Labor Cost (Contractor), and the Projected Overhead & Other Costs in Exhibit A-24 N3 do not equal the amount the Company states in Table 2 is fully labor.

Staff's updated recommendation 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 project to be included in rates.

As a result, Staff recommends the Commission disallow \$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 EOL project.

b. Staff reverses the ½ million disallowance in the 2022 historical year for EOL Asset Replacement project.

Staff reverses its recommendation from direct testimony for the disallowance of \$0.5 million in the 2022 historical year for the End-of-Life Asset Replacement project. (Rogers, 6 TR 5122.)

Staff's original recommendation was based on Company witness Sharma's direct testimony that the End-of-Life Asset Replacement project had a variance of \$6.5 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. (Rogers, 6 TR 5123.) He stated that \$6.1 million of that variance was due to the purchase of a 3-year license purchase of VMWare in 2022. (Sharma, 6 TR 2133.) However, Company testimony also included a standalone VMWare license project with a forecasted 2025 expenditure of \$5.6 million. (Sharma, 6 TR 2127.) Because the Company did not provide any explanation as to the difference in cost between 2022 and 2025 for the 3-year license purchases, Staff recommended a \$0.5 million disallowance for 2022.

However, in rebuttal testimony, Company witness Sharma explained that the Company is negotiating with the vendor to increase efficiency and manage workload

with other available technologies to reduce the license costs by \$0.5 million in 2025 and reduce the projected VMWare license renewal costs by 8%-10%. (Sharma, 6 TR 2175.) Staff accepts the Company's explanation and finds this expense to be reasonable and prudent. Therefore, Staff no longer recommends a \$0.5 million disallowance in the 2022 historical year for the End-of-Life Asset Replacement project.

c. Capital expenditures for IT Level 2 Cost Estimates should be reduced by \$42,602,000. (Appendix E, Ln 41.)

Staff recommends reducing IT Level 2 Cost Estimates capital expenditures by \$42,602,000, which reduces rate base by \$27,557,000. (Appendix E, Ln 41.)

The Commission should disallow 20% of the projected costs associated with IT projects with Level 2 cost estimates. This includes a capital expenditure disallowance of \$22.433 million in 2024 and \$20.169 million in 2025. (Rogers, 6 TR 5112.)

Level 2 cost estimates are incomplete, imprecise, and indefinite in nature. IT projects are given a Level 2 cost estimate a year or more prior to implementation. Additional reviews, final approval, and allocation in the budget occur after projects are given a Level 2 cost estimate. (*Id.*) Company witness Sharma rebuts Staff's position that Level 2 cost estimates are obtained prior to comprehensive review. He argues that projects in the n+2 planning cycle have secured approval in the financial base plan from the Technology Investment Committee, are supported by

the IT architecture team, and their estimates are developed through input and reviews from eight IT subject matter expert (SME) teams. (Sharma, 6 TR 2169.)

Staff maintains its position. Firstly, according to Company testimony in Case No. U-21297 Figure 1 DTE IT APC Cadence, a Level 2 estimation is built under the Detailed Estimate phase, and additional reviews for the project are conducted in the Pending Approval phase, prior to formal approval. (MPSC Case No. U-21297, Sharma, 5 TR 1822, Figure 1.) Secondly, 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. Examples include a change in scope, a change in schedule, the quote from the vendor, prioritization within the APC, or the necessity of the project altogether. While the projects and their estimates may be approved within the DTE planning process, these expenses are not under contract and are uncertain. Therefore, the full investment cost is unfair to pass onto ratepayers.

Staff submits that the level of cost information provided by the Company best correlates to the AACE Class III Estimate, with semi-detailed unit costs. AACE Class 3 estimates have a lower bound of -20%, meaning the actual project cost could be as much as 20% less than the estimate. (Rogers, 6 TR 5114.) In rebuttal testimony, the Company argued that Staff fails to recognize that the AACE Class 3 estimate has an upper range of +30%. Further, Company witness Sharma stated that the level of project definition deliverables defined and reviews completed for Level 2 cost estimates compare more accurately with an AACE Class 2 estimate

(-15%/+20%.) (Sharma, 6 TR 2166.) As indicated by the Company in MPSC Case No. U-20836, and unchanged in this case, Level 2 cost estimates are based on internal labor hours, hardware costs, software costs, any internal project management costs, and vendor quotes. (U-20836 Sharma, 7 TR 1928.) However, they still lack a definite scope and schedule. AACE Class 3 estimates have a lower bound of -20%, meaning the Company can over recover up to 20% of the project expense. The Commission does not have the ability to perform retroactive ratemaking and correct this issue if the full cost estimate is not spent. If 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 prudence. This position is consistent with its position taken and approved by the Commission in DTE Electric Company's previous two rate cases.

Moreover, Staff finds the Company's cost estimation methodology to be inaccurate and concerning. In testimony, Staff analyzed a spreadsheet provided through audit showing IT projects with their Level 2 cost estimate from DTE Electric's previous rate case, Case No. U-21297, and their Level 3 cost estimate in the instant case. Staff found that the percent difference between the Level 2 and Level 3 project costs ranged from -99.86% to 277.36% and of the 142 listed projects, 24 projects had no change in cost, the Company over recovered on 75 of the projects, and the Company under recovered on 43 of the projects. (Rogers, 6 TR 5113.) For the projects in which the Company over recovered on, the percent difference ranged from 0.11% to 99.86% with an average of 31.45% over-recovery. For the projects in

which the Company under recovered on, the percent difference ranged from 0.10% to 277.36% with an average of 37.28% under recovery. (S-15.4.)

In rebuttal testimony, the Company stated that when the instant case was filed, 87 projects had a Level 2 cost estimate. Since then, all 87 projects have undergone additional review cycles and progressed to the project planning and execution phase and are now Level 3 cost estimates. (Sharma, 6 TR 2168.) The Company provided Exhibit A-46 Schedule KK1 comparing the Level 3 estimates to the Level 2 estimates in the instant case, noting that 46 projects show a 0% variance, and 32 projects are within the variance allowance of a Level 3 estimate (less than 10%). (Sharma, 6 TR 2168, Table 1.) Staff finds this puzzling.

Staff's analysis in the instant case and the previous two electric rate cases has shown significant percent difference ranges between Level 2 and Level 3 cost estimates. It is surprising that all projects with Level 2 cost estimates have moved to Level 3 cost estimates with less than 10% variance. The Company did not provide any additional evidence or updated information regarding the progression of the 87 projects from a Level 2 cost estimate to a Level 3 cost estimate other than the Level 3 cost estimate. Providing this spreadsheet in rebuttal left Staff with insufficient time to analyze the information or request more information. Nevertheless, Staff is hopeful that the low variance is a result of improvement in the Company's cost estimation practices. However, it cannot be sure until the Company can prove in a future rate case that the Level 3 cost estimates are more accurately in line with the actual costs. Level 2 and Level 3 cost estimates are

inherently arbitrary numbers. Progression from a Level 2 to a Level 3 cost estimate can occur with little consequence as the projected cost is used primarily for planning purposes. The true test of precision will be evident by the comparison of these Level 3 cost estimates to their actual costs. At that time Staff may consider changing its position on DTE's cost estimation methodologies. For this reason and those discussed above, the Commission should disallow 20% of the requested expenses for the IT projects with a Level 2 cost estimate. This totals a capital disallowance of \$22.433 million in 2024 and \$20.169 million in 2025.

d. Capital expenditures for IT Level 3 Cost Estimates should be reduced by \$12,684,000. (Appendix E, Ln 49.)

Staff recommends reducing IT Level 3 Cost Estimates capital expenditures by \$12,684,000, which reduces rate base by \$8,276,000. (Appendix E, Ln 49.)

The Commission should disallow 10% of the costs associated with IT projects with Level 3 cost estimates. This includes a capital expenditure disallowance of \$11.861 million in the bridge period (\$11.315 million in 2023 and \$0.546 million in 2024), and \$0.823 million in the 2025 test year, as Staff witness Danielle Rogers testified. (Rogers, 6 TR 5116– 5117.)

Staff believes Level 3 cost estimates are inaccurate in nature. (Rogers, 6 TR 5117.) Using a spreadsheet of IT projects with Level 3 cost estimates provided through audit in Case No. U-21297, Staff compared the then Level 3 cost estimate with the actual cost in the instant case and found that the percent difference of the costs ranged from -100% to 1269%. (S-15.6.) The Company over recovered on 70 of

the 125 projects with an average percent over recovery of 38.31% and 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% and without them, the average percent under recovery decreases to 44.34%. (*Id.*) These cost variances are 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.

Company witness Sharma rebuts Staff's analysis. He states that Exhibit S-15.6 only offers a partial view of the project costs and should not be used to determine a 10% disallowance for Level 3 projects. He argues that total costs approved for cost recovery in Case No. U-21297 should be compared to costs submitted as part of the instant rate case within the 36 months ending December 31, 2024. (Sharma, 6 TR 2170.) Further, the Company provided their own analysis of the 70 projects identified as over recovered projects. (A-46, Schedule KK4.) The spreadsheet compared the total costs approved for recovery in Case No. U-21297 to the costs submitted as part of the instant rate case within the 36 months ending December 31, 2024. It states that 49 of the 70 projects were within the variance allowance, as they may contain actual costs and Level 1, Level 2 and Level 3 estimates, and should not be considered as part of the over recovery. (Sharma, 6 TR 2171.) Additionally, he states 13 of the projects were included in testimony with explanations of efficiency for why their variances exceeded 20% and should not be

reason for disallowance, and 8 projects were under recovered on due to a partial or full disallowance in Case No. U-21297. (*Id.*)

Staff does not agree with the Company's analysis and maintains its position. Firstly, the Company did not provide any explanation as to why the total costs approved for cost recovery in Case No. U-21297 should be compared to costs submitted as part of the instant rate case within the 36 months ending December 31, 2024, as opposed to Level 3 cost estimates in U-21297 being compared to actual costs in the instant case. Staff's purpose for its analysis was to determine the accuracy of project cost estimation in its progression through the Annual Planning Cycle. Actual costs would be the most precise, so Staff finds it important to determine how close to actual costs Level 3 cost estimates, the theoretically second to most precise costs, fall. Costs within a 36-month time period in both Case Nos. U-21297 and U-21534 will contain Level 1, 2, and 3 cost estimates, all of which Staff has found to be unreliable. Secondly, Staff finds many flaws within the spreadsheet and some of the projects noted as "within the variance allowance" are not. For example, the Cloud Infrastructure and Supporting Capabilities project states it has a -53% variance which is "within the variance allowance". Staff questions how a -53% variance is within the allowance. Even an AACE Class 5 estimate, the least mature cost estimate, has a lower bound of -50%. Other examples are the High Volume IVR Overflow project with a variance of -96% and the SAP Cloud Platform - Foundational Additions project with a variance of -65%, both "within the variance allowance". Thirdly, Staff emphasizes that the Company chooses to file its rate case

application using a projected test year and forecasted expenses instead of actual expenses. Staff's goal is to ensure that the expenses (which in this case includes projected expenses) passed onto ratepayers are reasonable, prudent, and the closest to actual costs as possible.

Staff would be remiss if it did not point out that the Company's use of the total costs approved for cost recovery in MPSC Case No. U-21297 in its Exhibit A-46 Schedule KK4 proves the validity of Staff's 20% adjustment for Level 2 cost estimates. In MPSC Case No. U-21297, Staff recommended, and the Commission approved a 20% disallowance for projects with Level 2 cost estimates. The Overall Project Cost Approved in U-21297 would contain that 20% disallowance. The variances of over recovery would be much lower without the adjustment, meaning the Company would have over recovered by much more. And for many of the projects, the variances of under recovery may have crossed over into negative variances, or over recovery, without a 20% adjustment.

Staff chose a 10% disallowance for projects with Level 3 cost estimates as the information provided by the Company in U-20836 and unchanged in this case for the basis of Level 3 cost estimates best correlates to the AACE Class 1 estimate, with more detailed costs. (Rogers, 6 TR 5118–19.) As indicated by the Company, a Level 2 project transitions to a Level 3 project when the project is approved for project execution and the scope, cost, and schedule are managed. (MPSC Case No. U-20836, Sharma 7 TR 1928.) AACE Class 1 estimates have a lower bound of -10% meaning the actual cost could be as much as 10% less than the estimate. Staff

recommends a 10% adjustment to reflect the amount that the Company could over-recover from Level 3 project cost estimates. (Rogers, 6 TR 5119.) If the Company spends more than 90% of the projected cost, it can always seek recovery in the next rate case. Therefore, the Commission should disallow 10% of the projected expenses associated with IT projects with Level 3 cost estimates. This totals \$11.861 million in the bridge period (\$11.315 million in 2023 and \$0.546 million in 2024), and \$0.823 million in the 2025 test year in capital expenses.

6. The Commission should reduce the Company's Corporate Support capital expenditures by \$1,440,000.

Staff recommends reducing Corporate Support capital expenditures by \$1,440,000, which reduces rate base by \$1,012,000. (Appendix E, Ln 53.) Staff specifically recommends disallowance of \$720,000 capital expenditure spending categorized as "Other Miscellaneous" for both 2024 and 2025 because the spending isn't for specified work and cannot be judged for reasonableness and prudence.

The Company's witness Uzenski testified that the Company is requesting approval of \$1.7 million for environmental management. (Uzenski, 6 TR 1527.) These funds would be used "evaluating and developing technologies and controls to provide cost effective solutions in meeting environmental compliance and energy requirements." In addition, this funding would be used for minor items for staff groups, to be offset by investment recovery salvage sales. Staff witness Lauren Fromm testified that Staff recommends a disallowance of \$720,000 for both 2024 and 2025. (Fromm, 6 TR 5095—96; A-12 Sched B5.8; S-9.0.) She testified that the

reason for the disallowance was that \$1.2 million would be used for underground storage tank removal and cleanup with 40% for planned work and 60% for emergent spend. Because the emergent spend is not for any specific work and cannot be judged for reasonableness and prudence it would not be reasonable to pass these costs to customers.

V. Capital Structure and Rate of Return

(Citations in Section V:

Vanglider, 6 TR 2812; Ufolla, 6 TR 5009, 5011-5014, 5017-5026; Coppola, 6 TR 3657, 3664—68, 3670—74; Walters, 6 TR 3423, 3459, 3463, 3474, 3482-3485, 3489-3491; Villadsen, 6 TR 2407, 2436, 2439, 2441; Bandyk, 6 TR 3748, 3760—3761; Lepczyk, 6 TR 2556, 2564—65; Perry, 6 TR 4731-4743; Stults, 6 TR 4252-4256.)

In its initial filing, the Company, through its witness Kirk M. Vanglider, requested an overall cost of capital of 5.92% (Vanglider, 6 TR 2812) with a return on equity (ROE) of 10.50%, as testified to by Company witness Dr. Bente Villadsen.

(Villadsen, 6 TR 2407.) Staff, through its witness Joseph E. Ufolla, recommends a lower cost of capital of 5.66%. (Ufolla, 6 TR 5009.) Staff recommends an ROE range of 9.30% to 10.30% and used 9.90% as its recommended ROE in its overall cost of capital determination. (Ufolla, 6 TR 5026.) In its testimony, Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (Ufolla, 6 TR 5013—14.)

Likewise, the Attorney General (AG), ABATE, Citizens Utility Board (CUB), Michigan Environmental Council (MEC), and Walmart witnesses recommended lower overall cost of capital and ROE figures as well. The AG, through her witness

Sebastian Coppola, suggests an overall cost of capital of 5.67% with a ROE recommendation of 9.85%. (Coppola, 6 TR 3657.) ABATE, through its witness Christopher C. Walters recommends an overall cost of capital of 5.57% with a ROE of 9.60%. (Walters, 6 TR 3423.) CUB and MEC share a cost of capital witness, Matthew Bandyk, who testified to an overall cost of capital of 5.45% with a ROE recommendation of 9.30%. (Bandyk, 6 TR 3748.)

Walmart and Ann Arbor (AA), through their respective witnesses, also recommended a lower ROE, which would imply a lower cost of capital. Walmart, through its witness Lisa V. Perry, recommends an ROE of 9.62%. (6 TR 4731—43.) However, Walmart does not provide a specified overall cost of capital recommendation. AA's witness Dr. Melissa Stults does not provide a specific ROE recommendation but argues that DTE's ROE recommendations have routinely been "unreasonably high." (6 TR 4252—56.) Staff maintains its recommendation of a 5.66% overall cost of capital with a 9.90% ROE, and the Commission should approve Staff's recommendation based on the reasoning provided below.

A. Capital Structure

Staff did not adjust the Company's recommended balances for cost of capital items. Additionally, Staff does not dispute the Company's recommended cost rates for preferred stock, job development investment tax credits, or net deferred income tax.

B. Long Term Debt Rate

The Company, through its witness Timothy J. Lepczyk, requested a long-term debt rate of 4.24%. (Lepczyk, 6 TR 2556.) Staff, through its witness Ufolla, disagreed with the Company's projections and recommends a long-term debt rate of 4.21%. (Ufolla, 6 TR 5011.) This adjustment is due to Staff using a more recent treasury projection for the new issuances. (Ufolla, 6 TR 5011—12.)

In rebuttal, the Company disagreed with Staff's change to the debt rate. (Lepczyk (Rebuttal), 6 TR 2564—65.) However, the Company did not submit any testimony to dispute Staff's rate or to prove it unreasonable. Instead, the Company simply updated its own projections to re-iterate its initial position. There was no substantive argument against Staff's position, thus the Commission should approve a long-term debt rate of 4.21%, as recommended by Staff, in the instant case.

C. Short Term Debt Rate

The Company requested a short-term debt rate of 5.76%. (Lepczyk, 6 TR 2558.) Staff disagrees and recommends a 4.96% rate for short term debt. (Ufolla, 6 TR 5012.) The difference between these was that Staff used a more recent Short-term Overnight Financing Rate (SOFR) projection. (6 TR 5012—13.)

In rebuttal, Company witness Lepczyk updated the Company's projections to 5.73%. (Lepczyk, 6 TR 2565.) Although this adjustment is in the direction of Staff's figure, it is still too high. The Commission should approve a short-term debt rate of 4.96%, as recommended by Staff, in the instant case.

D. Return on Equity

In its testimony, Staff recommended an ROE range of 9.30% to 10.30% and used 9.90% as its recommended ROE in its overall cost of capital determination. (Ufolla, 6 TR 5013.) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (6 TR 5013-5014.) Since DTE Electric is not publicly traded, Staff used a group of thirteen publicly traded electric utility companies to help establish a reasonable cost of equity range for the Company. Staff used six criteria to establish its proxy group; a proxy company must 1) be listed as an Electric Utility by Value Line, 2) have data available from all Staff sources to complete the Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) analyses, 3) be currently paying dividends to shareholders, 4) must not be the target of a merger or acquisition, 5) must have a credit rating of Baa1/BBB+ or higher, and 6) must have a net plant of \$10 billion to \$80 billion. (6 TR 5015.) The proxy group's statistics were used to provide a reasonable approximation of the Company's required cost of equity in Staff's DCF and CAPM cost of equity models. Additionally, Staff utilized a risk premium analysis and a review of other state commission ROE decisions in its determination of a recommended cost of equity for DTE Electric. (Ufolla, 6 TR 5014.)

The Company's cost of capital witness Villadsen, sponsored DTE Electric's 10.50% ROE recommendation. (6 TR 2407.) Witness Villadsen submitted rebuttal disputing certain portions of Staff's ROE analysis and 9.90% recommendation. Additionally, the AG recommends an ROE of 9.85% (6 TR 3657) and ABATE

recommends an ROE of 9.60%. (6 TR 3423.) CUB and MEC both recommend an ROE of 9.30%. (6 TR 3748.) For the reasons above and as stated in testimony, the Staff recommends that the Commission approve a 9.90% ROE.

E. DCF Model

The DCF model assesses investors value stocks by ‘discounting’ expected future cash flows, attributed to securities, to present day. This ‘discounting’ process applies a capitalization rate to the future cash flows, both dividends and capital gains.

Staff obtained the data for its DCF analysis using statistics from its proxy group and growth estimates from industry experts. Staff’s DCF analysis yielded a median ROE estimate of 9.71%. (Ufolla, 6 TR 5017.) The AG performed its own DCF analyses as well. The AG’s models indicated an average required ROE of 9.26%. (Coppola, 6 TR 3664.) ABATE presented multiple DCF analyses which have average outputs ranging from 8.83% to 10.43%. (Walters, 6 TR 3459.)

The Company presented DCF analyses which ranged from 9.4% to 11.2%, and concluded from these that its DCF supported a 10.0% to 11.0% ROE. (6 TR 2439.) Staff’s testimony also addressed the Company’s DCF analysis and ROE estimate. Staff, through witness Ufolla, disagreed with the Company’s DCF models because they include a version of the After-Tax Weighted Average Cost of Capital (ATWACC) approach within its DCF models. The issues Staff raised about the ATWACC were that the Commission has not historically accepted it, the use of market equity values, and that ATWACC is geared primarily towards determining

overall cost of capital and not suitable for determining a fair and reasonable ROE in rate cases. (6 TR 5018.) ABATE and the AG also addressed the ATWACC methodology, coming to the same conclusion as Staff that it is unfit for use in determining a reasonable ROE. (6 TR 3482—85; 3665—68.)

F. CAPM

The CAPM model infers that investors are exposed to two types of risk, diversifiable (firm specific) and non-diversifiable (market) risk. The CAPM suggests that an investor is fully invested in a portfolio of stocks and thus eliminates, or greatly reduces, firm specific risk and is only exposed to market risk. The risk of an asset and thus the investor's required return is a function of the risk of that asset compared to the market. This market risk is characterized by the beta coefficient. Therefore, to estimate a cost of equity using the CAPM, one needs a risk-free rate, an estimate of beta for the proxy group, and a market return for a wide portfolio of assets. Staff used a long-term U.S. Treasury bond yield forecast for its risk-free rate, the proxy group betas from Value Line, and a market return from a wide variety of assets from 1928—2023. (6 TR 5019—21.) Staff's CAPM analysis produced an average ROE estimate of 10.23% and a median of 10.31%. (6 TR 5021.) Staff witness Ufolla pointed out that the CAPM ought to be considered a high-end estimate in current economic conditions. (6 TR 5021—22.) AG witness Coppola also produced a CAPM which resulted in a 10.57% ROE output. (6 TR 3670—71.) ABATE witness Walters performed multiple CAPM analyses with outputs ranging from 8.58% to 12.27%. (6 TR 3474.)

Company witness Villadsen presented CAPM analyses ranging from 10.8% to 11.7% and concluded from these that its CAPM supported a 10.75% to 11.75% ROE. (6 TR 2436.) Staff's testimony also addressed the Company's CAPM analyses and corresponding ROE estimates. Staff disagreed with the Company's use of the ECAPM and Hamada Adjustment. (Ufolla, 6 TR 5022—24.) Staff witness Ufolla reiterated Staff's disapproval of the ATWACC adjustment as the Hamada adjustment used in the Company's CAPM is of the same nature. (6 TR 5023.) Similarly, both the AG and ABATE witnesses also disagreed with the Company's use of the ECAPM and Hamada Adjustment. (6 TR 3489-3491, 3671-3672.)

G. Risk Premium

The risk premium approach examines the spread between historical electric utility realized stock returns and historical composite utility bond yields and develops a cost of equity estimate by incorporating the historical data with current utility-bond data. Staff used a return period of 1931 through 2023 to obtain its historical market risk premium. Staff used average yields for A-rated Utility bonds from Value Line as well as a projected Treasury bond yield. (6 TR 5024.) The risk premium model produced historical ROE estimates of 10.05% for Utility bonds and 8.63% for the treasury-based method. (6 TR 5025.) The AG and ABATE also provided Risk Premium analyses. The AG's Risk Premium model yields a result of 10.1%. (6 TR 3673.) ABATE's Risk Premium analyses show results ranging from 9.95% to 10.27%. (6 TR 3463.)

The Company uses regression-based Risk Premium models which outputs a result of 10.5%. (6 TR 2441.) Staff addressed the Company's Risk Premium analysis, noting that the use of approved ROEs only allows the Company to use about 30 years of data compared to Staff's nearly 100 years of data. (6 TR 5025.) The AG, MEC, and CUB, through their witnesses, also disputed the use of approved ROEs in a Risk Premium. (Coppola, 6 TR 3674; Bandyk, 3760—61.) ABATE also disputed the Company's Risk Premium approach. ABATE witness Walters cited the use of a risk-free rate that he testified was too high and an assumption of above average premiums. (Walters, 6 TR 3493.)

H. Other State Commissions' ROE Decisions

Staff reviewed the authorized rate of return decisions rendered by other state commissions from 2023 and 2024. The average authorized ROE from those decisions was 9.60% for 2023 and 9.66% for 2024. (Ufolla, 6 TR 5025.) The ROE data was provided by the Regulatory Research Associates, which is a unit of S&P Global Market Intelligence.

I. Response to Company Witness Villadsen's rebuttal critique

In rebuttal, Company witness Villadsen, on behalf of DTE Electric, criticized Staff's and other intervenors' ROE analysis. Most critiques are a rehash of her initial testimony and were thoroughly rebutted in Staff's and Intervenors' direct testimony, responding to her initial testimony. None of this rebuttal should persuade the Commission from approving Staff's Cost of Capital positions.

Responding to some of the larger points made in rebuttal Staff will address the use of the financial leverage adjustments and criticism of Staff's DCF inputs.

Simply put, the use of market equity adjustments, as proposed in this case by Company witness Villadsen, would result in a higher ROE in the instant case. This higher ROE would cause the value of DTE Electric as a subsidiary to increase and by extension would increase the market value equity for DTE Energy at the parent level. In turn, every case around the nation which include DTE Energy as a proxy result in a marginally higher ROE and the upward spiral begins. This leads directly into the circular situation that witness Coppola correctly explained in his testimony and is the exact reason Staff objects to the direct comparison between market and book equity. (Coppola, 6 TR 3666—67; Ufolla, 5018—19.) Although rates are rightly set at the utility level, it cannot be ignored that these rates have an impact on the parent companies of these utilities.

Company witness Villadsen criticized Staff's use of a negative growth rate in its DCF analysis. (6 TR 2505.) However, this is entirely misleading. As witness Ufolla testified, all available growth rates were used in his analysis. (6 TR 5017.) However, witness Ufolla acknowledged that it is common practice for some analysts to remove outliers such as the -12.34% growth rate for OGE that witness Villadsen is pointing to in her rebuttal and goes on to point out that there are also outliers on the high end. (6 TR 5017—18.) Witness Ufolla presented results that include all available data without bias, and as an alternative showed that the DCF results are lower if all outliers are removed. (*Id.*) So, although witness Villadsen's critique of

the inclusion of a negative growth rate does have some footing, it cannot be observed in a vacuum where only low-end outliers are removed. Instead, if outliers are removed on both the high and low end, the results of Staff's DCF model are several basis points lower.

VI. Adjusted Net Operating Income (NOI)

(Citations, Section VI:

Appendices A, A1.1, C, F;

Hecht, 6 TR 4889—90; Rogers, 6 TR 5112—24; Uzenski, 6 TR 1563; Sharma, 6 TR 2029; Nichols, 6 TR 4935—36; Wisniewski, 6 TR 2846; Bennett, 6 TR 1986; McMillan-Sepkoski, 6 TR 4925-28; York, 6 TR 3345—46. Coppola, 6 TR 3706; Rueckert 6 TR 4990—95; Ufolla 6 TR 5012-5013; Sparks (Rebuttal), 6 TR 2370—2382—2388; Hooper 6 TR 2931; Hooper, (Rebuttal) 2948, 2953, 2955; Lepczyk, 6 TR 2565; Fix, 6 TR 2861; Fix (Rebuttal), 2908; Braunschweig, 6 TR 3530—33; Jacob, 6 TR 4637—38; Watts, 6 TR 4678, 4683, 4688; Willis, 6 TR 2619.

Exhibits S-A1.1; A-11, Sched. A1.1; A-13, Schedules C1, C5, C5.8; Exhibit A-14, Schedule D1; A-16, Sched. F2; A-24, Schedule N3. 8.1; S-4, Sched. D3; S-4, Sched. D3; S-7.1; S-7.5; S-8.1; S-4, Schedule D1; S-17.0. S-17.1.

Michigan Compiled Laws (MCL) 460.10—11;

In re DTE Electric 2022 Rate Case, MPSC Case No. U-20836, 11/18/2022 Order pp 251-255;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297;

In re Consumers Energy 2024 Electric Rate Case, MPSC Case No. U-21389, 3/1/2024 Order p 148.

In re Commission's Own Motion, MPSC Case No. 12639, 12/20/2001 Order, p 10.

In re Detroit Edison's 2010–2011 Rate Case, MPSC Case No. U-16472, 10/20/2011 Order.

In re Commission's Own Motion, MPSC Case No. U-20757, Docket Entry 0525.

Staff submits that reduced to its essence, Adjusted NOI is the difference between a company's operating revenues and operating expenses for the projected test year. *Detroit Edison's 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 41.

A. Staff recommends an adjusted net operating income of \$1,175,319,000.

In its initial filing, the Company recommends an adjusted net operating income (NOI) of \$1,087,100,000, while Staff recommends an adjusted NOI of \$1,175,319,000, which is \$88,219,000 greater than the company's projection. (Appendix C, Col r, Ln 1, 49.)

Staff initially filed a projected net operating income of \$1,174,574,000, an increase of \$87,474,000 from the Company's originally filed net operating income of \$1,087,100,000 found on Exhibit A-13, Sched C1, Ln 17. (Nichols, 6 TR 4936.) In this brief, Staff has updated its case and now projects a net operating income of \$1,175,319,000. (Appendix C, Ln 49.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Ln 14-38.

Differences between the Staff's and the Company's total adjusted NOI are due to Staff adjustments to various Company revenue and expense projections as detailed below.

1. Staff recommends total operating revenues of \$5,468,651,000.

DTE projects that its total operating revenues will be \$5,465,416,000 in the projected test year, which is \$3,235,000 less than Staff's projection of \$5,468,651,000. (Appendix C, Col e, Ln 1, 48 and 49.) Staff made adjustments to sales revenue as detailed below.

a. Staff recommends sales revenue of \$3,999,211,000.

Staff recommends a total increase to the Company's electric sales revenue of \$3,235,000. (Appendix C, Col b, Ln 48.) This is composed of two adjustments, described below.

Before addressing the two adjustments, it is important to note that Staff recommends the Commission adopt the Company's forecasted annual electric deliveries of 44,189 Gigawatt Hours (GWh). (Exhibit A-15, Schedule E1, Page 1, Col (f), Ln 3).

With the appropriate deliveries forecast established, the adjustments recommended by Staff consist of the following.

i. Staff proposes a \$2,740,000 increase to present revenue by proposing its own Residential Income Assistance Credit customer count projection. (Appendix C, Ln 4.)

Staff recommends the Company's residential income assistance credit (RIA) projection be rejected in favor of Staff's more reasonable, supported projection, which totals a \$2,740,000 increase to present revenue.

In the direct testimony of Company witness Jason E. Sparks, the Company included recovery of 83,000 monthly RIA credits in the test year without support for its calculation nor methodology for its projection. (Sparks, 6 TR 2370.)

In the direct testimony of Staff witness Elaina Braunschweig, Staff noted it does not support the Company's projection and demonstrated through the audit responses in Exhibit S-17.0 that 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. (6 TR 3530—31.) Staff's counterproposal therefore utilized a 3-year historical average monthly credit disbursement totaling 56,134, which totals a \$2,740,321 revenue adjustment. (Braunschweig, 6 TR 3531; S-17.1.) Staff 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). (Sparks, 6 TR 2370; Braunschweig, 6 TR 3531.) By comparing the data, it is clear the numbers are different, which has historically been an issue in DTE Gas 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 MPSC Case No. U-20836, (as summarized in the 11/18/2022 Order pp 251-255) and was thought to be resolved in MPSC Case No U-

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 Commission's November 18, 2022 Order in MPSC Case No. U-20836, the Company was ordered to file a report to the 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 justified why its projection was more reasonable by providing a background on the main qualifiers for the automatic enrollment into the RIA: the Michigan Department of Health and Human Services (MDHHS), the Michigan Department of Treasury, or Michigan Energy Assistance Program (MEAP) grantees notifying utilities of a customer receiving a State Emergency Relief (SER) payment, a Home Heating Credit (HHC) energy draft, or one-time assistance payment, respectively, that would get applied to their account on the program manager's behalf. (Braunschweig, 6 TR 3532.) These 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 provided the table (below) depicting historical LIHEAP funding levels compared to monthly RIA enrollments. (Braunschweig, 6 TR 3533.)

Historical Michigan LIHEAP Funding		
Fiscal Year	Funding Level	Monthly RIA Enrollments (fiscal years) ³
October 1, 2019-September 30, 2020	\$ 197,960,572.00	39,013
October 1, 2020-September 30, 2021	\$ 435,542,243.25	54,773
October 1, 2021-September 30, 2022	\$ 166,875,852.32	65,521
October 1, 2022-September 30, 2023	\$ 269,598,865.00	77,107*
October 1, 2023-September 30, 2024	\$ 161,019,682	
Company TY		78,000

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. (Braunschweig, 6 TR 3533.) Staff then elaborated that average funding levels are the main determinants of RIA enrollment fluctuations, as annual LIHEAP funding levels fluctuate and MDHHS allocations impact a customer’s level of assistance, which impacts the number of RIA recipients not necessarily proportional to the LIHEAP funding level. (6 TR 3533.) Staff cited the American Rescue Plan and Inflation Reduction Act as examples of federal LIHEAP funding increasing and LIHEAP Energy Direct payments being released

³ Exhibit S-17.1

by MDHHS, which increased RIA enrollment from 2021 to 2022 in the above table. (6 TR 3534.) Staff clarified, though, that the elevated RIA enrollment from Covid-19 related federal funding increases is not expected to carry over into the test year since the above table exhibits LIHEAP funding returning to pre-pandemic levels and RIA eligibility is verified annually per the Company's tariff. (Braunschweig, 6 TR 3534.) To support Staff's projection, Staff cited Consumers Energy's electric rate Case No. U-21389, in which the Commission stated on page 148 of its March 1, 2024, Order that "[t]he Commission finds the Staff's position and the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue." The referenced ALJ recommendation from her PFD stated:

This PFD finds Staff's position persuasive. First, Staff's use of an entire year of RIA credits, rather than a simple comparison of customer counts for two months one year apart, more accurately demonstrates the trend in RIA enrollment and the fact that customers do not necessarily reenroll in the program. Second, the company's projection depends on actual enrollment in March of 2023, which appears to be the result of COVID-related LIHEAP disbursements, coupled with speculation about increased numbers due to more outreach and possible future funding from LIHEAP and DHHS. Lastly, the PFD agrees with Staff that without a tracker or deferred accounting, overprojection of RIA credits would result in Consumers retaining any overcollection. Thus, an accurate projection for this credit is even more important. [Braunschweig, 6 TR 3534-3535, quoting MPSC Case No. U-21398, 12/21/2023, PFD, p. 379.]

The Commission should therefore continue its approval of utilizing a 3-year historical projection, especially since the Company did not provide a calculation for how it reached its projection and its reasoning for utilizing its projection method is

unclear. If the Commission, however, accepts witness Sparks' argument that 2023 data should be included in the RIA projection, 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.

In rebuttal, Company witness Sparks argued that Staff's exclusion of 2023 RIA data is unwarranted, as he deemed the difference in what was reported in his testimony and what was reported in Part III Attachment 5(9) immaterial. (Sparks (Rebuttal), 6 TR 2387.) As is evidenced previously in this brief, 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. When given the opportunity to provide the accurate data through audit request in the instant case (S-17.0) as well as in its rebuttal testimony, the Company continued to avoid providing the data consistent with its Part III filing requirement methods. Accepting sub-par, inconsistent data reporting should not be accepted nor standardized by the Commission, as it undermines the ability for the Commission Staff and other parties to properly audit Company spending.

Company witness Sparks additionally argued in rebuttal that Covid-related assistance programs "such as Covid Emergency Rental Assistance (CERA) and Michigan Homeowner Assistance Fund (MIHAF), had broader eligibility criteria than the 150% Federal Poverty Level (FPL) required by RIA," which would not automatically qualify a customer for RIA. (Sparks, 6 TR 2388.) Staff reinforces

that it did not include all Covid-era assistance in its analysis; simply Covid-funding supplementing LIHEAP, as is clearly stated in direct testimony. (Braunschweig, 6 TR 3532—34.) Company witness Sparks further argued that LIHEAP is not a predictor of RIA enrollment trends since RIA enrollments increased after the large LIHEAP funding increase in fiscal year 2021. (Sparks, 6 TR 2388.) Staff cites direct testimony in which Staff witness Braunschweig already explained a potential reason for funding impacts having a potentially delayed impact on RIA enrollments in stating “but RIA enrollment will not necessarily increase proportional to the LIHEAP funding level. Especially if the United States Congress passes bills that allocate additional LIHEAP funding to each state that may not be required to be spent within the fiscal year like normal LIHEAP allocations are.” (Braunschweig, 6 TR 3533—34.) Company witness Sparks further claimed in rebuttal testimony that some RIA recipients will not reapply, but the majority will remain due to auto enrollment and self-attestation. (Sparks, 6 TR 2389.) Company witness Sparks, failed, however, to supply any evidence to support that claim. Staff cites witnesses Toyia Watts’ and Elizabeth Jacob’s testimony on behalf of DAAO as supporting evidence to the difficulties customers face with applying for assistance, including customer service representatives not promoting energy assistance when customers inquire. (Watts 6 TR 4678, 4683, 4688; Jacob, 6 TR 4637-4638.) (Soulardarity and We Want Green, Too are collectively the Detroit Area Advocacy Organizations (DAAO.)) Company witness Sparks stated in rebuttal testimony that “Even though supplemental funding may be eliminated, the number of households needing it will

not”—however, referencing witness Braunschweig’s direct testimony, the MEAP and LIHEAP funding is capped, which would limit the number of customers that could automatically enroll in the RIA annually, which reveals a flaw in the Company’s argument that the majority of RIA customers will remain due to auto enrollment. (Sparks, 6 TR 2389; Braunschweig, 6 TR 3532—33.) For this claim to be true, LIHEAP and MEAP funding would have to increase annually, instead of staying the same or decrease, as is the current reality. Company witness Sparks’ final argument against Staff’s RIA projection figure is that Staff’s citation of the ALJ’s recommendation in the PFD of MPSC Case No. U-21389 is not relevant because Consumers Energy utilized a comparison of RIA enrollment two months one year apart with enrollment being based on March 2023 enrollments and that without a tracker or deferred accounting treatment, Consumers Energy would retain any overcollection of revenue. (Sparks, 6 TR 2389.) Witness Sparks argued that DTE’s projection method included all 2023 enrollments as well as “a two-year historical average of the monthly average of enrollments” and that DTE has a tracker to correct for any over or under projection of enrollments. (*Id.*) Staff clarifies that Staff cited not just the ALJ recommendation, but the fact that the Commission adopted the ALJ’s recommendation in MPSC Case No. U-21389. (6 TR 3534—35.) Additionally, it is important to note that in doing so, the Commission accepted Staff’s projection method in that case, which was a 3-year historical average of enrollments, which is relevant to this case should the Commission retain its last-approved RIA projection method. Company witness Sparks’ argument that

DTE included all 2023 enrollments and a two-year historical average of the monthly average of enrollments, the Commission would have to accept the Company at its word without any additional supporting calculation as evidence, as the Company did not provide the calculation when Staff requested it, as shown in Exhibit S-17.0. As for the tracker that DTE has in place, 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.

For these reasons, it is prudent the Commission approve Staff's more accurate RIA projection based on supporting evidence and consistent data instead of a projection without data and calculations provided.

ii. Staff proposes a \$495,000 increase to present revenue by proposing its own Residential Senior Citizen Credit projection. (Appendix C, Ln 5.)

Staff recommends the Company's residential senior citizen credit (RSC) projection be rejected in favor of Staff's more reasonable, supported projection.

In the direct testimony of Staff witness Braunschweig, Staff raised the issue of the Company not providing testimony in its initial filing proposing a Residential Senior Citizen Credit (RSC) customer count projection yet including recovery of 104,224 monthly credit disbursements totaling \$5,315,424 in The Company's Schedule F-3 rate design file. (6 TR 3535.)

Staff's counterproposal was a 3-year historical average of the actual RSC credit disbursements totaling 94,525 monthly disbursements with a revenue increase of \$494,656. (6 TR 3536.)

RSC Credit Disbursements	
Year	Monthly Disbursements
DTE-Proposed Test Year	104,224
2022	95,329
2021	94,117
2020	94,129
2019	98,484
2018	109,091

Staff utilized the table depicted above to reinforce that RSC credit disbursements have been relatively stable for the three historical years and that, absent significant outreach, there is no evidence on the record to support the Company's significantly inflated projection. (Braunschweig, 6 TR 3536.) Staff additionally provided the table below from the Michigan Department of Health and Human Services to demonstrate that the percentage of Michigan residents aged 65 and older has hardly changed in the past 3 years, which does not support the Company's 8.5% projected increase in the senior credit. (Braunschweig, 6 TR 3537.)

**Total Population by Selected Age Groups
Michigan 2000-2022**

Year	Total	< 18		18 - 44		45 - 64		65 & Over	
		Number	Percent	Number	Percent	Number	Percent	Number	Percent
2022	10,033,757	2,109,759	21.0	3,483,209	34.7	2,560,711	25.5	1,880,078	18.7
2021	10,037,169	2,130,494	21.2	3,467,646	34.5	2,606,972	26.0	1,832,057	18.3
2020	10,069,614	2,154,501	21.4	3,475,155	34.5	2,650,941	26.3	1,789,017	17.8
2019	9,986,857	2,143,933	21.5	3,423,309	34.3	2,654,214	26.6	1,765,401	17.7
2018	9,984,072	2,162,182	21.7	3,415,762	34.2	2,692,772	27.0	1,713,356	17.2
2017	9,973,114	2,180,747	21.9	3,405,184	34.1	2,722,853	27.3	1,664,330	16.7
2016	9,950,571	2,193,921	22.0	3,396,407	34.1	2,742,849	27.6	1,617,394	16.3
2015	9,931,715	2,209,035	22.2	3,398,276	34.2	2,752,697	27.7	1,571,707	15.8
2014	9,929,848	2,230,079	22.5	3,409,065	34.3	2,759,488	27.8	1,531,216	15.4
2013	9,913,065	2,249,312	22.7	3,408,947	34.4	2,767,253	27.9	1,487,553	15.0
2012	9,897,145	2,272,804	23.0	3,405,183	34.4	2,776,100	28.0	1,443,058	14.6
2011	9,883,053	2,301,921	23.3	3,403,024	34.4	2,789,470	28.2	1,388,638	14.1
2010	9,877,510	2,334,175	23.6	3,409,975	34.5	2,767,075	28.0	1,366,285	13.8
2009	9,901,591	2,372,603	24.0	3,449,020	34.8	2,736,345	27.6	1,343,623	13.6
2008	9,946,889	2,418,879	24.3	3,507,576	35.3	2,699,413	27.1	1,321,021	13.3
2007	10,001,284	2,470,063	24.7	3,568,443	35.7	2,671,540	26.7	1,291,238	12.9
2006	10,036,081	2,503,548	24.9	3,634,296	36.2	2,628,794	26.2	1,269,443	12.6
2005	10,051,137	2,531,839	25.2	3,690,254	36.7	2,573,778	25.6	1,255,266	12.5
2004	10,055,315	2,553,314	25.4	3,742,180	37.2	2,512,778	25.0	1,247,043	12.4
2003	10,041,152	2,569,080	25.6	3,785,004	37.7	2,448,494	24.4	1,238,574	12.3
2002	10,015,710	2,584,310	25.8	3,820,033	38.1	2,381,204	23.8	1,230,163	12.3
2001	9,991,120	2,593,310	26.0	3,861,148	38.6	2,310,403	23.1	1,226,259	12.3
2000	9,952,450	2,596,114	26.1	3,889,337	39.1	2,245,700	22.6	1,221,299	12.3

In rebuttal testimony, Company witness Aaron Willis stated that 2023 actual credits averaged 109,754 monthly disbursements and 2024 credits are averaging 125,141 monthly disbursements. (Willis, 6 TR 2619.) The problem with Company witness Willis' methodology, however, is two-part. One, Company witness Willis' 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. Two, given the difficulties with data reliability in the RIA credit (the RIA and RSC data both being reported in Attachment 5(9) of the Company filing requirements), Staff finds it much more prudent to utilize data that is reported in the filing requirements for these credits,

as it seems to be lower and more accurate or internally audited than what the Company reports elsewhere. As for Company witness Willis' statement that "unlike the Company's Low Income Assistance Credit, the senior credit is not tracked or reconciled, and a substantial under-forecast is simply unrecoverable in the future," 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. (Willis, 6 TR 2619.) Company witness Willis' last argument in rebuttal testimony on this issue was that the Company inadvertently excluded 19,849 credits from its projection, which would actually total 124,073 monthly credit disbursements for the Company's projection. (*Id.*) Staff's arguments made in its direct testimony and in this brief are still applicable that such an increase assumes an enrollment trend line would continue linearly in future (which has not happened historically), despite the lack of population data from MDHHS to support such a trend, nor evidence from the Company that significant outreach has been performed to warrant such a significant increase in credit disbursements. Furthermore, this drastic increase in credit disbursements further reinforces the need to rely on Part III data for a reasonable projection if there is such a stark increase in unaudited credit disbursements not yet reported consistent with Part III data. Finally, under Staff's method, the trend that Company witness Willis claims will happen will be incorporated into the 3-year historical average in future years if the data ends up being accurate.

For these reasons, the Commission should approve Staff's RSC projection.

b. Staff recommends base fuel and purchase power revenue of \$1,354,105,000.

The Company projected that it would receive \$1,354,105,000 in base fuel and purchase power revenue, which is equal to Staff's projection. (Appendix C, Col c, Ln 1, 49.) Staff recommends the Commission adopt DTE's projection.

c. Staff recommends other revenue and R2 of \$115,336,000.

Staff recommends that the Commission adopt the Company's projection of \$115,336,000 in other revenue and R2. (Appendix C, Col d, Ln 1, 49.)

2. Staff recommends total operating expenses of \$4,347,057,000 for the projected test year.

Staff recommended total operating expenses of \$4,347,057,000 is \$84,984,000 less than the Company's projection of \$4,432,041,000. (Appendix C, Col n, Ln 1, 48, 49.) Staff breaks down this \$84.984 million difference, by category, and explains the difference below:

Other O&M	\$ (105,424,000)
Depreciation & Amortization	(12,839,000)
Property Tax	(693,000)
State & Local Income Tax	8,143,000
Federal Income Tax	<u>25,828,000</u>
Total Difference in Operating Expense	\$ 84,984,000

a. Staff recommends fuel and purchase power expense of \$1,354,105,000.

Staff recommends fuel and purchase power expense of \$1,354,105,000, which is equal to the Company's initially filed projection. (Appendix C, Ln 49.)

b. Staff recommends Other O&M expense of \$1,161,527,000.

Staff initially filed projected operations and maintenance expense is \$1,161,522,000, a decrease of \$105,429,000 for the Company's originally filed projected operations and maintenance expense of \$1,266,950,000 found on Exhibit A-13 Schedule C5, Line 12. In this brief, Staff has updated its case and now projects an operations and maintenance expense of \$1,161,527,000. (Appendix C, Col g, Ln 49.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Ln 21-32.

Staff recommends Other O&M expense of \$1,161,527,000, which is \$105,424,000 less than the Company initially filed projection of \$1,266,950,000. (Appendix C, Col g, Ln 1, 48 and 49.) Staff proposes the following adjustments to Other O&M Expense:

i. GENERATION

1.	Steam Power Generation	\$(19,392,000)
2.	Fuel Supply & MERC Fuel Handling	(463,000)
3.	Nuclear Power Generation	(371,000)
4.	Other Power Generation	(3,009,000)

ii. CUSTOMER SERVICE

1.	Merchant Fees	(1,231,000)
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iii.	UNCOLLECTIBLES	
1.	Uncollectibles	(9,841,000)
iv.	REGULATED MARKETING	
1.	Regulated Marketing	(292,000)
v.	CORPORATE SUPPORT	
1.	Injuries and Damages	(2,863,000)
2.	Incentive Compensation	(39,233,000)
3.	Restricted Stock	(8,960,000)
4.	Projects with Level 2 Cost Estimates	(2,386,000)
5.	Projects with Level 3 Cost Estimates	(84,000)
6.	Cost to Achieve Project Expense	(3,174,000)
vi.	PENSION AND BENEFITS	
1.	Employee Savings Plan	(7,859,000)
2.	Active Health Care	(2,334,000)
3.	Other Benefits – General Benefits	(1,344,000)
3.	Other Benefits – Admin Fees	<u>(2,588,000)</u>
Total difference in O&M Expense		\$(105,424,000)

i. Staff recommends reducing generation O&M expense by \$23,235,000.

Staff recommends reducing generation O&M expense by \$23,235,000.

(Appendix C, Col g, Ln 7-13.) This is composed of four adjustments described below.

1. Staff recommends reducing Steam Power Generation O&M expense by \$19,392,000. (Appendix C, Ln 7.)

Staff recommends reducing Steam Power Generation O&M expense by \$19,392,000. (Appendix C, Ln 7.) Staff recommends a reduction to the Company's Steam Power Generation, O&M expenses presented on the Company's Exhibit A-13 Schedule C5.1. Staff witness Kindschy testifies that these O&M expenses should be calculated using a 2023 adjusted historical test year instead of the 2022 adjusted historical test year that the Company used in its case as filed. (6 TR 5185.)

There are two reasons she testified that using an adjusted historical 2023 test year as the starting point for determining these categories of O&M expenses was more reasonable than beginning with 2022. First, DTE Electric experienced several major changes to its generation fleet during 2022. Specifically, the Company retired its St. Clair and Trenton Channel power plants as well as adding the Blue Water Energy Center, all occurring midway through 2022. By beginning with actual 2023 expenses, the normalizing adjustments for these generation fleet changes are not necessary as 2023 captures both changes for the entire 12 months without the need for adjustment. The second reason Staff determined that 2023 is a more reasonable historical year is that 2023 O&M expenses include the actual inflation experienced in 2023 without the need to be adjusted as is the case when beginning with 2022. (6 TR 5185-86.)

Staff recommends a reduction of (\$19,392,393) to Steam Power Generation O&M based on starting with a 2023 adjusted historical year. (6 TR 5185-86; S-16.7, p 1.) The Company did not file rebuttal testimony regarding Staff's proposed

reduction; therefore, Staff recommends the Commission adopt Staff's reduction to Steam Power Generation O&M expense.

2. Staff recommends reducing Fuel Supply & MERC Fuel Handling O&M expense by \$463,000. (Appendix C, Ln 9.)

Staff recommends reducing Fuel Supply & MERC Fuel Handling O&M expense by \$463,000. (Appendix C, Ln 9.) The Company presents its Fuel Supply & MERC Fuel Handling O&M expense at Exhibit A-13 Schedule C5.2. Staff witness Kindschy testified that these O&M expenses should be calculated using a 2023 adjusted historical year instead of the 2022 that the Company used in its case as filed. (6 TR 5185.) As previously noted for Steam Power Generation O&M expenses, no inflation adjustment is necessary in 2023 when beginning with an adjusted historical 2023 year to develop the projected test year. (6 TR 5186.)

Staff recommends a reduction of (\$463,140) to MERC & Fuel Supply O&M based on starting with a 2023 adjusted historical test year. (6 TR 5185-86; S-16.7, p 2.) The Company did not file rebuttal testimony regarding Staff's proposed reduction; therefore, Staff recommends the Commission adopt Staff's reduction to MERC & Fuel Supply O&M expense.

3. Staff recommends reducing Nuclear Power Generation O&M expense by \$371,000. (Appendix C, Ln 11.)

Staff recommends reducing Nuclear Power Generation O&M expense by \$371,000. (Appendix C, Ln 11.)

Staff recommends a reduction to the Company's Nuclear Power Generation O&M expense presented on the Company's Exhibit A-13 Schedule C5.3. Staff

witness Kindschy testified that these O&M expenses should be calculated using a 2023 adjusted historical test year instead of the 2022 adjusted historical test year that the Company used in its case as filed. (6 TR 5185.) As previously noted for steam power generation and MERC & Fuel Supply O&M expenses, no inflation adjustment is necessary in 2023 when beginning with an adjusted historical 2023 test year to develop the projected test year. (6 TR 5186.)

Staff recommends a reduction of (\$370,897) to Nuclear Generation O&M based on starting with a 2023 adjusted historical test year. (6 TR 5185—86; S-16.7 p 3.) The Company did not file rebuttal testimony regarding Staff's proposed reduction; therefore, Staff recommends the Commission adopt Staff's reduction to Nuclear Generation O&M expense.

4. Staff recommends reducing Other Power Generation O&M expense by \$3,009,000. (Appendix C, Ln 13.)

Staff recommends reducing Other Power Generation O&M expense by \$3,009,000. (Appendix C, Ln 13.) Staff recommends a reduction to the Company's Other Power Generation O&M expense presented on the Company's Exhibit A-13 Schedule C5.5. Staff witness Kindschy testified that these O&M expenses should be calculated using a 2023 adjusted historical test year instead of the 2022 adjusted historical test year that the Company used in its case as filed since no inflation adjustment is necessary when beginning with 2023 actual expenses. (Kindschy, 6 TR 5185.) In addition, as previously noted for steam power generation, DTE Electric experienced several changes to its generation fleet. The Company made an upward adjustment to its Other Power Generation O&M expenses for the Blue

Water Energy Center since the plant came online midway through 2022. (6 TR 1715-16.) Staff argues it is more reasonable to use actual 2023 Other Power O&M expenses as the historical test year because 2023 includes a full year of operation of BWEC without adjustment as well as actual inflation for 2023. (6 TR 5185-86.)

Staff recommends a reduction of (\$3,008,921) to Other Power Generation O&M based on starting with a 2023 adjusted historical test year. (6 TR 5185-86; Exhibit S-16.7 p. 4.) The Company did not file rebuttal testimony regarding Staff's proposed reduction; therefore, Staff recommends the Commission adopt Staff's reduction to Other Power Generation O&M expense.

ii. Staff recommends reducing Customer Service O&M expense by \$1,231,000.

Staff recommends reducing Customer Service O&M expense by \$1,231,000 for Merchant Fees O&M expense. (Appendix C, Col g, Ln 16.) Staff recommends reducing Customer Service O&M expense by \$1,231,000 for Merchant Fees O&M expense. (Appendix C, Col g, Ln 16.) In its initial filing, the Company proposed that the Commission include a \$12.29 million merchant fees O&M expense in the revenue requirement. (Bennett, 6 TR 1982.)

Staff witness Theresa McMillan-Sepkoski testified recommending a reduction of \$1,236,000 in merchant fees O&M expense; although, that amount has now changed. (McMillan-Sepkoski, 6 TR 4926.) Staff's calculation resulted in a decrease to the Company's projected merchant fees O&M expense for the projected test year and was based on updating the Company's Exhibit A-13, Schedule C5.7.1

with 2023 actual O&M costs and projecting forward to the test year. (6 TR 4928; S-7.5.) However, the Company submitted to Staff a supplemental response that updated the breakdown of fees between residential and non-residential customers for 2023. This resulted in a \$5,000 reduction to Staff's calculation.

Staff's testimony and exhibits were not disputed by the Company in rebuttal. Staff recommends that the Commission approve \$11,065,000 for the merchant fees O&M expense for the projected test year, that includes the reduction of \$1,231,000 to the Company's projected merchant fees O&M expense.

The AG recommends that the Commission disallow \$3.5 million in merchant fees O&M expense pertaining to non-residential customers use of credit cards for bill payment. (6 TR 3691.)

iii. Staff recommends reducing Uncollectibles O&M expense by \$9,841,000.

Staff recommends reducing Uncollectibles O&M expense by \$9,841,000. (Appendix C, Col g, Ln 18.) Staff recommends reducing Uncollectibles O&M expense by \$9,841,000. (Appendix C, Col g, Ln 18.) Staff witness Shannon Rueckert testified that although the Company's methodology aligns with Staff's direct write-off method, the revenue amount used is excessive. (6 TR 4991.) The expense projection is created by multiplying revenue by the bad debt loss ratio (BDLR), as shown in Exhibit A-13, Schedule C5.8. Using an excessive revenue amount results in an unreasonable uncollectible expense (UCX) projection. (*Id.*) In response to audit the Company stated that its UCX calculation uses the Total

Proposed Revenue from Exhibit A-16, Schedule F2, column c, and includes PSCR revenue not shown in the Company's exhibits. Staff witness Rueckert disagreed with using the proposed revenue. He argued that using future revenue at proposed rates leads to an iterative calculation for the Cost-of-Service study. (*Id.*) Additionally, using projected revenue at the Company's proposed rates results in an excessive UCX projection. (*Id.*) Witness Rueckert noted that it is unlikely that the Company's proposed rates will be approved without recommended adjustments. (*Id.*) Staff also believes that PSCR revenue should be excluded since it is not present in the Company's exhibits and has not been audited by Staff in this general rate case. (*Id.*) Staff recommends using the total current revenue projected by test year billing determinants at the current known rates, as shown in Exhibit A-16, Schedule F2, page 2, col b, ln 49. Projected revenue at the current known rates results in a more reasonable UCX projection that is not iterative regarding the Cost-of-Service study. (6 TR 4991.) Staff recommends a projected uncollectible expense of \$41,029,000 a downward adjustment of \$9,841,000 from the Company's request of \$50,870,000 on revised Exhibit S-14.0. (Rueckert, 6 TR 4992.)

In rebuttal Company witness Sparks disagreed with Staff's use of present revenue and exclusion of PSCR revenue. However, they acknowledged that the Commission agreed with Staff's use of present revenue rather than projected revenue. (6 TR 2382.)

iv. Staff recommends reducing Regulated Marketing O&M expense by \$292,000.

Staff, through its witness McMillan-Sepkoski, recommends reducing Regulated Marketing O&M expense by \$292,000. (Appendix C, Col g, Ln 20.) In its initial filing, the Company proposed that the Commission include a \$32,154,000 for regulated marketing O&M expense in the revenue requirement. (Bennett, 6 TR 1986.)

Staff's recommended disallowance, resulting in a decrease to the Company's projected marketing O&M expense, was made by updating the Company's Exhibit A-13, Schedule C5.9 with 2023 actual O&M costs and projecting forward to the test year. (6 TR 4926; S-7.4.) Staff's testimony and exhibits were not disputed by the Company in rebuttal. Therefore, Staff recommends that the Commission approve \$31,862,000 for the regulated marketing O&M expense for the projected test year, that includes the reduction of \$292,000 to the Company's projected merchant fees O&M expense.

v. Staff recommends reducing Corporate Support O&M expense by \$56,700,000.

Staff recommends reducing Corporate Support O&M expense by \$56,700,000. (Appendix C, Col g, Ln 22-28.) This is composed of six adjustments described below.

1. Staff recommends reducing Injuries and Damages O&M expense by \$2,863,000. (Appendix C, Ln 23.)

Staff recommends reducing Injuries and Damages O&M expense by \$2,863,000. (Appendix C, Col g, Ln 23.) The Company used the normalization

method approved in Case No. U-21297 and prior cases. Staff witness Rueckert requested the Company update its projection to include 2023. (6 TR 4992.) Updating the Company's projection to include 2023 results in an Injuries & Damages projection of \$15,577,000 a downward adjustment of \$2,863,000 from the Company's request of \$18,440,000. (6 TR 4992.)

2. Staff recommends reducing Incentive Compensation O&M expense by \$39,233,000. (Appendix C, Ln 24.)

Staff recommends reducing Incentive Compensation O&M expense by \$39,232,000. (Appendix C, Ln 24.) In its initial filing, the Company proposed that the Commission include a \$59,504,000 incentive compensation O&M expense in the revenue requirement. (Fix,⁴ 6 TR 2875; S-7.1.) However, portions of this expense should be disallowed by the Commission as compensation tied to the Company's financial metrics.

Staff witness McMillan-Sepkoski recommended disallowance is the portion of the Company's employee incentive compensation plan (EICP) expense that is tied to achieving financial metrics. (6 TR 4925.) The Company has incentive compensation programs that are, in part, based on achieving financial metrics. Staff does not dispute the overall reasonableness of employee compensation, but instead argues that there should be a distinction on who pays based on the metrics included. For example, ratepayers benefit from operational metrics that promote

⁴ Witness Fix replaced witness Cooper in this instance. Staff testimony originally cited to witness Cooper.

reliability and safety. Stockholders benefit from financial metrics based on earnings per share and operating cash flow. The Commission has long held that shareholders, not ratepayers, must pay for incentives related to increasing profits, and no party has given a reason for the Commission to reverse that stance. (6 TR 4923-4924.)

Staff's recommendation to the Commission is based on the Commission's Order in MPSC Case No. U-21297. In that case, the Commission disallowed employee incentive compensation tied to financial measures. *In re DTE Electric 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p 238. This is consistent with prior Commission orders finding that when incentive compensation plans are tied to Company earnings and cash flow, the plans largely benefit shareholders. (*Id.*) Applying the same reasoning to the instant case, Staff aligned the cost of financial performance measures within the incentive compensation plan to the group that benefits from those financial performance measures-shareholders.

The AG, through her witness Sebastian Coppola, recommends the Commission disallow \$39,232,000 of the financial metrics portion of incentive compensation and only approve 47.4% of the remaining \$20,271,000 or \$9,608,000 of the incentive compensation tied to operational metrics for a total disallowance of \$49,895,000. (Coppola, 6 TR 3706.)

ABATE, through its witness Jessica A. York, requests that the Commission disallow \$39,232,000 of incentive compensation related to financial measures and

disallow \$9,539,000 of incentive compensation related to operational measures.
(York, 6 TR 3345-46.)

3. Staff recommends reducing Restricted Stock O&M expense by \$8,960,000. (Appendix C, Ln 25.)

Staff recommends reducing Restricted Stock O&M expense by \$8,960,000.
(Appendix C, Ln 25.) Staff recommends reducing Restricted Stock O&M expense by \$8,960,000. (Appendix C, Ln 25; McMillan-Sepkoski, 6 TR 4925.) The value of the awards granted is dependent on the DTE Energy Company stock price. According to Company witness Matthew Fix, “...the expense is exclusively based on the number of shares granted at the date of grant...” (Fix, 6 TR 2888.) However, the booklet provided as Exhibit S-7.2, pages 2—3, further explains that these awards “enable [recipients] to share in the value created for shareholders,” “reward [recipients] for sustaining the Company’s profitable growth,” and “link [recipients] rewards to long-term financial results.” (S-7.2.)

As the Company’s Restricted Stock awards are tied to value created for shareholders, sustaining profitable growth, and rewarding financial results, excluding this expense would be consistent with the Commission’s long-standing position of disallowing compensation expenses related to financial metrics.

4. Staff originally recommended reducing Projects with Level 2 Cost Estimates O&M expense by \$2,386,000. (Appendix C, Ln 26), and Staff recommends reducing Projects with Level 3 Cost Estimates O&M expense by \$84,000. (Appendix C, Ln 27.) Staff has updated its recommendation and now recommends a disallowance of \$1.828 million.

The Commission should disallow \$1.828 million in O&M associated with IT investments. In direct testimony, Staff recommended a 20% disallowance of O&M expenses for IT projects with Level 2 cost estimates totaling \$2.386 million.

(Rogers, 6 TR 5112.) This is consistent with Staff's recommended 20% capital expenditure disallowance for Level 2 projects. Additionally, Staff recommended a 10% disallowance of O&M expenses for IT projects with Level 3 cost estimates totaling \$0.084 million. (Rogers, 6 TR 5117.) This is also consistent with Staff's recommended 10% capital expenditure disallowance for Level 3 projects. The sum of Staff's O&M recommended disallowances in testimony was \$2.470 million.

In rebuttal testimony, Company witness Uzenski argued that if the Commission decides to disallow 20% of expenses for IT projects with Level 2 cost estimates and 10% for IT projects with Level 3 cost estimates, then the O&M impact should be reduced by the amount not applicable to DTE Electric. She states that the \$2.470 million supports all DTE users of the assets while only about 74% pertains to DTE Electric. (Uzenski, 6 TR 1563.) Staff agrees with Company witness Uzenski. As a result, the Commission should disallow \$1.828 million in O&M expenses associated with IT investments pertaining to DTE Electric Company. Staff notes that the appendices and revenue deficiency calculation in this brief mistakenly reflect the original \$2.386 million level 2 O&M expense

adjustment and \$0.84 million level 3 O&M expense adjustment. Staff will correct the calculation in its reply brief to properly reflection the updated recommendation of a \$1.828 million level 2 & 3 O&M expense adjustment, which increases the revenue deficiency by \$558,000.

5. Staff recommends reducing Cost to Achieve Projected O&M expense by \$3,174,000. (Appendix C, Ln 28.)

Staff recommends reducing Cost to Achieve Projected O&M expense by \$3,174,000. (Appendix C, Ln 28.) The Commission should disallow \$3.174 million in Project Cost to Achieve IT O&M. (Rogers, 6 TR 5124.) Project Cost to Achieve is the O&M cost attributed to each capital investment in Company Exhibit A-24 Schedule N3. (Sharma, 6 TR 2029.) DTE projected a Project Cost to Achieve expense of \$21.369 million; however, it only supported \$18.195 through testimony and exhibits. Staff submits that all costs requested by the Company for inclusion in rates should be supported with evidence in testimony and exhibits to show they are reasonable and prudent. This remaining \$3.174 million is unaccounted for and not connected to any project or investment. It is unfair to pass such a cost onto ratepayers that is unjustified and without a purpose. (Rogers, 6 TR 5124.) The Company did not include this adjustment in its rebuttal testimony. For these reasons, the Commission should disallow \$3.174 million in Project Cost to Achieve IT O&M.

vi. Staff recommends reducing Pension and Benefits O&M expense by \$14,125,000.

Staff recommends reducing Pension and Benefits O&M expense by \$14,125,000. (Appendix C, Col g, Ln 30—34.) This is composed of four adjustments described below.

1. Staff recommends reducing Employee Savings Plan O&M expense by \$7,859,000. (Appendix C, Ln 31.)

Staff recommends reducing Employee Savings Plan O&M expense by \$7,859,000. (Appendix C, Ln 31.) Staff recommends reducing Employee Savings Plan O&M expense by \$7,859,000. (Appendix C, Col. g, Ln 31.) Company witness Fix⁵ used “the annual increase in the Company’s Employee Savings Plan costs for the years 2017 through 2020 of 7.50%.” The calculation of this rate excludes years 2021 and 2022. Company witness Fix (originally testified to by M.S. Cooper) cited an “abnormally high level of forfeitures arising from employee resignations in 2021” as reason for exclusion. (Rueckert, 6 TR 4992; Fix, 6 TR 2861.) Staff witness Rueckert contested the Company’s projection. He requested the Company’s expense for 2023 and noted that the downward trend continued. Staff maintained the position that the consistent consecutive diminishing growth trend shows that witness Fix’s reasons for excluding 2020 and 2021 from its AAGR are not valid. (6 TR 4993.) ESP expense growth continues to decline for five consecutive years.

⁵ This portion of Company witness Michael S. Cooper’s application testimony was replaced by Company witness Matthew A. Fix.

Witness Rueckert argued that consistent annual changes the Company experiences should be reflected in expense projections of its rate cases. (6 TR 4993.)

In rebuttal, Company witness Fix argued that use of the Company's 2023 ESP expense was improper because the Company capitalized an abnormally high proportion of ESP costs. (Fix (Rebuttal), 6 TR 2908.) It is Staff's position that 2023 capitalization changes should be included in forecasts to the benefit of the Ratepayer. Staff recommends an ESP expense of projection of \$29,547,000 a reduction of \$7,859,000 from the Company's projection of \$37,406,000.

2. Staff recommends reducing Active Health Care O&M expense by \$2,334,000. (Appendix C, Ln 32.)

Staff recommends reducing Active Health Care O&M expense by \$2,334,000. (Appendix C, L 3n2.) Staff recommends reducing Active Health Care O&M expense by \$2,334,000. (Appendix C, Col g, Ln 32.) 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.)⁶ 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). These increase trend factors are 5.1% in 2023, 5.0% in 2024, and 4.0% in 2024. (*Id.*) Application of these factors resulted in an expense

⁶ This portion of Company witness Michael S. Cooper's application testimony was adopted by Company witness Jerome K. Hooper.

projection of \$56,083,000. Staff witness Rueckert noted that the Company testified that its Active Healthcare expense is volatile. (6 TR 4994.) Witness Rueckert testified that contrary to witness Fix's testimony, the WTW's generalized healthcare trends are not reflective of volatility in the Company's expense history. Staff witness Rueckert requested total healthcare expense and employee headcount for 2023. (*Id.*) He used a 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. (*Id.*) The total projected cost is multiplied by the Company's expense percentage as a portion of it is capitalized. Staff's method resulted in a more reasonable Active Healthcare expense projection of \$53,749,000, a reduction of \$2,334,000 from the Company's projection of \$56,083,000. (*Id.*) In rebuttal, Company witness Hooper contested Staff's method citing that it excludes a onetime credit the Company received. (Hooper (Rebuttal), 6 TR 2948.) Staff recommends its methodology and maintains its position that the onetime credit should be to the benefit of the Ratepayer.

vii. Staff recommends reducing Other Benefits – General Benefits O&M expense by \$1,344,000. (Appendix C, Ln 33.)

Staff recommends reducing Other Benefits – General Benefits O&M expense by \$1,244,000. (Appendix C, Col g, Ln 33.) The Company projected General Benefits by escalating historic expense at the overall rate of inflation as measured by the Consumer Price Index through the end of the projected test year. Witness Rueckert noted that the Company has seen a steady decrease in General Benefits

expense for five consecutive years. (6 TR 4995.) He argued that using general inflation to increase an expense that has a -10.24% negative average annual growth rate (AAGR) creates an unreasonable projection and disincentives the Company from continuing to reduce the costs of these line items. (6 TR 4995.) Applying the Company's AAGR rate to 2023 expenses provided to Staff by the Company projects a General Benefits expense of \$1,051,000. (*Id.*) In rebuttal, Company witness Hooper argued that use of the five-year average of the annual percent change in the Company's General Benefits expense is improper as a basis for determining future escalations because the historical average is distorted by changes in the proportion of General Benefits costs capitalized. (6 TR 2953.) However, witness Rueckert's AAGR considers changes in Capitalization rates for all years as it utilizes the actual expense the Company booked.

4. Staff recommends reducing Other Benefits – Admin Fees O&M expense by \$2,588,000. (Appendix C, Ln 34.)

Staff recommends reducing Other Benefits – Admin Fees O&M expense by \$2,588,000. (Appendix C, Ln 34.) Staff recommends reducing Other Benefits – Admin Fees O&M expense by \$2,588,000. (Appendix C, Col g, Ln 34.) The Company projected Administrative Fees by escalating historic expense at the overall rate of inflation as measured by the Consumer Price Index through the end of the projected test year. (6 TR 4995.) Witness Rueckert noted Administrative Fees has seen volatility; however, the expense has decreased often in the last five years. He argued using general inflation to increase an expense that has a -5.57% negative average annual growth rate (AAGR) creates an unreasonable projection

and disincentives the Company from continuing to reduce the costs of these line items. (6 TR 4995.) Applying the Company's AAGR rate to 2023 expenses provided to Staff by the Company projects an Administrative Fees expense of \$4,708,000. (*Id.*) In rebuttal Company witness Hooper argued that Staff witness Rueckert's projected Benefit Administration Fees is based on the proportion of Benefit Administration Fees allocated to expense in 2023, which was distorted by one-time O&M reductions implemented by the Company in 2023. (6 TR 2955.) However, this argument does not dismiss the negative expense trend the Company has realized. It is Staff's position that Company actions reducing expenses should be to the benefit of the rate payer and included in future rates. Therefore, Staff recommends reducing Other Benefits – Admin Fees O&M expense by \$2,588,000.

c. Staff recommends depreciation and amortization expense of \$1,253,406,000.

In its initial filing, DTE projected that its depreciation and amortization expense would be \$1,266,245,000. Staff's depreciation expense of \$1,253,406,000 is \$12,839,000 less than the company's projection. (Appendix C, Col h, Ln 1, 48 and 49.) Staff's depreciation and amortization expense is less than the Company's because of the impact of Staff's capital expenditure disallowances on depreciation expense. See above at IV(A)(1)(b) for Staff's corresponding capital expenditure disallowances.

d. Staff recommends property tax expense of \$328,080,000.

Staff, through its witness Hecht, recommends property tax expense of \$328,080,000, which is \$693,000 less than the company's projection. (Appendix C, Col i.) In his testimony, Staff witness Hecht proposed a reduction to property tax expense as a corresponding adjustment from the capital expenditure reductions since the projected tax liability is derived from historic and projected capital expenditures. (Hecht, 6 TR 4889—90.) In the Company's rebuttal testimony, Company witness Wisniewski agreed with the methodology used by Staff to calculate the proposed property tax expense adjustment. (Wisniewski, 6 TR 2846.)

Based on the record evidence in this case, and the Company's agreement in rebuttal, Staff recommends the Commission adopt its adjustments to reduce property tax expense by \$693,000. Staff also recommends that property tax expense be updated to include the corresponding impact of any decisions made by the Commission that affect the Company's projected capital expenditures.

e. Staff recommends other tax expense of \$53,180,000.

Staff recommends the Commission adopt the Company's projected other tax expense of \$53,180,000. (Appendix C, Col j, Ln 1.)

f. Staff recommends state and local income tax expense of \$69,557,000.

Staff recommends state and local income tax expense of \$69,557,000, which is \$8,143,000 greater than the company's projection of \$61,413,000. (Appendix C, Col

k, Ln 1, 48 and 49.) Staff's state and local income tax is different than the company's due to Staff's adjustments to the Company's projected revenues and expenses.

g. Staff recommends federal income tax expense of \$133,604,000.

Staff recommends federal income tax (FIT) expense of \$133,604,000, which is \$25,828,000 greater than the company's projection of \$107,776,000. (Appendix C, Col l, Ln 1, 48 and 49.) Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference.

h. Staff recommends other utility (income)/deductions of \$6,400,000.

Staff recommends the Commission adopt the company's projected other utility (income)/deductions of \$6,400,000. (Appendix C, Col m, Ln 1.)

i. Staff recommends a total allowance for funds used during construction (AFUDC) operating income of \$55,969,000.

Staff recommends the Commission adopt the company's projected AFUDC of \$55,969,000. (Appendix C, Col p, Ln 1.)

j. Staff recommends loss on reacquired securities of \$2,244,000.

The Company projected Other Operating Income reduction of \$2,244,000 for loss on reacquired securities. Staff recommends the Commission adopt the Company's projection. (Appendix C, Col q, Ln 1.)

k. Staff recommends return on tree trim surge regulatory asset revenue requirement of \$10,133,000.

Staff recommends return on tree trim surge regulatory asset revenue requirement of \$10,133,000, which is \$8,653,000 less than the company's projection of \$18,786,000. (Appendix A, Ln 9; Appendix A1.1, Ln 6.) Staff recommends return on tree trim surge regulatory asset revenue requirement of \$10,133,000, which is \$8,653,000 less than the company's projection of \$18,786,000. (Appendix A, Ln 9; Appendix A1.1, Ln 6.) The Company used its Rate of Return on Permanent Capital of 9.2% shown on Exhibit A-14, Schedule D1. This produced a return on the Tree Trim regulatory asset of \$18,786,000 shown on Company Exhibit A-11, Schedule A1.1. Staff witness Rueckert testified that on page 280 in the Order of Case No. U-21297, the Commission found that the program "should remain as it is" and use the short-term debt rate. (Rueckert (Revised), 6 TR 4990—91; Ufolla, 5012—5013.) Consistent with the Commission's order witness Rueckert used the short-term debt rate of 4.96% presented on Exhibit S-4, Schedule D3, and supported by Staff witness Ufolla. (*Id.*) In rebuttal, Company witness Lepczyk maintained the position that future tree trim surge expenditures should be financed through permanent capital despite the Commission order otherwise. (Lepczyk, 6 TR 2565.)

l. Staff recommends return on Monroe regulatory asset revenue requirement of \$136,947,000.

Staff recommends return on Monroe regulatory asset revenue requirement of \$136,947,000, which is \$572,000 less than the Company's projection of \$137,518,000. (Appendix A, Ln 10; Appendix A1.2, Ln 4.) Staff, through its witness

Nichols recommends return on Monroe regulatory asset revenue requirement of \$136,947,000, which is \$572,000 less than the Company's projection of \$137,518,000. (Appendix A, Ln 10; Appendix A1.2, Ln 4.) Staff witness Nichols stated that Staff's Monroe regulatory asset – return on is \$572,000 less than the Company's projection because Staff applied its 6.54% projected pre-tax cost of capital in lieu of the Company's projected pre-tax cost of capital of 6.57% for the Monroe regulatory asset – return on. (Nichols, 6 TR 4935.) Both Staff and DTE's pretax weighted average cost of capital (WACC) applied to the Monroe regulatory asset are recalculated from the overall cost of capital using 9% ROE in accordance with the MPSC's U-21193 order dated July 26, 2023. (*Id.*) (A-14, Sched D1; S-4, Sched D1.) Staff recommends that the Monroe regulatory asset – return on should be recalculated based upon the cost of capital decisions made by the Commission.

VII. Cost of Service, Rate Design and Tariffs

(Citations in Section XVII:

Pung, 6 TR 4946—50; Isakson, 6 TR 4897—4901; Isakson (Rebuttal), 4904—08; Zakem, 6 TR 4166—83; 6 TR 4184—4186; Burgdorf, 6 TR 2347—49; Maroun (Revised), 6 TR 2776, 2796—97; Andrews, 6 TR 3510-3512; Willis, 6 TR 2591—94, 6 TR 2629—30; Revere, 6 TR 4960—78, 4979—81; Jester (Revised), 6 TR 3797, 3805—06, 3810—13, 3815; Gard, 6 TR 3831; Naheedy, 6 TR 4231; Bunch (Revised), 6 TR 4305—4308; Braunschweig, 6 TR 3528—29, 3548; Makhijani, 6 TR 4609—24; Krause, 6 TR 5195; Kinkhabwala, 6 TR 4555; Shah, 6 TR 4788—89; Stults, 6 TR 4271—72; Davis, 6 TR 4767—68, 4969—70; Stegall 6 TR 3290, 3296—97, 3302; Sherman 6 TR 3298-3300, 6 TR 4057—58, 4067—70; Bennett, 6 TR 1974;

Exhibits S-6; S-6, Schedule P4; S-19; A-16, Schedule F1.5;

Michigan Compiled Laws (MCL) 460.6w(3)—(4), PA 341 of 2016; MCL 460.1051, PA 235 of 2023.

In re DTE Gas Company's Application for Changes to RIA and LIA Programs, MPSC Case No. U-20917, 1/21/2021 Order.

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 12/1/2023 Order.

In re DTE Electric Company 2023 PSCR Reconciliation, MPSC Case No. U-21260.

In re Commission's Own Motion, MPSC Case No. U-18239, 11/21/2017 Order, pp 68—77.

A. The Commission should approve Staff's Annual Capacity Revenue Requirement and SRM Capacity Charge which includes a true-up mechanism.

The Company's capacity revenue requirement method is not consistent with the Commission Order in U-21297, as Staff witness Mark J. Pung testified. (6 TR 4946.) In previous cases, the Company included a Reconciliation of Net Sales Benefit Difference in its calculation of the capacity charge revenue requirement, and this is the method the Commission has approved. (*Id.*) This was the Company's method for complying with Section 6w(4) of PA 341, MCL460.6w(4), 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. (Pung, 6 TR 4947.) Staff has included a Reconciliation of Net Sales Benefit Difference in its calculation of the capacity revenue requirement as Exhibit S-6, Schedule P4. This is the same calculation the Company provided in its PSCR reconciliation, MPSC Case No. U-21260, and provided to Staff in response to Audit Request MJP-1, which Staff included in its case as Exhibit S-19. (*Id.*) *In re DTE Electric Company 2023 PSCR Reconciliation*,

MPSC Case No. U-21260. Staff recommends the Commission approve its calculation of the capacity charge revenue requirement with Reconciliation of Net Sales Benefit difference which fulfills the true-up mechanism requirement of PA 341. Staff's capacity revenue requirement is \$1,035.6 million. The Company's filed capacity revenue requirement with no true-up mechanism was \$973.7 million. (*Id.*) Staff's lower overall revenue requirement combined with the inclusion of a true-up mechanism in compliance with PA 341 results in an increase of \$61.9 million. (Pung, 6 TR 4948.)

Energy Michigan (EM) witness Alexander J. Zakem in his direct testimony recommended that the Commission remove \$260,787 worth of purchased power contract costs from the SRM calculation. (Zakem, 6 TR 4166.) He cited Section 6w(3) of PA 341 which states that projected revenues shall be calculated "net of projected fuel costs." (Zakem, 6 TR 4174.) EM witness Zakem claimed that these costs represent the difference between total costs and capacity costs for specified power purchase agreements and are not fuel costs. (Zakem, 6 TR 4173.) EM witness Zakem also proposed that, because MISO now allows a Load Serving Entity (LSE) to meet its capacity obligation by season, the payments to MISO for Planning Reserve Margin Requirement (PRMR) are by season, the payments to MISO for Zonal Resource Credits (ZRCs) are by season, that section 6w of the statute and the SRM Capacity Charge should now be applied by season. (Zakem, 6 TR 4179.) Finally, EM witness Zakem recommended that the Commission set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that

charge to the MW value of an LSE's seasonal capacity deficiency, adjusted by the number of days in the season. (Zakem, 6 TR 4185.)

In rebuttal, Company witness Shawn D. Burgdorf addressed EM's proposal to exclude Power Purchase Agreement and Company Owned Renewable costs in the amount of \$260,787 from being included as "Fuel Costs" for the "energy revenue sales net of fuel cost calculation." (Burgdorf, 6 TR 2347.) He stated that correcting the oversight would also require the same \$260,787 to be removed from Revised Exhibit A-16, Schedule F1.5, Line 5 which when performed results in the same SRM Capacity Charge of \$217.30/MW-day as originally filed by the Company. (Burgdorf, 6 TR 2348—49.)

Next, Company witness Burgdorf addressed EM's proposal to require that the SRM Capacity Charge be determined by season. (Burgdorf, 6 TR 2349.) Company witness Burgdorf claimed that calculating rates for each season simply to change the allocation of costs between capacity and energy will create unnecessary additional burden and that an annual allocation is sufficient for the SRM. (*Id.*) He stated that it will substantially increase the time required to break out the costs by season as there is currently no breakdown by season when projecting costs in the Company's PSCR Plan. Company witness Burgdorf also pointed out that performing a reconciliation or true-up of costs by season would be challenging and would require significant time to determine how to perform due to the fact that they are currently performed on a calendar year basis within the PSCR Reconciliation case. (*Id.*) The annual rate combined with the reconciliation recovers the same

costs for all four seasons, and thus seasonal rates would not be beneficial.

(Burgdorf, 6 TR 2350.)

Company witness Burgdorf also addressed EM witness Zakem's proposal to set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of deficiency. (Burgdorf, 6 TR 2347.) He argued EM's proposal is short sighted because MISO's Planning Resource Auctions (PRA's) do not ensure long-term resource adequacy because they have a term of only one planning year and that a capacity shortage situation could arise. (Burgdorf, 6 TR 2350.) He also pointed out that MCL 460.6w (PA 341) requires LSE's to demonstrate they have sufficient resources to meet their resource adequacy needs on a four-year forward basis and that the MISO Auction Clearing Prices (ACPs) for the upcoming Planning Year do not represent the cost to build new generation for a capacity deficiency. (*Id.*) Company witness Burgdorf then testified that EM's proposal would effectively negate long-term resource planning and there would be no need for capacity demonstrations because LSEs would be able to just use the one-year forward MISO PRA for all their needs. (*Id.*)

EM witness Zakem, in his rebuttal testimony, recommended that the Commission eliminate from a new SRM capacity charge any "true-up" of previous estimates as long as DTE has not applied the previous SRM Capacity Charge to any party. (Zakem (Rebuttal), 6 TR 4195.) He also reiterated his proposal to apply the SRM Capacity Charge according to the MW capacity deficiency by the customer that triggered the charge instead of in price design in a rate. (6 TR 4196.) Finally, he

recommended that the true-up be done by MW in the same way as the SRM charge is applied under his proposal. (*Id.*)

Staff recommends the Commission approve Staff's capacity charge revenue requirement and SRM capacity charge calculations. The Company's filed capacity revenue requirement method is not consistent with the Commission Order in U-21297 because it did not include a true-up mechanism as required by Section 6w(4) of PA 341. Staff's position is that PA 341 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. It is Staff's position that if the Company does not do this for any reason, it will not comply with PA 341. Concerning EM witness Zakem's recommendations, they are either unnecessarily burdensome without providing sufficient benefit or are not in compliance with PA 341. Staff agrees with the Company that the MISO seasonal Auction Clearing Price does not consider long-term resource adequacy needs nor the need for capacity demonstrations due to using only one Planning Year and should not be used to set the SRM Capacity Charge to the MW value of deficiency. Concerning the SRM true-up mechanism, Staff's position is that PA 341 does not direct the Company to true-up capacity charge payments made by specific parties during a capacity charge term, but to true-up the overall projected net revenue

amounts with actual net revenue amounts for the items outlined in PA 341, Section 6w (3)(b). For these reasons, EM's proposals should be rejected by the Commission.

B. The Commission should maintain the Company's current residential customer charge.

The Company has not proposed any changes to the \$8.50 per month residential customer charge in this case. Using the Commission approved method for calculating the residential customer charge, Staff's calculation resulted in a monthly charge of \$8.86. (6 TR 4949.) Based upon the results of the approved customer charge method, no changes are necessary to the residential customer charge. (*Id.*) No other parties to this case contended this issue. Therefore, Staff recommends the residential customer charge remain at its current level of \$8.50 per month.

C. Staff takes no issue with the Company's allocation of the distribution related Infrastructure Recovery Mechanism (IRM) revenue requirement.

The Company, through its witness Habeeb Maroun, proposes to allocate the distribution related IRM revenue requirement based upon allocation schedule 521T, which is equal to each voltage class's share of distribution related plant excluding the transmission class. (Maroun (Revised), 6 TR 2776.)

Staff takes no issue with the Company's IRM allocation method. This allocation method complies with the Commission's December 1, 2023, Order in Case No. U-21297 where the Commission directed the Company to remove any allocation of IRM costs from transmission level customers. (Pung, 6 TR 4949.) No other

parties to this case contested this issue. Therefore, Staff recommends the Commission approve the Company's IRM allocation but updated for Staff's revenue requirement, proposed rate of return and any other decisions affecting it in the Commission's final order. (*Id.*)

D. The Commission should approve a 4 CP (coincident-peak) 75/0/25 allocation for purchased power capacity costs.

The Company has allocated purchased power capacity costs using allocator 251, which is based upon 4 CP, 100% demand but excluding the R10 rate class. This allocator is developed from allocator 200B which is a 4 CP, 100% demand allocator. (Pung, 6 TR 4950.) 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. (*Id.*) Staff has proposed to allocate purchased power capacity costs based upon a 4 CP 75/0/25 in alignment with longstanding Commission practice concerning production assets. (*Id.*) Staff submits there should be some recognition of both energy use and capacity use in the allocation factor for purchased power capacity costs. (*Id.*)

In rebuttal, Company witness Maroun proposed to continue using the current allocation method for purchased power capacity using 4 CP 100-0-0 demand less R10 (allocator 251) and purchased power energy using 0-0-100 energy less R10 (allocator 111). (Maroun, 6 TR 2796—97.) Company witness Maroun argued that the ongoing use of direct demand and energy allocators for the allocation of these costs within the COSS is an appropriate reflection of cost-causation. (6 TR 2796.)

Company witness Maroun did testify, however, that if the Commission agrees with Staff that purchased power capacity costs should be allocated using the 4 CP 75/0/25 method, it would also be prudent to ensure consistency in the allocations of purchased power energy and fuel costs as well. (6 TR 2797.) Currently, purchased power fuel costs are allocated using allocator 192 (12 CP 10-0-90) and purchased power energy costs are allocated using allocator 111 (0-0-100) less R10. Company witness Maroun proposed under this scenario to switch the allocation of purchased power energy costs to allocator 192 (12 CP 10-0-90) from its current 0-0-100 energy allocation using allocator 111. (6 TR 2796—97.) This would add a 10 percent demand weighting using 12 coincident peaks to the allocation of purchased power energy. The Company did not provide the class revenue impact of this proposal.

ABATE witness Brian Andrews, in his rebuttal testimony, recommended that purchased capacity costs should continue to be allocated using the 100% Demand 4 CP allocator, specifically, DTE's allocator 251. (6 TR 3513.) ABATE witness Andrews argued that DTE's purchased capacity costs are largely related to renewable energy assets (wind, solar, and biomass) that were required for compliance with PA 295, that these costs are largely fixed costs, and that the majority of these costs are already allocated on the basis of energy. (Andrews, 6 TR 3510—12.) ABATE witness Andrews, like the Company, then proposed that if the Commission modifies the allocation of DTE's PA 295 renewable assets, it should allocate them more on the basis of demand than is currently approved and in the opposite direction of Staff's proposal. (6 TR 3512.)

Staff recommends the Commission approve Staff's proposal to allocate purchased power capacity costs using allocator 255 which is the 4 CP 75/0/25 method. (6 TR 4951.) Purchased power capacity production assets provide both energy and capacity. The Commission has long recognized the dual nature of production assets going back to 1976 in Case No. U-4771 where the Commission recognized a production allocator of 12 CP 75/0/25. (6 TR 4950.) This method is also consistent with the Commission Order in Consumers Energy Case U-21389 where the Commission ordered that purchased power capacity costs continue to be allocated using a 4 CP 75/0/25 allocator. (*Id.*) However, Staff does agree with the Company 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. In addition, Michigan's other large electricity provider, Consumers Energy Company currently allocates both purchased power energy and fuel costs using 100% energy allocators.

E. The Commission should approve Staffs proposed electric rate design.

Staff, as testified to by witness David Isakson, conducted its rate design in the same fashion as the Company, but with Staff's recommended revenue requirement and billing determinants. (Isakson, 6 TR 4897.) For all of the arguments and evidence provided by Staff in the instant case, the Commission should approve Staff's electric rate design.

F. Elimination of Rate D1.6

1. The low-income assistance (LIA) credit should be made available on all residential rate schedules.

The Company, through the testimony of its witness Aaron Willis, proposed to open the availability of the LIA credit to all residential base rates. (6 TR 2591.) This proposal would eliminate the requirement that customers seeking the LIA credit must take service on Rate D1.6, which is an inverted block rate⁷ unlike the standard residential rate D1.11. (*Id.*) The Company argues that customers receiving the LIA credit should have the option to choose from the variety of rates offered by the Company. (Willis, 6 TR 2591-2592.) Witness Isakson agreed that customers receiving the LIA credit should have the option to take service on rates other than D1.6 that may better suit them. (Isakson, 6 TR 4900.) Staff, through its witness Isakson, also pointed out that Consumers Energy Company offers a similar LIA credit that is available on all of that utility's residential rates. (*Id.*) Staff recommends that even if the Commission decides to not eliminate Rate D1.6, that the LIA credit should still be made available on all of the Company's residential rates. (6 TR 4906.) No parties disagreed with this specific part of the Company's broader proposal to eliminate Rate D1.6.

In its summary of the Company's proposal, DAAO witness Koeppel failed to mention that this portion of the broader proposal—expanding the LIA credit to all residential rates—would mean that those customers would still receive the \$40 per

⁷ An inverted block rate is one with a flat energy charge for usage below a certain amount and a higher flat energy charge for usage above that amount.

month credit on other rates. (Koeppel, 6 TR 4403.) The 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. (Isakson (Rebuttal), 6 TR 4907.)

For these reasons the Commission should approve the Company's proposal to expand the LIA credit to all residential rate schedules beyond Rate D1.6.

2. Customers on Rate D1.6 should be transitioned to other applicable rates schedules while retaining their LIA credit.

The Company proposed to transition customers currently on Rate D1.6 to the default residential Rate D1.11, and those customers with a non-transmitting meter would be transitioned to Rate D1. (Willis, 6 TR 2591.) As requested by the Commission in its previous case, The Company analyzed the impact of transitioning to Rate D1.11 on Rate D1.6 customers. (Willis, 6 TR 2592—94.) The Company found that the average bill impact was a decrease of 0.17%. (Willis, 6 TR 2592.) The Company notes that customers using more energy tend to benefit more from time-of-use (TOU) rates than flat, inverted block rates, and that the average use per month for D1.6 customers is higher than that of Rate D1.11 customers. (Willis, 6 TR 2593.) The Company also argues that when the Commission approved the transition of all residential customers to the default TOU rate that approval was based on the Company's Advanced Customer Pricing Pilot which already included

an analysis of the impact on low-income customers. (Willis, 6 TR 2629—30.) In effect this means that the Commission has already considered the impact of the default residential rate D1.11 on low-income customers and found it to be reasonable.

DAAO argued, through its witness Jackson Koeppel, that the Company's impact study of transitioning customers from D1.6 to D1.11 fell short of what the Commission requested. (6 TR 4406.) DAAO argued that the study did not include an analysis of shut-off rates, a survey of customers, nor a regression analysis. (Koeppel, 6 TR 4407-4408.) Next, DAAO witness Koeppel stated that TOU rates could be beneficial for low-income customers. (Koeppel, 6 TR 4408.) This supports Staff's recommendation, as testified to by its witness Isakson to expand access to the LIA credit to all residential rate schedules. Staff again notes here that the Commission approved Consumers Energy Company's transition for all of its residential customers, including low-income customers and those receiving the LIA, to a default TOU rate before the Company even began its transition to a default TOU rate. (Isakson, 6 TR 4900.)

The Company responded to DAAO's criticism of its impact study by arguing that DAAO did not dispute its actual results or the Company's findings. (Willis, 6 TR 2629.) In fact, DAAO is principally in favor of TOU rates. (Koeppel, 6 TR 4408.) Further, the Company stated that the data necessary to perform a study like the one requested by DAAO is not available and would be extremely resource-intensive to perform. (Willis, 6 TR 2628.) DAAO criticized the Company for not including a

regression analysis to identify any statistically significant difference in the impact of TOU rates on different customers. (Koeppel, 6 TR 4407.) In response the Company argued that its analysis included approximately 26,000 customers receiving the LIA credit and directly compared their bills on Rate D1.6 and D1.11. (Willis, 6 TR 2629.) This 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 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. DAAO argued that it is more difficult for low-income customers to shift their load to the off-peak period. (Koeppel, 4 TR 4408-4409.) However, DAAO failed to mention that if those customers do manage to shift their load but are still on an inverted block rate like D1.6, then they would not realize any bill savings for doing so. Transitioning customers from Rate D1.6 to Rate D1.11 would lower bills for more than half of those customers and provide the opportunity to lower bills for the remainder.

For these reasons the Commission should approve the Company's proposal to transition customers from Rate D1.6 to Rate D1.11 or any other residential rate for which the customer is eligible.

3. Rate D1.6 should be retired by the end of the test year.

Once all current Rate D1.6 customers are transitioned to new rate schedules while retaining their LIA credit, then Rate D1.6 will no longer be necessary. (6 TR 2591.) The Company argued that it is administratively unnecessary to retain Rate D1.6. (Willis, 6 TR 2630.)

DAAO recommended that Rate D1.6 not be eliminated because DAAO does not recommend transitioning customers to Rate D1.11. (Koepfel, 6 TR 4409.) For the reasons explained in the previous section regarding the transition of customers to Rate D1.11 and because no customers would be on rate D1.6 any longer the Commission should retire Rate D1.6 by the end of the test year.

G. Residential Electric Heating COSS and Rates

1. MNSC mischaracterized the Company's residential and commercial electric heating rates.

MNSC, through its witness Douglas B. Jester,⁸ described the Company's electric heating rates as largely interruptible, requiring separate metering, or only available for geothermal space conditioning. (Jester (Revised), 6 TR 3797.)

(Witness Jester testified for CUB, Michigan Environmental Council (MEC), Sierra

⁸ The Staff is grateful for witness Jester's revised testimony, filed August 23, 2024, in which MNSC adopted some of Staff's positions. However, Staff respectfully requests that MNSC's counsel or any other party with such a situation, be careful to highlight a major change in position that impacts the Staff later in the case with an email or phone call, as a professional courtesy. Staff and Intervenor testimony was first filed on July 26, 2024. Staff requests that the Commission emphasize the need for parties to communicate with one another about major changes to positions, as the ALJs emphasize in the instructions attached to scheduling memorandums, which encourage parties to identify and minimize issues in dispute.

Club (SC), and Natural Resources Defense Council (NRDC), collectively MNSC.) Staff showed MNSC's description to not be accurate because the Company's Rate D2 is an electric heating rate that is not interruptible, does not require separate metering, and is available for uses other than geothermal space conditioning. (Isakson, 6 TR 4908.) Rate D2 is already treated separately from other residential customers, does not differentiate rates by time-of-use, has seasonal capacity charges, and is charged a much lower power supply charge compared to other residential rates. (*Id.*) For these reasons the Commission should disregard MNSC's description of existing electric heating rates.

2. MNSC's proposed additional COSS, if approved, should also differentiate heating sources for multi-family homes.

MNSC witness Jester recommended that the Commission require the Company to produce a COSS that separates out new customer classes for residential electric heating and multi-family dwellings. (6 TR 3800.) Staff does not necessarily take issue broadly with the proposal, but pointed out that electric heating customers are already separated in the COSS and have a different rate design than other customers. (6 TR 4908.) It is unreasonable to only differentiate residential heating source for single-family but not multi-family dwellings. (6 TR 4909.) If, as witness Jester seems to imply, both heating source and the type of dwelling are major drivers of differences in the cost to serve customers then both variables should be studied under MNSC's proposal for future cost of service studies. For these reasons, if the Commission approves MNSC's recommendation

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 that the Company further separate multi-family with electric space heating customers.

3. Electric space heating rates must be cost-based.

MNSC witness David Gard recommended that the Commission require the Company to provide a “robustly time-differentiated rate structure that is available to electric heating customers.” (Gard, 6 TR 3831.) However, MNSC witness Gard did not elaborate on what a “robust” rate design means. Instead, Staff witness Isakson commented that any electric heating customer rate design must be cost-based. (6 TR 4912—13.) As Staff witness Isakson testified, 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. (Isakson, 6 TR 4912.) 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 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. (*Id.*) In short, a default (i.e. not voluntary) electric heating rate must be cost based, but that does not preclude the Company from offering an electric heating DR rate as well. For these reasons the Commission should not require the Company to provide a residential electric heating that is not based on some measure of actual costs.

H. Lighting Bill Credits

1. The Commission should reject Ann Arbor's proposed bill credit for other customers' streetlighting conversion.

AA, through its witness Cyrus Naheedy, recommended that it should receive a bill credit “equal to the monies other customers will not have to pay to convert [Ann Arbor's] streetlights.” (Naheedy, 6 TR 4231.) AA found it unfair that it will pay up front to convert to LED lighting but not receive any recognition that it has relieved other customers of those conversion costs. (*Id.*) Staff argued, through its witness Isakson, that the streetlighting conversion credit proposal recommended by Michigan Municipal Association for Utility Issues (MI-MAUI) would assuage AA's concern about fairness between customer that have already paid for their LED conversion and customers that will be converted without the need to pay for contribution in aid of construction (CIAC). (Isakson, 6 TR 4913.) The Commission has approved lighting conversion credits to address the same inequity between lighting customers for Consumers Energy Company, and MI-MAUI proposed a similar treatment for the Company, as stated by its witness Richard Bunch. (Bunch (Revised), 6 TR 4305.) Under this proposal customers that paid CIAC for lighting conversion would receive a time-limited, per-lamp credit that will be adjusted to incorporate changes in LED plant in service. (*Id.*) Finally, MI-MAUI recommended that the Commission direct the Company to file a bill credit method and initial amount in its next rate case, and to consult with Staff and intervenors to develop said credit method. (Bunch, 6 TR 4308.) For these reasons the Commission should

approve MI-MAUI's lighting convers credit proposal, which would properly credit Ann Arbor for its early adoption of LED technology.

I. Tariff Issues

1. The Commission should approve Staff's tariff corrections.

During its review of the Company's proposed tariffs Staff, through its witness Isakson, identified several errors. (Isakson, 6 TR 4899.) Staff Exhibit S-6, Schedule F8 lists those errors along with Staff's recommended corrections. No party disagreed with Staff's findings nor remedies concerning the Company's tariffs. For these reasons the Commission should approve of Staff's tariff corrections.

2. The Commission should approve Staff's low-income assistance credit (LIA) tariff language.

Staff proposed edits to the low-income assistance credit (LIA) tariff language to better reflect the current administration of the credit. Due to the uncontested nature of the proposal, Staff recommends the Commission accept Staff's proposed changes.

In Staff's direct testimony, independent of the Low-Income Assistance Credit amount and structure proposals, Staff proposed edits to the LIA tariff whether or not the Commission approves of the migration of LIA customers from rate schedule D1.6 to all residential schedules. (Braunschweig, 6 TR 3528.) The cited need for this tariff language update change is to reflect the LIA language more recently approved for other regulated utilities as well as the prudence 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. (Braunschweig, 6 TR 3529.) The *Special Low-Income Assistance (LIA) Credit* language on the currently approved rate schedule D1.6 should instead read as follows:

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.

The monthly credit for the residential Low Income Assistance Credit shall be applied as follows: Income Assistance Credit: \$(40.00) per meter per month.

If a credit balance occurs, the credit shall apply to the customer's future utility charges.

Staff's more detailed reason for the change was that the proposed language is not only more succinct in defining eligibility by utilizing RIA eligibility⁹, but also more accurately reflects enrollment practices and the 32,000 monthly cap on enrollment across all residential rate schedules. (Braunschweig, 6 TR 3530.)

NRDC/MEC witness Roger Colton proposed that a self-attestation form be provided for customers who do not automatically qualify for assistance. (Colton, 6 TR 3862). Based on Staff's understanding, a self-attestation option was already offered by the Company but not included in its tariff language. Staff adopted and

⁹ This is if the D1.6 tariff migration occurs. If it is not approved, the RIA eligibility will have to be copied into the text instead of stating "In addition to the income verification methods listed above."

expanded upon that proposal in rebuttal testimony and proposed the following language be added to both the RIA and LIA tariffs regardless of decisions made regarding rate schedule D1.6: “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.” (Braunschweig, 6 TR 3548.) Staff noted that this language is standard in other MPSC-regulated utilities’ RIA/LIA tariff languages and was most notably approved by the Commission in MPSC Case No. U-20917 for DTE Gas Company in the 1/21/2021 Order. (Braunschweig, 6 TR 3548.)

As this tariff proposal was uncontested in rebuttal testimonies, the language with the addition regarding self-attestation should be approved.

J. Microgrids

1. It is unclear if microgrids should include fossil generation.

Detroit Area Advocacy Organization’s (DAAO) witness Arjun Makhijani proposes that several microgrids analyzed by the National Renewable Energy Laboratory (NREL) should be built. (Makhijani, 6 TR 4609—24.) Furthermore, the witness’ testimony points out that at least one of these microgrids proposes diesel generation. (Makhijani, 6 TR 4611.) Staff witness Kevin Krause responds in rebuttal that it is unclear how diesel generation on a microgrid will interact with Public Act 235 of 2023, which requires an electric provider to have a portfolio of 100 percent clean energy by 2040. (Krause (Rebuttal), 6 TR 5199; MCL 460.1051.) Staff

recommends that if these microgrids are considered that they should not include fossil generation.

2. The correct tariff for outflow from a microgrid is not net metering.

DAAO witness Makhijani proposed net metering for microgrids. (6 TR 4628.) Staff witness Krause responded stating that it should not be net metering but also discussed the applicability of several other tariffs in the rate book. (6 TR 5199—5201.) The tariffs here include DG (rider 18) which is limited to 110% of onsite consumption, PURPA (rider 5) which does not allow for fossil generation, and other distributed generation (rider 14). Staff also discusses whether microgrids should be subject to the standby tariff (Rider 3). (6 TR 5200—01.) How the microgrid generates its power and under what conditions it exports are likely to determine the correct tariff for export but at the current time it is unclear. Staff recommends that the suggestion for net metering for microgrid outflow be rejected.

3. Microgrid users should be required to pay the costs of the microgrid.

Staff witness Krause supports microgrid users paying microgrid specific costs. (Krause (Rebuttal), 6 TR 5198, 5201—5202.) The increased reliability that microgrid customers should receive constitutes a different type of service that should come with a different rate. (6 TR 5202.) There is potential, should the Commission agree, that microgrids for public service institutions could be

socialized. (6 TR 5201.) Staff recommends, that with the possible exception of public service institutions, that microgrid users pay for the costs of their microgrids.

K. DTE should not move quickly from pilot to programs.

Clean Energy Organizations (CEO)¹⁰ witness Curt Volkmann stated that DTE should move quickly from pilots to programs. (6 TR 3262-3264.) Staff, through the rebuttal of witness Krause, disagreed, stating that a thorough evaluation of the pilot should be performed before moving to program status. (6 TR 5202.) The pilot process is for examining potential outcomes, and those outcomes should be examined before being put into programs where they will be repeated. Staff recommends that the accelerating the pilot to program proposal be rejected.

L. Electric Vehicles

1. The EV demand charge holiday should not be revised.

Several witnesses testified to the temporary or permanent extension of the demand charge holiday for direct current fast chargers (DCFC). Electrify America witness Jigar Shah testified that all DCFCs in service before 2028 should permanently receive rate D3. (6 TR 4787.) Walmart witness Perry testified to either allow permanent use of rate D3 or find a cost-of-service based replacement in a future rate case. (6 TR 4725.) MEIU witness Sherman requested the use of rate D3 extended until 2030. (6 TR 4098—99.) Staff witness Krause provided Staff's

¹⁰ The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar are collectively known as CEO.

position that the demand charge holiday was meant to get the market up and running and that by the time the rate expires in 2026 that will have been accomplished. (6 TR 5204—05.) Furthermore, witness Krause testified that the rate will be open to all new DCFC's on a rolling two-year basis. (6 TR 5204.)

Walmart witness Perry also claimed that the current situation with the demand charge holiday creates “uncertainty” and “instability.” (6 TR 4742.) Staff witness Krause refuted both those claims stating “[a]fter two years on Rate D3, the customer should assume they will be moved to rate D4 if their demand is more than 1,000 kW” and “[i]f their demand is less than 1,000 kW then they can remain on rate D3, and the claim of uncertainty is even more specious.” (6 TR 5205.) MEIU witness Sherman similarly claimed that demand charge inhibits the expansion of DCFC. (6 TR 4099.) Staff witness Krause responded that charging less than the cost-of-service for DCFC will result in too much fast charging. (6 TR 5206.)

For all the reasons presented in the instant brief, Staff recommends that the demand charge holiday not be revised.

2. Contribution in Aid of Construction (CIAC) should not automatically be waived for EV charging.

MEIU witness Sherman stated that distribution upgrades due to residential EV charging should be socialized. (6 TR 4095.) MNSC witness Jester said something similar. (Jester (Revised), 6 TR 3805.) Staff witness Krause responded that a waiver is acceptable within reason, but that there should be limits on that waiver and proposes what those limits should be for residential EV charging. (6 TR

5206-5207.) Staff witness Krause also suggested that interested parties could meet to discuss limits for commercial EV charging CIAC waivers. (6 TR 5207.) Staff recommends that the Commission adopt the limits for CIAC waiver of residential charging as proposed by Staff and that limits for commercial charging waivers be further investigated.

3. Cost Benefit Analysis should properly treat State and Federal Incentives.

MEIU witness Sherman discussed state and federal incentives and their treatment in the EV cost benefit analysis. (6 TR 4059-4061.) Staff responded, through its witness Krause, that state and federal incentives are external to the utility cost test because they come from outside the utility. (6 TR 5207.) Witness 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. (*Id.*) 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.

M. Savings on Community Solar should be determined by specific costs and compensation structures.

DAAO witness Yunus Kinkhabwala modeled community solar savings of 20% of the energy rate for subscribers. (6 TR 4555.) Staff witness Krause responded that no Michigan costs or current compensation amounts were used to determine whether that projected amount of savings is appropriate. (6 TR 5196.) Savings should be a result of specific costs and compensation structures and not a promise

that is made before costs and compensation structures are known. Staff recommends that community solar savings not be promised or guaranteed.

N. The Commission should require site-level cost-benefit analyses for customer inclusion in the PowerMIFleet pilot.

The Company calculates the Company's proposed fleet electrification programs will have a positive net present value (NPV) of \$5 million for "Fleet – Other DCFCs" and \$37 million for "Fleet – Other Level 2". (Bennett, 6 TR 1974.) It is unclear, however, how much of the negative NPV of \$17 million associated with "supporting functions" is associated with these two programs. Staff witness Nicholas M. Revere stated that Staff submits 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. (Revere, 6 TR 4960.) To ensure the sites selected for inclusion in the programs are appropriate (e.g., they maximize the benefit other customers), it is necessary to conduct a site-specific cost-benefit analysis (CBA) for potential participants recipients prior to their inclusion. (6 TR 4960.) An overall EV program cost-benefit analysis is not sufficient. (6 TR 4960—61.) As stated by Staff witness Revere:

The impetus behind, for example, home charger rebates, was to eliminate barriers for EV adoption mainly for residential customers. As each residential customer is so small, the potential increase in costs for any given customer has little impact on the total. Also, in an attempt to minimize range anxiety and reduce the barriers to EV adoption, it makes sense to include DCFC and other public charging in the CBA, as they are important to enable the realization of the benefits. For these reasons, it makes sense to view the benefits and

costs as a whole rather than at an individual customer basis for at least certain other programs, such as the residential rebate programs. For fleets, however, 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. [Revere, 6 TR 4960-4961.]

Staff witness Revere also stated such a site-specific CBA should include "all relevant information, such as costs to the system of the particular set up, rate benefit of incremental load, and consider such factors as expected time and duration of charging, maximum load for charging, and any other relevant factors." (6 TR 4961.)

For the above reasons, the Commission should require individual cost-benefit analyses be conducted for each customer receiving credits under the "Fleet – Other DCFCs" and "Fleet – Other Level 2" programs.

O. The Commission should consider Staff's alternative State Reliability Mechanism (SRM) calculation.

Staff witness Revere presented an alternative SRM calculation for the Commission to consider, noting since the approval of the currently used method:

Staff has become aware of several potential issues with that method. For example, 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. [Revere, 6 TR 4962.]

The alternative calculation method put forward by Staff witness Revere is consistent with Staff's proposals in the initial round of SRM cases. (*Id.*) The alternative calculation would determine the amount of the Company's production costs that are incurred to provide capacity by using the cost of new entry (CONE), or the cost to build a combustion turbine (CT), which represents the cost of pure capacity as such a plant:

is relatively expensive to run to produce energy, but relatively inexpensive to build. Therefore, it is only economically utilized to supply energy in those hours when load is at its highest. These hours are also those which are considered to set the capacity need of the utility to serve its customers. Plants other than CTs are more expensive to build and less expensive to run, making them the most cost-effective choice only if they run enough hours a year so that the total cost is lower. Therefore, the difference between the cost to build a CT and any other type of plant is the capital cost expended to produce lower energy costs. [6 TR 4963.]

This method would be applied by taking the Company's capacity-related costs, including those allocated with the production cost allocator, and applying a percentage to those costs such that the result is equivalent to CONE or another value of capacity chosen by the Commission, with the remainder of the costs being considered non-capacity. (6 TR 4964.) For the value of capacity, Staff witness Revere recommended either MISO zone 7 CONE or the cost of capacity used for

PURPA generator payments from the period most closely matching the test year.

(*Id.*)

One potential issue with this alternative is the statutorily required net market sales to be used as an offset to capacity costs. As stated by Staff witness Revere:

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.]

Staff witness Revere provided the following alternative to the current determination of this offset:

[T]he 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 Act 341 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. [6 TR 4964—65.]

The Commission has previously recognized similar principles by using net revenues from third-party sales as an offset to fixed generation costs in MPSC Case No. U-12639. *In re Commission's Own Motion*, MPSC Case No. 12639, 12/20/2001 Order, p 10.

Staff witness Revere did not calculate the alternative SRM, and instead recommended that, should the Commission be compelled by this alternative, the Commission “require the Company to file a calculation consistent with that determination in their next general rate case.” (6 TR 4965.)

P. Certain of EM witness Alexander J. Zakem’s claims regarding the State Reliability Mechanism (SRM) should be rejected.

EM witness Zakem claimed that MISO’s capacity obligation is imposed on LSEs by multiplying the auction clearing price (ACP) by the Planning Reserve Margin Requirement (PRMR) and charging that to the LSEs. (6 TR 4178.) This is incorrect. 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. (6 TR 4969.) EM witness Zakem further claimed the construct used means money is how an LSE satisfies its capacity obligation. (6 TR 4178.) As an LSE “satisfies its capacity obligation by *providing Zonal Resource Credits (ZRCs)*,” and the charge of ACP against any shortfall acts more as a penalty than a price of unacquired capacity, this is also incorrect. (*Id.*)

EM witness Zakem also claimed that the ACP is the cost of fulfilling an LSE’s capacity obligation. (6 TR 4180.) This is incorrect. As stated by Staff witness Revere, “[t]o the extent an LSE has the ZRCs to support its Planning Reserve Margin Requirement (PRMR), the cost of satisfying the requirement is the cost of obtaining those ZRCs.” (6 TR 4969.) The Company serves its customers’ (including

those AES customers whose capacity is not supplied by the AES) capacity with all of its capacity resources. (*Id.*) 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. (*Id.*)

EM witness Zakem claimed that the current capacity charge does not properly represent the cost to an LSE of satisfying its capacity obligation, and that cost is the ACP. (6 TR 4182.) This is incorrect, as discussed previously. In addition, “[t]he current capacity charge utilizes the Commission-approved method of determining the Company’s cost of providing capacity service to any customers to which it provides that service, which is based on the cost of the agreements and assets the Company so uses.” (6 TR 4969—70.) EM witness Zakem’s proposal would incorrectly calculate the charge and would not represent the actual cost of the service provided, in violation of the statute the witness claims to be following. (6 TR 4970.) This also makes EM witness Zakem’s additional claim that the proposal would not harm full-service customers (6 TR 4183) incorrect, as full-service customers would bear the difference between the charge levied and the actual cost of the service provided. (6 TR 4970.)

EM witness Zakem, throughout direct testimony, also seems to imply that it is the LSE, which is responsible for paying the capacity charge, rather than their customers. (6 TR 4970.) This is incorrect. In MPSC Case No. U-18239,¹¹ the

¹¹ See pages 68—77 of the 11/21/2017 Commission Order in U-18239, *In re Commission’s Own Motion*.

Commission determined that the capacity revenue requirement should be allocated to the classes using the 4 CP allocator, and then used to calculate a capacity rate for each schedule, which is what “would be charged to a customer’s power supply capacity billing determinants in proportion to the amount of that customer’s capacity that the Company, rather than the AES, is responsible for covering.” (6 TR 4970.) This also ignores another of the Commission’s findings in MPSC Case No. U-18239; that the capacity charge must be the tariffed rates for capacity service applied to both full-service and AES customers bas on the interpretation of the controlling statute. (6 TR 4971.)

For these reasons, EM witness Zakem’s referenced claims regarding the SRM should be rejected.

Q. EM witness Zakem’s claims regarding capacity obligations and how the Company’s generation serves its customers should be rejected.

EM witness Zakem claimed that “it has not been accurate to think that DTE’s power plants serve DTE’s customers or any other specified group of customers” since 2005, when MISO began dispatching generating plants. (6 TR 4184-4185.) Staff disagrees, at least as far as this idea would apply to cost allocation and rates charged by the Company. (6 TR 4972.) As discussed with regard to the SRM elsewhere in this brief, and as stated by Staff witness Revere:

The Company has to meet a capacity obligation at MISO by providing ZRCs, and the ZRCs it uses to do so are nearly (if not) all provided by its plants and PPAs. The costs borne by customers through rates are the costs of the PPAs and plants used to produce these ZRCs. Similarly, with the energy used by the Company’s customers, the

market construct nets out the LMP for power produced by the Company, only paying for the energy used by customers over the Company's energy supplied or requiring payment for the inverse. The costs for energy borne by customers in rates is not the LMP but for the small amount of net interchange that occurs as described; it is the cost the Company incurs either to run its plants or under its PPAs. [6 TR 4972.]

It is also the case that the Company is required to show it contracts for or owns sufficient capacity to serve its customers 4 years into the future. (6 TR 4973.) Even though MISO dispatches plants, and regardless of the apparent market for energy and capacity, "what customers pay in rates is effectively the cost of the Company's owned generation or the generation under its PPAs." (6 TR 4972.) In addition, dispatch by MISO relies on the day-ahead bids by market participants with generation (such as the Company), and those bids are necessarily based on the costs of running said generation. (*Id.*) As a result, claims that capacity and energy from generation come somehow from MISO are at best tangentially related to the costs included in the calculation of rates charged by the Company to its customers and should therefore not be relied upon by the Commission. (6 TR 4972—73.) For these reasons, EM witness Zakem's claims should be rejected.

R. Claims that EV programs should return the full value of gross margin from incremental load should be rejected.

MNSC witness Jester seems to claim the full value of gross margin from incremental load is applied to offset connections under line extension policies. (Jester (Revised), 6 TR 3815.) This is incorrect. Line extension policies generally only apply two to three years' worth of expected revenue, sometimes offset by

incremental powers supply costs, as an offset to line extension costs, including DTE's. (Revere, 6 TR 4975.) 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. (*Id.*) 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. (Jester (Revised), 6 TR 3815.)

MNSC witness Jester also testified that grid upgrade costs associated with connecting EV chargers should be socialized, as they "can then be paid out of the aggregate new revenue that will be provided by electric vehicle charging across DTE's distribution system." (Jester (Revised), 6 TR 3805.) This claim ignores the goal of these ratepayer-funded programs, which "should be to maximize the net benefit to all ratepayers as ratepayers. Eliminating or reducing the net benefit by allowing it to accrue to the benefit of EV owners alone is not supportive of this goal; it is, in fact, antagonistic to it." (Revere, 6 TR 4973—74.) No reasonable support was provided for the proposed subsidization of EV owners by other ratepayers in pursuit of the climate goals of the state. (6 TR 4974.) MNSC witness Jester also failed to note that the proposed socialization would amount to an additional cost associated with the programs, which would need to be included as such in the cost-benefit analysis of the programs. (Revere, 6 TR 4975.) For this reason, these proposals should be rejected.

MEIU witness Sherman made similar claims (6 TR 4057—58) that should also be rejected, as they are flawed in the same manner.

It is also worth noting that these proposals rely on logic similar to that often used by customers and/or their representatives seeking discounted and/or economic development rates. (Revere, 6 TR 4973.) The argument is essentially that revenue above “marginal” costs can and should be dedicated to further programs supporting addition of that load, but that would effectively claim any net benefit of that load so it does not accrue to other customers. (Revere, 6 TR 4973—74.) As discussed previously, this is inimical to the goal of maximizing the benefits to non-participating customers and undermines the reasoning behind these programs being funded by ratepayers in the first place. (*Id.*) “Marginal” rates are generally not paid by any customer, as rates are set by dividing the Company’s total allocated costs by billing determinants. (6 TR 4974.) Any customer paying such rates could claim they were “subsidizing” other customers insofar as their rates are higher than “marginal” rates would be, underlining how little weight should be given to the claim. (*Id.*) This is additional support for the rejection of these claims.

MNSC witness Jester claimed the CBA used in support of the Company’s EV programs is flawed, as it attempts to discern the portion of EV revenue associated with the Company’s programs the CBA is in support of. (Jester (Revised), 6 TR 3815.) Staff disagrees that this is a flaw. Staff considers it an appropriate feature, as “[a]scribing benefits to usage that would have occurred absent the program is inappropriate,” and it would not properly reflect the benefits the costs of the

program enable. (6 TR 4976.) For this reason, the claim (as well as the similar claim by MEIU witness Sherman (6 TR 4067—69) should be rejected.

MNSC witness Jester also implied that inclusion of net revenues from charging as a benefit to ratepayers is inappropriate, as it is a transfer payment. (6 TR 3812—13.) Staff disagrees. While it may be true in certain tests, such as the societal cost test (SCT) or total resource cost test (TRC), those revenues are appropriately considered a cost under a participant cost test (PCT) and a benefit under a utility cost test (UCT). (Revere, 6 TR 4977.) As stated by Staff witness Revere, “[t]his fact does not make the UCT or PCT not CBAs; they each just concentrate on the costs and benefits from different perspectives, and any CBA requires a perspective from which to define costs and benefits.” (*Id.*) MNSC witness Jester further implied only an SCT is a “true” CBA. (6 TR 3813-3814.) Again, Staff disagrees. As stated by Staff witness Revere:

Each type of CBA, or perspective from which they are conducted, has value in the Commission’s consideration of the programs they are examining. The UCT 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, 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 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 CBA, but not the only perspective that should matter to the Commission. In fact, using a CBA 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, internal citations omitted.]

MEIU witness Sherman stated that it is concerning that the Company's CBA does not include societal benefits of transportation electrification. (6 TR 4070.) Staff does not share this concern in the same way; while an SCT or other manner of incorporating societal benefits and costs can provide information useful in the Commission's decision-making, "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 previously and elsewhere in this brief. (6 TR 4978.) Funding what amounts to a social program (particularly when societal benefits are the justification for doing so) through utility rates affects how the burden of such funding is distributed. (*Id.*) Income taxes are both based on income directly and by generally being "progressive" (i.e. the percentage of income to which the tax is applied increases with income, with some levels of income receiving negative or zero taxation); these taxes are a main source of revenue for governments to fund social programs or public goods they provide. (*Id.*) Utility rates, on the other hand, are not currently based on income, but rather customer determinants and utility costs. (Revere, 6 TR 4978-4979.) As stated by Staff witness Revere:

As a number of witnesses in the instant case have shown, the burden of utility rates increases as income decreases. The effect of this fact is that the burden of funding such programs falls disproportionately on lower income customers, who happen to be the very customers least likely to directly benefit from the current EV programs, at least in the short term. While lower-income customers may share equally (or even receive a disproportionate share of) the benefits such programs can provide to non-participating customers, that would be the case regardless of the method used to fund them, meaning funding through utility rates is still equivalent to regressive taxation as far as the

impact to those customers is concerned. Even if rates were based on income, the resulting burden would be more regressive than if it were levied through taxation. [*Id.*]

This issue is one that should be considered by the Commission in determining the amount of funding for EV programs it appropriate to provide through utility rates. (*Id.*)

S. The Commission should accept the Company’s proposed choice EV rebate.

MNSC witness Jester testified that the discounted EV rebate for choice customers (those not taking power supply service from the Company) is not appropriate, as both types of customers have the same net revenue due to the removal of power supply costs from the equation. (6 TR 3806.) In addition to the fact that, definitionally, choice customers do not supply revenue associated with power supply rates, the issues identified with MNSC witness Jester’s definition of net revenues discussed elsewhere in this brief render the position incorrect. (Revere, 6 TR 4979.) In fact, such concerns are part of why there is currently no rebate for such customers, and the Company’s proposal is a reasonable response to these concerns; for this reason, the Company’s proposed discounted choice rebate for EV charging should be approved. (Revere, 6 TR 4979—80.)

T. Proposals and claims regarding make-ready EV charger costs and opposition to the Company’s proposed EV CIAC waiver elimination should be rejected.

MNSC witness Jester claimed Company-supplied EV rebates should be applied to utility and customer “make-ready” costs, partially because MEVI funds

cannot be used for this purpose, implying that such would not be a change in policy but a clarification of existing policy. (6 TR 3810-3811.) Electrify America witness Jigar J. Shah opposed eliminating the EV charger CIAC waiver as proposed by the Company, with the claim that doing so “undercuts DTE’s goals of expanding public charging infrastructure and reducing range anxiety.” (6 TR 4788-4789.) Staff disagrees with these claims. If 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. (6 TR 4980.) This would extend the responsibility non-participating customer have beyond what occurs under the current program, and the justifications for doing so are insufficient. (6 TR 4980-4981.) These arguments also apply to maintaining the EV charging CIAC waiver currently in place, as that has the same effect of forcing other customer to bear these make-ready costs. (6 TR 4981.) The goal of the Company’s programs should not be to expand public charging regardless of cost, but to maximize the net benefit to non-participating customers and making it more likely more expensive chargers are installed would not achieve this goal. (*Id.*) Electrify America witness Shah also claimed that not making the changes supported by the witness would be anti-competitive and lead to more expensive utility-owned chargers being installed (6 TR 4788); as these claims are unfounded, they should not be considered by the Commission. (6 TR 4981.)

For these reasons, the Company's proposed EV CIAC waiver elimination should be approved, and rebates should not be allowed to cover make-ready costs.

U. Intervenor concerns with the Company's criteria for DCFC rebates should be rejected.

Electrify America witness Rhiannon Davis opposed the Company's proposal to require 97% uptime at rebate-receiving chargers, claiming such a requirement raises anti-competitive concerns as the Company would have uptime data claimed by the witness to be confidential and competitively sensitive, giving the Company competitive advantage should they ever install their own chargers. (6 TR 4767-4768.) This 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 that are available, rather than wasted on chargers that can't charge. (6 TR 4981-4982.) Therefore, this opposition to the Company's proposal should be rejected and the proposal approved.

Electrify America witness Davis also opposed the Company's proposal to exclude "destination" DCFC chargers from qualifying for rebates, claiming that to do so would artificially limit DCFCs and that previous chargers installed by businesses partnered with Electrify America were beneficial to both parties. (6 TR 4769-4770.) As stated by Staff witness Revere, "whether rebates funded by ratepayers for DCFCs are good for those who would otherwise have to pay for them out-of-pocket and/or the companies selling chargers is not of primary concern to Staff, nor should it be to the Commission." (6 TR 4982.) The concern should be

maximizing non-participating customers net benefits, as that is the justification for ratepayer funding of the rebates in the first place, as discussed throughout this brief. (*Id.*) Nor is the characterization of the limit as “artificial” accurate; removing rebates for chargers outside of those necessary to achieve a skeleton network to reduce range anxiety and enable the benefits of home charging assists in achieving the actual goal of such rebates. (*Id.*)

EVgo Services, LLC (EVgo) witness Lindsey R. Stegall expressed EVgo’s concern that excluding destination chargers from rebates might result in a distribution of chargers that is inequitable, particularly for those who rely on public charging such as multifamily housing residents, and limit program participation. (6 TR 3290.) EVgo witness Stegall further claimed the Company’s programs “need” to serve those who are unable to charge at home, that the proposal is improperly supported, and that maximizing non-participant benefits requires driving charging infrastructure deployment. (6 TR 3295—97, 3302.) Staff disagrees. As stated by Staff witness Revere:

[L]imiting program participation to that most beneficial to other ratepayers is a feature, not a bug, of the Company’s proposal. In addition, those who rely exclusively on public DCFC charging are not producing the very benefit that is produced by the residential EV program and basically the entire reason for ratepayers funding the program in the first place, spreading out of costs through off-peak charging, and should therefore not receive rebates regardless of what other sites that do assist in providing these benefits are allowed the rebates. In essence, the claim that driving infrastructure development without concern for the benefits produced does the opposite of what the witness claims. Rather than maximizing ratepayer benefits, it dilutes them by paying for chargers that do not produce them. [6 TR 4983.]

MEIU witness Sherman also expressed concerns with the Company's proposal to make destination DCFCs no longer rebate eligible, claiming some chargers may be designated as destination when they act more as on-route chargers. (6 TR 3298-3300.) While Staff finds this concern has potential validity, it is speculative and plenty of opportunity to respond to such an issue if it actually occurs exists, and this concern does not outweigh the benefits of the proposal discussed previously. (6 TR 4983-4984.)

For all of these reasons, the Company's proposal to cease providing rebates to destination DCFCs should be approved, and arguments to the contrary rejected.

V. City of Ann Arbor's proposal to increase the income level for income-qualified home charger rebate eligibility should be rejected.

City of Ann Arbor (AA) witness Stults proposed to increase the income level at which a customer is eligible for an income-qualified home charger rebate to 300-400% of the federal poverty level from the current 200%, claiming the provision of such rebates for only those making less than \$60,000 annually is insufficient. (Stults, 6 TR 4271—72.) Staff disagrees. It would be inappropriate and against the spirit of the rebates or the idea of income qualification to extend them to those making \$100,000 annually. For this reason, the proposal should be rejected.

VIII. Distributed Generation and Demand Response

Citations in Section XVIII:

Richter, 6 TR 4830—37, 6 TR 4841; Doherty, 6 TR 5075—77; Farrell, 6 TR 2722, 6 TR 2681—82;

DTE Electric Company 2019 IRP, Case No. 20471.

In re DTE Electric Company for 2020 Demand Response (DR) Program Reconciliation, MPSC Case No. 21044;

In re DTE Electric Company for 2021 Demand Response (DR) Program Reconciliation, MPSC Case No. 21242;

Staff's Comments filed on September 27, 2024 to MPSC Case No. U-21637, p 19.)

A. The Commission should disallow the Company's request to recover capital costs for the Smart Currents program.

The Commission should not approve the Company's request, as testified to by its witness Keegan O. Farrell, to recover \$1,672,895 in capital costs for the Smart Currents program that was originally disallowed in the settlement of the 2019 IRP, Case No. U-20471. (Farrell, 6 TR 2681—82.) Staff, as testified to by its witness Roger Doherty, supported this disallowance because the Company well exceeded what it was preapproved to spend from the 2019 IRP, Case No. U-20471, and that the benefits from the increased investment were unclear and did not justify the costs. (Doherty, 6 TR 5075—76.) These expenditures were at issue in both the 2021 and the 2022 DR reconciliation cases. *In re DTE Electric Company for 2020 Demand Response (DR) Program Reconciliation*, MPSC Case No. 21044. *In re DTE Electric Company for 2021 Demand Response (DR) Program Reconciliation*, MPSC Case No. 21242. Both cases settled without including the capital costs. Staff submits that those settlements were appropriate and that these costs should not be recovered.

The Company should be required to expand its analysis of the cost-effectiveness of its DR programs to include all its DR programs as well as its interruptible rates and this analysis should be included either in the next DR reconciliation or general rate case, whichever happens first. (Doherty, 6 TR 5076—77.) The Company supported this recommendation in rebuttal, through its witness Keegan O. Farrell, but prefers to keep discussion of cost-effectiveness of DR within the DR reconciliation cases. (Farrell, 6 TR 2722.) Staff is not necessarily opposed should the three-phased regulatory framework for DR continue in its current form. However, should there be significant changes to this process, as suggested by Staff in its comments in the rate case process improvements case (Staff's September 27, 2024 Comments in Case No. U-21637, p 19), then the cost-effectiveness analysis of DR will need to be included in future rate cases.

B. GLREA's proposed critical peak rebate (CPR) pilot requires careful consideration of cost effectiveness.

Great Lakes Renewable Energy Association (GLREA), through its witness John Richter, recommended that the Commission require the Company to, in its next rate case or DR reconciliation, to propose a CPR program. (Richter, 6 TR 4841.) As described by GLREA, CPR programs provide customers a bill credit for demand reductions during a critical peak event compared to a baseline usage estimate. (Richter, 6 TR 4830—33.) The Company currently offers a dynamic peak pricing (DPP) program on Rate D1.8, where customers are charged highly time-differentiated rates along with a very high critical peak price. (Isakson, 6 TR

4904—05.) GLREA argues that CPR programs are superior to DPP programs because they offer bill credits instead of high prices during certain times, can be added to any rate schedule, and can allow critical events to be called more often. (Richter, 6 TR 4831.) Further, GLREA adds that CPR programs are advantageous to other DR programs because they do not require equipment and are not technology specific. (Richter, 6 TR 4832.) Finally, GLREA listed a number of CPR programs around the country, including one already offered in Michigan by Consumer Energy Company. (Richter, 6 TR 4834—37.)

Staff raised concerns about the effectiveness of CPR programs. (6 TR 4904-4905.) First, CPR typically produce less demand reduction per customer than DPP programs. (*Id.*) Second, CPR programs require an imputed baseline on which a demand reduction is calculated. (*Id.*) This means that CPR programs require an assumption of the load a customer *would otherwise have used* during a critical event, rather than a DPP program which charges based on actual usage and requires no assumptions per individual customer. Third, the cost of bill credits given to CPR customers is spread to all customers. (*Id.*) The Company's DPP program, Rate D1.8, is designed to be self-contained so that it does not require other customers to directly offset bill credits. Rather, Rate D1.8 shifts the excess revenue generated during critical events and on-peak periods to that rate's off-peak charge. (6 TR 4905.)

Staff witness Isakson not expressly recommend that the Commission reject GLREA's proposal. (*Id.*) Instead, due to the concerns expressed by Staff, the

Commission should carefully consider the cost-effectiveness of a CPR program if the Commission requires the Company to propose one in a following case.

C. The Company should not approve the Company's request regarding Smart Currents.

The Commission should not approve the Company's request to recover \$1,672,895 in capital costs for the Smart Currents program that was originally disallowed in the settlement of the Company's 2021 Demand Response (DR) reconciliation, MPSC Case No. U-21242. (Farrel, 6 TR 2681—82.) Staff supports this disallowance because the Company well exceeded what it was preapproved to spend from the 2019 IRP, MPSC Case No. U-20471 and because the benefits from the increased investment were unclear and did not justify the costs. (6 TR 5075-5076.) These expenditures were at issue in both the 2021 and the 2022 DR reconciliation cases. Both cases settled without including the capital costs and Staff submits that those settlements were appropriate and that these costs should not be recovered.

D. The Company should expand its analysis of cost-effectiveness.

The Company should be required to expand its analysis of the cost-effectiveness of its DR programs to include all its DR programs as well as its interruptible rates and this analysis should be included either in the next DR reconciliation or general rate case, whichever happens first. (6 TR 5076—77.) The Company supported this recommendation in rebuttal but prefers to keep discussion of cost-effectiveness of DR within the DR reconciliation cases. (6 TR 2722.) Staff is

not necessarily opposed should the three-phased regulatory framework for DR continue in its current form. However, should there be significant changes to this process, as suggested by Staff in its comments in the rate case process improvements case, then the cost-effectiveness analysis of DR will need to be included in future rate cases.

IX. Reporting Requirements and Tracking Requests

(Citations in Section IX:

Schott 6 TR 4525—26; Makhijani 6 TR 4581, 4598—99, 4626—27;
Rebuttal Armstrong 6 TR 5216-5219;

In re Commission's Own Motion, MPSC Case No. U-20757, 12/21/2023 Order, p 28.

In re Commission's Own Motion, MPSC Case No. U-20757, Staff's Interim Progress Report dated 3/17/2023, p 21, 22, 28.

In re Commission's Own Motion, MPSC Case No. U-20898, 7/27/2022 Order, pp 8, 20.)

A. The Commission should direct Staff to continue the directive from U-20757 requiring staff to combine the monthly shutoff and arrearage report and the quarterly report.

The Commission should direct Staff to continue the implementation of recommendation 2.1 from the March 2023 Staff Report in MPSC Case No. U-20757 to combine the monthly Shutoff and Arrearage report and the Quarterly report and to have this submitted on a quarterly basis. *In re Commission's Own Motion*, MPSC Case No. U-20757, Staff's Interim Progress Report dated 3/17/2023, p 21. This recommendation combines two similar reports, streamlines the reporting process, removes unnecessary data points, and standardizes variations in similar data. It

was accepted by the Commission as a part of the December 21, 2023, Commission Order in case U-20757. MPSC Case No. U-20757, 12/21/2023 Order, p 22. Starting in the first quarter of 2025, the monthly shutoff and arrearage data will still be available on a quarterly basis broken down by month and will be easily accessible on the MPSC website as it currently is. DAAO witness Justin Schott requested the monthly reporting requirements in U-20757 be reinstated and argued that “Monthly reporting is critical to track trends and differentiate seasonal energy burdens that spike after periods of extreme weather.” (6 TR 4525.) The combination of the report will continue to allow for this tracking with ongoing accessibility and less of a reporting burden on utilities.

The Commission has ordered Staff to continue to move towards zip code and census tract level data at recommendation 2.6 of its December 21, 2023, Order in MPSC Case No. U-20757. Staff is currently in discussions on how to move towards collecting shut off and arrearage data in this form, per the order. MPSC Case No. U-20757, 12/21/2023 Order, p 28.

B. The Commission should direct staff to continue the process of making shutoff and arrearage data more publicly available in an easy-to-use format.

Staff currently provides the monthly reported shutoff and arrearage data in an easily accessible format on the Commission’s website. In addition, the utilities file the reports to the MPSC Case No. U-20757 docket in PDF form. Beginning in the first quarter of 2025 with the combination of the quarterly report and the monthly shutoff and arrearage data, the data will continue to be available to the

public in the same format that is publicly available on the Commission's website.
(<https://www.michigan.gov/mpsc/regulatory/reports/other/utility-customer-data>).

Witness Schott requested the data be made available in a publicly accessible format to be downloaded in a .csv or .xlsx file. (6 TR 4526.) The data is publicly available and analyzable on the Commission's website. However, Staff is exploring whether this publicly available data can be downloaded in an accessible format.

C. The Commission should not require DTE to quantify or track non-energy benefits of affordable energy at this time.

In his direct testimony, DAAO witness Arjun Makhijani asked the Commission to include non-energy benefits of affordable energy into ratemaking and asks the Commission to conduct or commission a comprehensive study that would quantify non-energy benefits and that such a study should not delay the implementation of affordable energy. (6 TR 4626-4627.) Finally, witness Makhijani asked the Commission to devote resources to quantifying and tracking non-energy benefits experienced by those whose energy has become affordable, especially among those who now have very high energy burdens (above 15% of their income). (6 TR 4626)

Witness Makhijani described non-energy benefits as including avoided household costs of ill-health and of becoming unhoused and its attendant costs and avoided costs to society such as costs of shelter for the unhoused, added emergency room visits, and increases in taxes and health insurance premiums. (6 TR 4581.)

Quantifying and tracking non-energy benefits related to affordable energy in rate cases is complex with no accepted methodology for standardizing quantification or tracking its impact on rates, especially in a rate-setting system based on cost-of-service, which is one reason why Staff does not recommend such tracking.

There are additional reasons why witness Makhijani's recommendations are not advisable at this time. First, as witness Makhijani stated, the data may be scattered and incomplete. (6 TR 4626.) Without clear understanding of what data is needed or available outside of the witness's vague statements, it would be nearly impossible for the Commission to analyze the non-energy benefits of affordable energy. Secondly, there is no standard methodology for measuring non-energy benefits within the rate-making process. Third, it is unclear how quantifying and tracking non-energy benefits could inform or influence ratemaking outside of simply bolstering an argument that energy affordability has a positive impact on customers, which DAAO witness Makhijani's testimony blanketly stated. (6 TR 5216.) For example, Makhijani suggested that since non-energy benefits are accepted in energy efficiency regulatory proceedings, it could be used in rate making proceedings.

However, in Michigan while societal costs tests have been provided by utilities in energy waste reduction plans, they are used as a reference given the weight deemed appropriate for such a reference. In addition, the Commission has provided guidance for certain types of projects on societal costs tests of which non-energy benefits may be considered a subset, as a part of benefit cost analysis in its

July 27, 2022 Order in MPSC Case No. U-20898. In addressing Distributed Energy Resources (DERs) the Commission directed that companies present as part of their benefit cost analysis (BCA) a proposal including both a utility cost test (UCT) and societal cost test (SCT) “to be used in multiple types of dockets including pilot proposals, distribution planning, and rate cases.” (U-20898, 7/27/2022 Order, pp 8, 20.) The Commission specified that this be used for DERS and more specifically in pilots.

Witnesses are free to argue for the value of societal benefits, but there is no formalized process to require utilities to track such benefits, which are not endogenous to the ratemaking process. Finally, it is questionable as to what weight, if any, the Commission is required to or may legally give to exogenous, non-energy benefits in its decision making in rate case proceedings.

The inherent complexity and uncertainty of these undefined benefits, if they could be considered, could lead to variable and subjective estimates which are not conducive to systematically informing the rate setting process. (6 TR 5217—19.)

Further, witness Makhijani’s testimony confirms that utility rates may not be the only or best option for factoring in and remedying the impacts of non-energy benefits. He stated that “other approaches may be more equitable, such as progressive income taxes, or taxing the corporations that would benefit most, such as health insurance companies and hospitals....” He suggested that some benefits would be that hospitals “would have fewer uncompensated emergency room visits,

or hedge funds that own large numbers of rental units which would recover rent more regularly and have lower turnover of tenants.” (Makhijani, 6 TR 4597—98.)

For all of the above reasons, the Staff submits that the Commission should not require DTE to quantify and track non-energy benefits of affordability at this time.

X. IRM

(Citations in Section X:

Evans, 6 TR 5231—37; Foley, 2 TR 120—121; Dauphinais, 6 TR 3381; Alvarez, 6 TR 3946; Stephens, 6 TR 3988—89.

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 12/1/2023 Order.)

Staff, as testified to by its witness Nicholas M. Evans, submits that it is preferable to pause the IRM than for it to continue without a break in a more inefficient manner. (Evans, 6 TR 5236—37.) By way of background, in Case No. U-21297, the Company proposed an infrastructure recovery mechanism (IRM) that would be in place for three years and include five distribution capital programs:

- 1) Conversions;
- 2) Subtransmission Redesign and Rebuild;
- 3) Breaker Replacement;
- 4) Underground Residential Distribution (URD) Replacement; and
- 5) 4.8 kV Circuit Automation.

The Company also proposed that two stakeholder processes, the IRM Planning Process and the IRM Reconciliation Process, be part of the IRM. (Evans, 6 TR 5233.)

In its December 1, 2023, order in Case No. U-21297, the Commission approved the Company's proposed IRM with several modifications. (For the purposes of this brief, only the modifications that are relevant to Staff's recommendations will be described.) As Staff witness Evans testified in this case, the Commission specified that:

The Company shall submit its annual IRM Investment Plan no later than four months prior to the start of each IRM Plan Year, and the Plan must be submitted to all intervening parties in the Company's most recently filed general rate case. The Company shall schedule and provide a forum, no later than two months before the start of the IRM plan year, for Staff and intervening parties to ask questions or raise concerns about the plan. Only Year 1 (December 1, 2023- December 31, 2024) and Year 2 (January 1, 2025- December 31, 2025) of the IRM were approved. This means that absent an extension granted by the Commission, the current IRM will expire at the end of 2025. [Evans, 6 TR 5233.]

The Company is asking for four modifications to the current IRM in this case:

1. Extend the IRM through calendar years 2026 and 2027.
2. Starting in 2026, the Pole and Pole Top Maintenance and Modernization (PTMM) program should be authorized for IRM treatment.
3. Starting in 2026, the scope of the automation program be modified from "4.8 kV Circuit Automation" to "Distribution Automation."
4. Include \$434,100,000 in additional capital expenditures to the IRM for 2025.

This amount is spread across four programs:

- a) Distribution Automation- an additional \$125.6 million;
- b) PTMM - \$121 million;
- c) 4.8 kV Hardening - \$125 million; and
- d) Frequent Outage Management (CEMI) - \$62.5 million.

Staff only supports (3) modifying the scope of *4.8 kV Circuit Automation* to *Distribution Automation* after the conclusion of IRM Plan Year 2. (Evans, 6 TR 5233-5234.) Staff does not support the other proposals. (6 TR 5234—5235.) As the Commission stated on page 289 of its December 1, 2023, Order in the Company's last electric rate case, MPSC Case No. U-21297:

[T]he Commission finds that approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM.

Staff submits that the same logic is applicable in this case. Staff does not want to have the Company locked into spending specific amounts in those IRM programs for all of 2026 and 2027, and further increase the IRM spending in 2025, when the U-21305 audit report, authored by the Liberty Consulting Group, has just been completed, and the Commission may issue an order in Case No. U-21400 regarding financial incentives and disincentives.

Liberty report's recommendations could cause DTE Electric to change spending amounts and programs included in the IRM. (Evans, 6 TR 5235.) Staff's position is that it is far better to have DTE Electric review the audit report and then make adjustments where appropriate to potential 2026 IRM spending and

programs, rather than risk being locked into inefficient spending for 2026. (6 TR 5235—36.)

The Company, as testified to by its witness Foley, has concerns with not extending the IRM in this case, as this could cause a stopping and restarting of the IRM. The Company believes this would lead to inefficiencies and reduce the ability to improve upon the process through stakeholder feedback. (Foley, 2 TR 120—121.)

Staff does not have any concerns with a gap occurring in the IRM. (Evans, 6 TR 5236—37.) 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 MPSC Case No. U-21400 on financial incentives and disincentives. (6 TR 5237.)

Other parties did not support expanding the IRM. James Dauphinais, testifying for ABATE, recommended rejecting most of the Company's proposal and stated that the Commission should only permit DTE to add Year 3 to its distribution IRM and only include the Conversion, Subtransmission Redesign and Rebuild, Breaker Replacement and URD Replacement programs, for a total investment amount for Year 3 of \$275.0 million. (Dauphinais, 6 TR 3381.)

AG-MN witness Paul Alvarez opposed rider cost recovery. He recommended that the Commission reject DTE's request to extend and expand rider IRM. (Alvarez, 6 TR 3946.)

AG-MN witness Dennis Stephens recommended that the Commission not include spending on certain programs in a 2026 and 2027 IRM. These programs are Conversion, PTMM, Subtransmission Redesign and Rebuild, Distribution Automation, and Breaker & URD Replacement. (Stephens, 6 TR 3988—89.)

Witness Perry, testifying on behalf of Wal-Mart, recommended that if the Commission approves extending the IRM, it should also require the Company to file a base rate case at the earliest possible date when the assets can be included in the Company's test year. Additionally, she recommended the Commission deny recovery of any costs exceeding what was approved in the Company's last rate case for IRM plan years 2024 and 2025 and require the Company to recover those incremental costs through base rates. Finally, if the Commission extends the IRM beyond 2025, she recommended it should evaluate whether increasing the scope to include ever-increasing costs through a rider is necessary for ensuring reliability, or if such costs should be recovered through base rates as historically done. (Perry, 6 TR 4740.)

The Company disagrees with Staff's position. Specifically, the Company does not believe that extending the IRM would result in it being locked into specific spending amounts. Instead, adjustments to 2026 and/or 2027 IRM authorization could be made in future general rate cases, even if IRM authorization for those years is granted in the current case. (2 TR 154.) Additionally, the Company has concerns about how a lapse in the IRM would be accommodated, arguing that it would lead to inefficiencies in the process. (2 TR 154—55.) In his rebuttal

testimony, Company witness Foley proposes that if the Commission does not find it appropriate to approve a two-year extension at the proposed investment levels, at a minimum the Commission should approve a one-year extension at the investment levels previously authorized for 2025, which is also IRM Year 2. (2 TR 155.)

After reviewing intervenors' direct testimony and the Company's rebuttal, Staff maintains its original position put forth by Staff witness Evans in his direct testimony regarding DTE Electric's infrastructure recovery mechanism. Specifically: 1) Staff supports modifying the scope of "4.8 kV Circuit Automation" to "Distribution Automation" after the conclusion of IRM Plan Year 2; 2) Staff does not support extending the IRM through calendar years 2026 and 2027; and 3) for 2025, Staff does not support increasing the distribution automation investment from \$24.4 million to \$150 million for inclusion in the IRM. Also for 2025, Staff does not support adding \$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.

XI. Staff's Other Issues¹²

A. Staff agrees in part with the Company's proposal for outage credits.

(Citations in Section XI.A.:

Evans, 6 TR 5229-5231; Stults, 6 TR 4259; Koeppel, 6 TR 4397; Jester (Revised), 6 TR 3793; Watts, 6 TR 4674; Foley (Rebuttal), 2 TR 148;

¹² Citations for Section XI. are under each lettered subsection.

Service Quality and Reliability Standards for Electric Distribution Rules
460.744—460.746.)

The Company is proposing that billing credits paid for outages that exceed the duration limits in service quality rules R 460.744 and R 460.745 should be recoverable from ratepayers when the outage was caused by the transmission operator, another utility, public interference, or animal interference. The Staff agrees in part and disagrees in part with the Company's proposal, as further explained below.

The Company's position regarding credits paid to customers for exceedance of the outage frequency limit in service quality rule R 460.746 is that a portion of the total credits provided to ratepayers as a whole under this rule should be recoverable, and this portion would correspond to outages caused by the transmission operator, another utility, public interference, animal interference, ice, lightning, wind, or other weather. The Company proposes to recover the outage credit costs by deferring the costs related to credits eligible for recovery, starting after an order in the instant case. The deferred amounts would be reviewed for reasonableness and prudence in the next general electric rate case, and once the deferred amounts are approved by the Commission, the Company can begin amortizing and recovering them. This proposed recovery treatment is very similar to what the Company proposed in Case No. U-20836. (Evans, 6 TR 5229-5230.)

Staff, as supported by the testimony of its witness Evans, does not agree with all of this proposal and submits 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. (Evans, 6 TR 5230.) 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. (*Id.*) 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. (*Id.*)

The Company offered to spend more time with Staff to design a methodology for the recovery of repetitive outage credits, and Staff is open to collaborating with the Company and other intervenors after the conclusion of this rate case on finalizing the methodology for the recovery of these credits, if necessary. (Evans, 6 TR 5231.)

Staff opposes recovery of long-duration outage credits for outages caused by public interference and animal interference because it is Staff's position that the Company should recover from ratepayers only those outage credits that are paid out due to outages that are outside the control of the Company to resolve. An outage caused by the transmission system operator, or another utility clearly falls within this category. However, under Staff's position, 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. (Evans, 6 TR 5231-32.)

Staff opposes recovery of repetitive outage credits for outages caused by animal interference, ice, lightning, wind, and other weather because Staff's position is that the Company recover from ratepayers only those outage credits that are paid out due to outages that are completely outside the control of the Company to prevent. An outage caused by the transmission system operator, another utility, or public interference clearly falls within this category. However, under Staff's position, credits paid out due to events such as an animal damaging equipment or a storm could 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.)

Numerous other parties also opposed recovery of outage credits to varying degrees. City of Ann Arbor witness Stults recommended that the Commission deny the Company's outage credit proposal. (Stults, 6 TR 4259.) MNSC witness Jester stated that the Commission should reject the proposal. Jester stated, however, that DTE Electric should be allowed to recover bill credits due to outages attributable to a transmission operator or other utility since it must be fixed by that party. Although he points out that the proper public policy would be for the Company to recover the cost from the responsible party. (Jester (Revised), 6 TR 3793.) Toyia Watts, testifying on behalf of DAAO, recommended the Commission reject the proposal. (Watts, 6 TR 4674.) DAAO witness Koeppel recommended that the

Commission reject DTE's proposal for deferred accounting treatment of outage credits and reject the Company's proposed system to partially recover its outage credits in the specific instances it identifies such as weather and animal interference. (6 TR 4397.) GLREA witness Richter recommended the Commission reject the proposal and stick to the limited list of outage causes that warrant recovery, enumerated in the November 18, 2022, Order in Case No. U-20836. The Commission should not allow the Company to expand this list of causes to include "weather". (6 TR 4862.)

In his rebuttal testimony, Company witness Foley stated:

The Company maintains its original proposal for outage credit recovery, however it believes that the recommendation put forth by Staff Witness Evans is reasonable. [Foley (Rebuttal), 2 TR 148.]

After reviewing intervenors' direct testimony and the Company's rebuttal, Staff maintains its original position put forth by Staff witness Evans in his direct testimony regarding recovery of outage credits: 1) Staff agrees with deferring the costs related to credits eligible for recovery; 2) For outage credits paid for outages that exceed the duration limit, only those outages caused by a transmission operator or other utility should be recovered from ratepayers; and 3) For outage credits paid to customers for exceedance of the outage frequency limit, the recoverable portion of the total credit amount provided to ratepayers as a whole should correspond to outages caused by the transmission operator, another utility, or public interference.

B. Commission should adopt Staff's recommendations regarding enhanced Benefit to Cost Analysis (BCA) and improved alignment between distribution grid plan and rate case filings.

(Citations in Section XI.B:

Kryscynski, 3 TR 323—324, 441-442; Deol Revised, 6 TR 1195-1196; Becker, 6 TR 5036—38, 5040-5041; Stephens 6 TR 4012-4015; Volkman, 6 TR 3252-3254;

Exhibits A-23, Schedule M13, S-20.0;

In re Commission's Own Motion, MPSC Case No. 20147, 4/12/2028 Order;

Staff's Comments on DTE Electric Company's DGP filed on March 15, 2024, to MPSC Case No. U-20147.)

The Commission should adopt both of Staff's recommendations regarding BCA and alignment between distribution grid plans (DGP) and rate case filings as reasonable to enhance its analysis used to support decisions made and improve transparency on investment plans as it works to improve reliability and safety of the electric distribution system.

Company witness Satvir S. Deol, in his revised testimony, described the BCA completed for the Appoline underground pilot project and comparison to pole top maintenance and modernization (PTMM) and overhead rebuild alternatives in his direct testimony. (Deol (Revised), 5 TR 1195-1196.) The BCA with calculated benefit-to-cost ratios (BCR) is provided in Exhibit A-23 Schedule M13. Although Staff appreciates the BCA efforts and sharing of the results, concerns were expressed with the incompleteness of the BCA and failure to consider true alternatives in the presented analysis. Staff witness Becker testified to concerns with the fact that the PTMM alternative would not completely make all circuits

13.2 kV capable, leaving the PTMM alternative “unfinished” compared to the overhead-to-underground work with no consideration to the fact that further work is likely needed for PTMM circuits in the analysis. (Becker, 6 TR 5036—38.) Staff recommends the Commission order the Company 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. (Becker, 6 TR 5041.) AG-MN witness Dennis Stephens and CEO witness Curt Volkmann also discussed concerns with the PTMM BCA presented by the company. (Stephens 6 TR 4012—4015; Volkman, 6 TR 3252-3254.) No rebuttal testimony was filed in response to Staff’s BCA recommendation.

Company witness Allen Kryscynski described the role and approach of the DGP and stated that the investments in the present case are consistent with the long-term vision laid out in the 2023 DGP which was filed approximately six-months prior to the present case. (Kryscynski, 3 TR 323—324.) Staff issued discovery to compare the spend in the present case with the 2023 DGP. The Company’s response in STDE-14.16 (S-20.0)¹³ demonstrates an increase in spend of over \$335 million more in 2025 projected spending across several categories in the present case when compared to the DGP amounts. The increases are within the emergent replacements; customer connection, relocations and other; tree trimming; preventative maintenance; infrastructure resilience and hardening; infrastructure

¹³ The Company issued a revised response to STDE-14.16-01 that did not impact Staff’s position.

redesign and modernization; and technology and automation spend categories. (6 TR 5040.) The discovery response explains increased expenditures are attributed to incorporating recent years into the 5-year average; inflation adjustments; errors in spend amounts; and increases in investments under frequent outage customers experiencing multiple interruptions (CEMI), 4.8 kV hardening, and City of Detroit infrastructure (CODI) investments. (*Id.*) Staff recommends the Commission order the Company to improve upon aligning spending plans between the DGP and rate case filings and instruct the Company to communicate decisions to increase or decrease spending after a DGP is filed. (6 TR 5041.) Further, Staff suggests an annual update approach mentioned in Staff's comments on DTE Electric Company's DGP filed on March 15, 2024 to MPSC Case No. U-20147 to serve as a platform to communicate changes in projected spend after a distribution plan is filed. (Becker, 6 TR 5041.) These comments were in response to the Commission's October 24, 2023 Order requesting comments on DTE Electric Company's DGP filing.

In rebuttal, Company witness Kryscynski generally supported Staff's recommendation to improve the alignment between the DGP and rate case filings. Witness Kryscynski further explained the basis for the discrepancies in emergent replacements due to updated calculations, tree trimming due to a strategic update that occurred post DGP filing to complete the surge by 2025, and infrastructure resilience and hardening, due to accelerated 4.8 kV hardening to target completion by 2026 and CEMI funding continuation. (3 TR 441—442.) Witness Kryscynski stated the company is willing to work with Staff to communicate spend changes and

is willing to collaborate with Staff and develop a process, structure, and requirement of proposed annual updates to investment plans in the DGP. (3 TR 443.)

The Commission should adopt both of Staff's recommendations regarding BCA and alignment between distribution grid plans (DGP) and rate case filings, as reasonable to enhance the Commission's decision-making processes and improve openness surrounding investment plans.

C. Staff recommends that the Company be required to provide status and expenditure updates in future rate cases for the Company's proposed capital expenditures totaling \$50 million for 2022-2025 on Error Free Communications (EFC) and Outage Map projects.

(Citations in Section XI.C.: Klocke, 6 TR 5101-04; Hatsios, 6 TR 30-32, 68-73 ;

Exhibits A-24 Schedule N7; S-18.1; S-18.2; S-18.3)

In its last (2023) general rate case No. U-21297, the Company was allowed to recover \$29.7 million for the years 2021-2024 for capital expenditures for EFC and Outage Map projects and is proposing to spend a total of \$50 million¹⁴ for 2022-2025 on these projects. *In re DTE Electric 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order. For EFC Core systems \$5.2 million in capital would be spent for the 2023-2024 bridge years and \$0.6 million for testing in 2025. For the Customer-Facing systems \$11.9 million in capital would be spent for the 2023-2024 bridge

¹⁴ This excludes \$2.4 million requested and approved in U-21297 for 2021.

years. As Company witness Hatsios testified, these expenditures are to improve power restoration accuracy and timeliness, which previously a customer's status was based on job status and thus could range from 80% to 94% on storm days and with the EFC program customer status is now reaching a 99% accuracy rate. He testified that a major driver of customer dissatisfaction was inability to provide an accurate restoration estimate. Improvements have been reached, with for example, catastrophic storm first estimate accuracy rising from 31% in 2022 to 70% in 2024. This has also led to improvements in the time after a storm has cleared for delivering estimates of power restoration, from 24-36 hours down to 10 hours for catastrophic storms and from 16-24 hours down to 5.5 hours for non-catastrophic storms.

Staff finds that these are worthy projects with value to customers and is not recommending any monetary adjustments to the programs. Staff would like the Company to focus on established metrics and improvements in power restoration accuracy and timeliness, first estimate accuracy, and outage notification delivery. With respect to improvements in Customer-Facing Systems, notably Systems Enhancement Workstream, Customer Notifications Workstream, Customer Channels Workstream, and Police and Fire Website Staff recommends that the Commission require the Company to demonstrate the results of any investments in these in future rate cases.

Staff further recommends that the Commission require the Company provide detailed continuous status updates of any continuous improvements as well as

failures in the EFC system and its components, preferably in the form of biannual meetings with Staff. Staff also recommends that the Commission require detailed updates in future rate cases.

D. Staff recommends the Commission reject the DAAO's proposed additional research and study of energy affordability.

(Citations in Section XI, D.: Braunschweig, 6 TR 3545)

In their respective direct testimonies, intervenors proposed additional research and studies into energy affordability, including DAAO witness Schott's recommendation for the Commission's low-income workgroups to research and submit affordability structures to the Commission 90 to 120 days after the final order in the instant case. (Braunschweig, 6 TR 3545.) Staff opposed this proposal, however, by stating that the work is already underway in the AAA subcommittee by development of utility PIPP reports and that the deadline for the reports and analysis will likely coincide with Staff's proposed timeline mentioned in the direct testimony of witness Braunschweig. (*Id.*) For these reasons and to reduce redundant analyses, Staff recommends the Commission reject DAAO witness Schott's research proposal.

E. The Commission should not reply on CEO's regression analysis of reliability.

(Citations in Section XI.E.

Tan, 6 TR 3274-3280.)

CEO, through its witness Boratha Tan, provided a regression analysis that attempted to show a correlation between demographic variables and reliability in the Company's service territory. (Tan, 6 TR 3277—80.) The Company, CEO, and Staff have met and continue to meet and work together to develop a regression analysis for the same purpose, as directed by the Commission in the Company's previous general rate case. (6 TR 3274—75.) Because regression analysis efforts are already on-going Staff recommends that the Commission only rely on that collaborative analysis when it is completed for its decision making and not the one presented by CEO in the instant case.

**F. LIA Credit Increase and Energy Assistance Program Changes:
The Commission should reject any changes to the structure or
amount of utility-based energy assistance.**

(Citations in Section XI.F.: Sparks 6 TR 2368, 2373; Sparks (Rebuttal) 2385—91; Braunschweig 6 TR 2525—3528, 3541—48; Koeppel, 4393, 4432; Makhijani 6 TR 4598, 4626; Schott, 4506—07, 4598.; Kinkhabwala 6 TR 4516, 4680, 4547—48; Colton, 6 TR 3861, 3894—95;

MCL 460.10(t)(6)(b); MCL 460.11(1)—(2);

In re DTE Electric 2022 Rate Case, Case No. U-20836, 11/18/2022 Order;

In re Commission's Own Motion, MPSC Case No. U-20757, 12/21/2023 Order.

In re DTE Electric 2014 Rate Case, MPSC Case No. U-17767, 12/11/2015 Order.)

The Company, DAAO, and NRDC/MEC made proposals to increase the amount of the Low-Income Assistance Credit (LIA), approve percentage of income payment plans (PIPP), restructure energy assistance, and close the energy affordability gap. Because the Commission's Affordability, Alignment, and

Assistance Subcommittee in the Energy Affordability and Accessibility

Collaborative is currently tasked with analyzing the current energy assistance offerings and making recommendations around the best fulfillment of the statute MCL 460.11(2), Staff recommends the Commission reject any changes to the amount or structure of utility-based energy assistance, as detailed below.

Company witness Sparks summarized the Company's current energy assistance offerings, including stating the intent to present the Company's PIPP¹⁵ data to the Commission's Energy Affordability and Accessibility Collaborative (EAAC) and its proposal to increase the LIA from \$40 per month to \$50 per month. (6 TR 2368, 2373.) In support, witness Sparks stated that at the inception of the LIA credit in MPSC Case No. U-17767, the credit equaled approximately 43% of an eligible customer's bill, but only equals approximately 34% of an eligible customer's bill under the currently approved rates as of MPSC Case No. U-21297. (6 TR 2373.) *In re DTE Electric 2014 Rate Case*, MPSC Case No. U-17767, 12/11/2015 Order.

Therefore, witness Sparks proposed increasing the credit to \$50 per month to have the credit cover a similar proportion of a customer's bill as when the credit was originally approved. (*Id.*)

Staff witness Braunschweig referring to MPSC Case Nos. U-20836 and U-20757, 11/18/2022 and 12/21/2023 Orders, respectively, recommended the Commission reject the Company's proposal. In MPSC Case No. U-20836, the

¹⁵ The Company's percentage of income payment plan pilot (PIPP) is named the Payment Stability Plan (PSP).

Commission charged the EAAC with reviewing a DTE report detailing the LIA enrollment and to discuss the LIA enrollment assignment and cap, following with a report and recommendations to the Commission. However, in MPSC Case No. U-20757, the Commission updated its intention for the LIA analysis by charging the EAAC's Affordability, Alignment, and Assistance subcommittee (AAA) with analyzing the utility PIPP pilots, Michigan Energy Assistance Program (MEAP) offerings, and the Commission's fulfillment of MCL 460.11(2). MCL 460.11(2) establishes a low-income rate for an "eligible low-income customer" as defined by criteria established at MCL 460.10(t)(6)(b). Currently, the statute only provides for low-income credits or rates for customers who meet certain eligibility requirements (150% of FPL or receipt of SER, Food Stamps or Medicaid) as defined in MCL 460.10(t)(6)(b). MCL 460.11(2) establishes a low-income rate for an "eligible low-income customer" as defined by criteria established at MCL 460.10(t)(6)(b). The LIA is a step towards fulfillment of this legislative directive. (6 TR 3525.) Therefore, based on the referenced Commission orders and statute, Staff witness Braunschweig asserted that Company witness Sparks' testimony failed to provide the comprehensive analysis and diverse collaboration the Commission is seeking to inform utility energy assistance changes. (6 TR 3525—26.) Staff noted that this collaborative work is already underway in the EAAC workgroups and that it should lead to the most informed positions and decisions on this matter. (6 TR 3526.) Staff also notes that any apparent lack of response to Company witness Sparks' claimed effectiveness and best use-case of the credits is not an indication of agreement with

the claims because that analysis is being addressed elsewhere at Commission direction. (*Id.*) Staff clarifies that while the PIPP, LIA, and RIA analysis has not concluded, Staff provided a copy of the most recent AAA subcommittee meeting PowerPoint presentation to verify that analysis is underway, which includes cost estimates and potential reform options similar to witness Sparks' proposal. (6 TR 3526—27.) Staff witness Braunschweig further clarified that DTE representatives participate in the subcommittee and that the 10-month date for a Commission decision could come near the targeted Staff response to the LIA report in the first quarter of 2025. (6 TR 3527—28.) Staff's recommendation, therefore, is to not approve any changes to the structure of the credits and allow proposed recommendations to disseminate from the EAAC until it completes its relevant Commission directives. (6 TR 3528.) Staff did, however, note that the LIA credit amount outlined in the tariff should reflect the Commission's decision. (*Id.*)

In the Company's rebuttal testimony, Company witness Sparks disagreed with Staff witness Braunschweig's rejection of the LIA credit increase proposal. (Sparks (Rebuttal), 6 TR 2385.) Company witness Sparks argued that the credit increase only maintained alignment with the original percentage of bill relief and does not change outcomes of the Commission's Energy Affordability and Accessibility Collaborative workgroups. (*Id.*) Company witness Sparks' assumption about EAAC outcomes ignores the nuance that contributing more money to a program that partially subsidizes the Michigan Energy Assistance Program 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. Company witness Sparks recognizes the potential for such an issue when stating “it will take additional time for the Commission to rule and provide the method of implementing such recommendations and further time to retire and implement a new method of integrating the LIA credit funding” while not stating explicitly that retiring LIA credit funding could take longer if more funding is contributed to it. (Sparks, 6 TR 2386.)

Regarding intervenors’ positions, many proposals were made to modify energy assistance, some of which Staff opposed in its rebuttal testimony. Staff witness Braunschweig addressed the issues raised by DAAO witnesses Koepfel (Koepfel, 6 TR 4393, 4432) and Arjun Makhijani (Makhijani, 6 TR 4626) to seek Commission approval for a universal affordability program available to all residential customers as well as DAAO witness Justin Schott’s (Schott, 6 TR 4506—07) recommendation for a unified affordability program that would cap all customers’ rates at six percent of income. Staff’s position on these proposals recommended Commission disapproval due to the MCL 460.11(1) and (2) and MCL 460.10(t), in which cost-based rates are legislatively mandated and low-income rates are allowed but restricted by eligibility defined in MCL 460.10(t). (6 TR 3541.) MCL 460.11(1) provides that electric rates must be equal to the cost of providing service to that customer class, while MCL 460.10t defines an eligible low-income customer for the purposes of the Act. The parameters of these provisions do not allow for the adoption of the proposals proffered by the DAAO. A unified

affordability cap of 6% of income for all customers runs roughshod over the requirements that classes rates be equivalent to the costs of providing that class with electric service. Furthermore, Staff points to 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. (6 TR 3541.) Staff therefore supported customers reaching out to receive assistance if eligible, but not requiring income reporting for all customers. (6 TR 3541-3542.)

Staff additionally disagreed with intervenors' proposals regarding PIPPs including DAAO witness Justin Schott's proposal to accelerate the development of a PIPP, DAAO witness Toyia Watts' proposal to implement a unified form of assistance or a PIPP, and DAAO witness Yunus Kinkhabwala's proposal to approve a PIPP for customers at or below 200% of the federal poverty level (FPL). (6 TR 4516, 4680, 4547-4548.) Staff witness Braunschweig recommended disapproval of these proposals by maintaining Staff's position in direct testimony that 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. (6 TR 3542.) Staff reiterated that it does not support the premature approval of a full-scale PIPP and recommends the Commission hold off on energy assistance reform until analysis and recommendations surrounding energy assistance can be completed.

(*Id.*) Consistent with the previous positions in this brief surrounding energy assistance eligibility, DAAO witness Kinkhabwala's recommendations to increase eligibility up to 200% of the FPL would run counter to the requirements of MCL 460.11(2) and MCL 460.10(t).

Staff witness Braunschweig additionally responded to positions taken in Intervenor's direct testimonies to financially quantify and close the energy affordability gap. DAAO witness Koeppel proposed the Commission approve a 0.743 cent per kWh surcharge for all customers to close the energy affordability gap for all residential customers based on DAAO witness Arjun Makhijani's calculations utilizing DTE's projections. (Koeppel, 6 TR 4393; Makhijani, 4598.) DAAO witness Kinkhabwala also proposed Commission approval of a 0.18 cent per kWh surcharge to only fund \$10 million in energy assistance, based on an assumption of \$90 million in "available" funding for the previously briefed proposed PIPP. (Kinkhabwala, 6 TR 4559, 4537-4538.) However, Staff could not find a calculation explaining how the witness calculated \$90 million in available funding but notes that witness Kinkhabwala likely included some funding from federal Low-Income Home Energy Assistance Program (LIHEAP) and Michigan Energy Assistance Program (MEAP). (Braunschweig, 6 TR 3543.) Staff's position on these proposals noted the lack of clarity around how a surcharge would be levied on all customers given DAAO's other proposals to limit all residential customer bills to six percent of income. (Braunschweig, 6 TR 3543.) Given the previously cited and interpreted statutes MCL 460.11(1) and MCL 460.11(2), there could be a significant revenue shortfall in

the residential class and difficulties complying with the statutes since the 0.743 cent per kWh surcharge would fund an affordability program for all residential customers struggling to pay their bills. (Braunschweig, 6 TR 3543-3544.) This means that customers with capped bills may not contribute any revenue toward the surcharge's fund, which would lead to revenue shortfalls in the assistance fund as well as in base rates, as previously discussed with compliance issues with MCL 460.11(1). (Braunschweig, 6 TR 3544.) Due to the issues with statutory compliance and revenue shortfalls, Staff does support the cited proposals and reinforced the need for energy assistance restructuring and recommendations to disseminate from the AAA subcommittee and Staff reports. (*Id.*) Despite DAAO witness testimony requesting simplified energy assistance offerings, DAAO proposals would further complicate energy assistance offerings, which undermines the work of the EAAC to coordinate, educate, and streamline the energy assistance landscape and the people who interact with the landscape. (*Id.*)

Lastly, Staff disagreed with many of NRDC/MEC witness Roger Colton's proposals, including maintaining the \$8.50 per month RIA credit amount but redirecting the credits to those with special needs up to 250% of the federal poverty level (FPL) or 60% of state median income (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. (Colton, 6 TR 3861—62.) Staff recommended the Commission not approve any of these modifications,

reinforcing its position that it is best to allow energy assistance analysis and recommendations disseminate from the AAA subcommittee until the conclusion of its work on this subject, especially since there are many misunderstandings about the complex energy assistance landscape, as many of the misgivings in intervenors' proposals demonstrate. (Braunschweig, 6 TR 3546.) Similar to other intervenors, NRDC/MEC witness Colton proposed raising the income eligibility on the RIA credit, which would conflict with MCL 460.11(2) and MCL 460.10(t). Therefore, Staff opposes these measures. (Braunschweig, 6 TR 3547.) Staff also opposes witness Colton's proposal to retain the RIA credit amount because the RIA has historically been equal to the monthly customer charge and Staff proposes maintaining that practice in the Commission's final order. (*Id.*) Staff additionally raised the issue that it is unclear how RIA and LIA customer pools would be distinct for customers with incomes 0-150% of the FPL. (*Id.*) As for witness Colton's proposal to make public assistance a qualifier to assistance, Staff points out that SNAP, Medicaid, MEAP and LIHEAP programs are already qualifiers for assistance. However, as Staff identified in EAAC discussions with MDHHS, with MEAP and LIHEAP auto-enrolling customers in RIA, MDHHS would not offer SNAP, Medicaid, or other non-LIHEAP assistance programs to release information to utilities to auto-enroll customers in the RIA. (Braunschweig, 6 TR 3547.) In Staff's response to the proposal to uncap enrollment for both RIA and LIA, Staff

points out that the RIA is already uncapped¹⁶, and that Staff does not support modifying the LIA credit amount, structure of the credit, nor increasing its enrollment until the credit is no longer under review for its use and effectiveness. (Braunschweig, 6 TR 3548.) Finally, Staff reiterates that it is imprudent to not estimate costs beforehand of proposals such as witness Colton’s new, tiered, LIA credit, even if costs would be reconciled. (Braunschweig, 6 TR 3548; Colton 6 TR 3894—95.) Approval of such unvetted proposals would be an imprudent use of ratepayer funds, which further reinforces the importance of the detailed analysis that can be expected from the AAA/PIPP reporting process.

In the Company’s rebuttal of NRDC/MEC witness Colton, Company witness Sparks also referred to MCL 460.11(2) and MCL 460.10t(6)(b) in response to the proposal to increase RIA eligibility to 250% of the FPL. (Sparks, 6 TR 2391.) Both Staff and the Company agree that under the current structure of the RIA, the statutes provide the authority and parameters for the RIA. Additionally, Company witness Sparks argued that witness Colton’s proposed “application of RIA and Lia credits to non-energy fees or services, arrears, and a tiered approach to credit application” would be best addressed by the EAAC workgroups, since work is underway to reform the RIA and LIA credits. (6 TR 2391.) Staff notes, however, that contrary to the Company’s approach of only certain RIA and LIA changes occurring in the EAAC while others happen in the present case, Staff recommends a

¹⁶ Enrollment numbers are projected in each rate case and costs are recovered by ratepayers. (Braunschweig, 6 TR 3548.)

consistent approach to the credit reform, with recommendations and energy assistance reform analysis disseminating from the EAAC/AAA subcommittee. For these reasons, Staff urges the Commission to defer approving any programmatic changes to the LIA credit until the Commission's Affordability, Alignment, and Assistance subcommittee can complete its relevant work and analysis, as ordered previously by the Commission in the December 21, 2023, Order in U-20757.

G. Tree Trimming and Related Recommendations

(Citations in Section XI.G.:

Foley, 2 TR 129, 167-170; Steudle, 6 TR 2983, 2989; Hill (Rebuttal) 6 TR 3087; Denzler, 6 TR 3769; Stults 6 TR 4260; Bunch 6 TR 4332; Bellini, 6 TR 3176; Duell, 6 TR 5147;

In re Consumers Energy 2021 Electric Rate Case, No. U-20963, 12/22/2021 Order;

In re Consumers Energy 2020 Electric Rate Case, U-20697, 12/17/2020 Order;

In re Consumers Energy 2024 Electric Rate Case, MPSC Case No. U-21389, 3/1/2024 Order.)

1. Tree Trimming

Staff has several recommendations regarding tree trimming that the Commission should adopt, each of which is discussed below. Staff witness Jessica Duell supported the Company's proposal to spend \$109,000,000 in Base O&M expenses for the 2025 calendar year for tree-trimming, as proposed by Company witness Rachel C. Steudle. (Steudle, 6 TR 2983).

Staff witness Duell also supported the Company's request for \$87,000,000 in incremental regulatory asset to complete the surge program (Steudle, 6 TR 2983).

Company witness Steudle recommended that the Company go towards a risk-based tree trim cycle after the Company completes the surge program. Company witness Steudle stated the Company (with the use of LiDAR technology) will be adjusting cycle lengths based on tree species growth rates and risk of outages. (6 TR 2989.) Staff witness Duell recommended waiting on results of the audit ordered in MPSC Case U-21305 to determine if risk-based cycle tree trimming is an appropriate next step for DTE's tree trimming program after the surge program is completed. (Duell, 6 TR 5146.) DTE did not rebut Staff's recommendation to wait before proceeding to a risk-based cycle.

Company witness Steudle recommended an alternative method to study the incremental benefit and cost of expanding the trimming on Zone 2 and Zone 3. The Company will compare circuits trimmed on a regular maintenance program versus circuits trim for construction projects. (6 TR 2994—95). Staff witness Duell supported DTE's proposal to look at circuits trimmed on regular maintenance versus circuits trimmed during construction projects. (6 TR 5147.)

2. Storm Restoration Recommendations

Staff has several recommendations regarding Storm Restoration that the Commission should adopt, each of which is discussed below. Staff witness Duell supported the Company's proposal to spend \$64,500,000 for the projected test year O&M expense in service restoration. (Foley, 2 TR 129.)

Staff witness Duell recommends DTE provide a brief description in future cases of what the Company defines as storm restoration expenses and describe what the Company plans on spending their storm restoration expenses on. (6 TR 5147.) Company witness Hill replied in rebuttal testimony that he agrees with Staff's recommendation to improve testimony describing the work performed under Emergent Replacement Storm. (Hill (Rebuttal), 6 TR 3087.)

Staff witness Duell testified that Staff does not support the Storm Restoration Cost Sharing Mechanism. Staff submits that this mechanism should not be approved for several reasons. First, Staff is supporting the full-service restoration expense for the test year. Second, the Commission rejected similar mechanisms in prior MPSC Case No. U-20963, U-20697, and U-21389, and Storms are progressively getting worse each year. Third, Customers may never see a benefit from the proposed storm restoration mechanism due to the Company spending over the requested amounts each year. Fourth, the way the Company currently recovers storm restoration expenses provides a stronger incentive to control costs than the Storm Restoration Cost Sharing Mechanism. The Company currently keeps 100% of savings, rather than 50%, and absorbs 100% of costs overages, rather than 50%. The Company's proposal dulls these incentives. (Duell, 6 TR 5149.)

Witness Denzler on behalf of MNSC and witness Stults on behalf of AA both did not support the Storm Restoration Cost Sharing Mechanism (SRCSM). Witness Denzler testified that the SRCSM will skew costs of storms against customer and in favor of the Company and its shareholders. (Denzler, 6 TR 3769.) Witness Stults

stated in her testimony the SRCSM could cause the company to play a shell game with capital recovery if the SRCSM were approved. It would reward the Company for projecting high estimates for storm restoration costs. Concurrently, ratepayers would be paying for investments to improve resiliency of the grid that would result in lower storm restoration costs but would then only see half the benefit of reduced storm restoration costs. (Stults, 6 TR 4260.)

DTE rebutted Staff's recommendation of not supporting the Storm Restoration Cost Sharing Mechanism. Company witness Foley states the current approach to storm restoration O&M expense recovery does not address the uncertainty and variability of these expenses in any given year and exposes both customers and the Company to financial risk. He goes on to state that the proposed SRCSM is designed to address this uncertainty and variability by enhancing the existing approach of recovering storm restoration expenses, not replacing it. The Company also disagrees that the Commission has rejected similar mechanisms in MPSC Case Nos. U-20963, U-20697, and U-21389 because in these prior cases Consumers Energy proposed a cost tracker where in the current rate case the Company is proposing a cost sharing mechanism. (Foley, 2 TR 167,168.)¹⁷

DTE rebutted witness Denzler's recommendation to not support the Storm Restoration Cost Sharing Mechanism. Company witness Foley stated in his rebuttal

¹⁷ Staff witness Jessica Duell had included another argument against the SRCSM in her direct testimony, which involved the third-party audit in Case No. U-21305, and the Company filed rebuttal testimony against it, but Staff is not including this argument in its brief.

testimony that storm restoration O&M costs are uncertain and volatile. The proposed SRCSM protects both customers and the Company from financial risk through equal sharing of costs that deviate from projections. (*Id.*) DTE also rebutted witness Stults' recommendation of not supporting the Storm Restoration Cost Sharing Mechanism. Company witness Foley stated the SRCSM does not impact capital recovery, it is a mechanism that addresses uncertainty and variability of O&M expenses only. He further stated that the current approach to projecting storm restoration O&M expenses is formulaic based on historical average spending adjusted for inflation. Company witness Foley states the Company cannot simply project a very high estimate as suggested by witness Stults. Company witness Foley stated under the proposed SRCSM more saving would be returned to customers than the current approach that is in place. (Foley, 2 TR 169, 170.)

After reading and reviewing DTE rebuttal testimony and other parties' testimony, Staff witness Duell still concludes that the Storm Restoration Cost Sharing Mechanism should not be supported by the Commission. Staff has approved the full spend for service restoration that the Company requested for the projected test year. By Staff recommending the Company receive the full spend for service restoration, this should allow the Company to cover the expenses they accrue from the storms that may potentially occur.

3. Streetlighting Recommendations

Company witness Bellini stated in his direct testimony, Given the technical complexity of HID to LED conversions, the Company would be amenable to a Staff

facilitated technical workshop inclusive of Leotek's engineering team, DTE, expert consultants, and MI-MAUI with the intent of evaluating appropriate HID to LED equivalent conversion employed by DTE and determine whether or not DTE unnecessarily installed more expensive LEDs during conversion. (6 TR 3122.) MI-MAUI stated in testimony that they would not support convening of a technical workshop at this time. If the Commission were presented here with relevant technical evidence about which experts could reasonably disagree, then convening a technical collaborative might make sense. (Bunch (Revised), 6 TR 4332.) Company witness Bellini stated in rebuttal that it would be reasonable to recommend that Staff conduct a technical workshop or joint collaborative that includes Consumers, so the parties can compare and contrast Consumers' LED selection methodology to DTE's. DTE would also like to see LED lighting manufacturer Leotek, lighting industry experts Dr. Ronald Gibbons and Mr. McLean, MI-MAUI, and any other interested intervenors or experts participate in this technical workshop or collaborative. The purpose of this workshop or collaborative should be to establish an agreed-upon standard when selecting common LED fixtures best suited for municipal streetlighting customers served by DTE. (Bellini, 6 TR 3176.) Staff witness Duell has read both MI-MAUI and DTE's recommendations regarding a technical workshop or collaborative for streetlighting. Staff recommends the Commission adopt in the order that Staff shall work with interested parties to conduct a technical conference regarding streetlighting. Staff believes a technical conference would help Staff, MI-

MAUI, and DTE better understand streetlighting and come to conclusions on what best fits DTE regarding HID to LED conversions.

H. The commission should make no other adjustments to the strategic capital programs.

(Citations in Section XI.H.:

Durfee, 6 TR 5157; York 6 TR 3360; Alvarez 6 TR 3978; Stephens, 6 TR 4025; Koeppel, 6 TR 4414; Deol (Revised Rebuttal), 5 TR 1235, 1263, 1268; Hartwick, 4 TR 851;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 12/1/2023 Order.)

Staff 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.)

1. Staff responds to the testimony of ABATE witness York regarding the Strategic Capital projects.

ABATE witness York recommended that the Commission disallow the strategic capital projects that are not expected to be in-service during the bridge period and projected test year. This is a reduction of \$613.586 million. (6 TR 3360.)

Company witness Deol rebutted the disallowance, recommending the Commission disregard Witness York's recommendation. Witness Deol referred to Company witness Uzenski's direct testimony, which states that capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Deol also stated that the Commission

found witness York's similar proposed adjustments in MPSC Case No. U-21297 unpersuasive because whether a project will be completed within the test year does not determine whether that project belongs in rate base. (Deol (Revised Rebuttal), 5 TR 1268.)

Staff agrees 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.

2. Staff responds to AG-MN regarding Grid Automation Telecommunications.

AG-MN witness Alvarez recommended the commission disallow telecommunications plan costs incurred in 2022 and remove all bridge and test year spending because: 1) DTE has not developed a benefit-cost or make vs. buy analysis; 2) the Company has not complied with the Commission's order to analyze alternatives; and 3) that DTE refused to provide the plan. (6 TR 3978.)

Company witness Hartwick rebutted stating that: 1) the Company did provide details in her direct testimony, discovery, and in the distribution grid plan; 2) the Company complied with the Commission's request for an alternative analysis; and 3) the Company is committed to a benefit cost analysis in its next rate case. (4 TR 851.)

3. Staff responds to AG-MN regarding the Strategic Undergrounding Pilot.

AG-MN witness Stephens recommended the disallowance of the Company's Underground Pilot program. He stated that while underground lines offer

reliability and safety benefits, they are also subject to reliability risk from flooding and careless excavation along with safety risks from excavation and contact voltage. He also stated that undergrounding is cost ineffective. (Stephens, 6 TR 4025.)

Witness Deol rebutted, stating that the undergrounding pilots were a result of the Company being asked in Case No. U-20169 to explore pilot projects to eliminate 4.8kV ungrounded delta rear-lot overhead infrastructure and its hazards. Along with the safety benefits, undergrounding also improves reliability and resiliency from lack of tree impacts, can eliminate the need for trimming and pole top maintenance programs, reduce storm restoration costs, and in some cases gain efficiency where other construction is occurring.

Other utilities are successfully using undergrounding to improve their system resiliency, and there are customers and communities that are reaching out and asking the Company to underground utilities. Witness Deol also points out that there is a significant amount of learning that comes from the undergrounding pilots. (5 TR 1263.)

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.

4. Staff responds to regarding the CODI program.

DAAO witness Koepfel recommended that the Commission reject or substantially reduce DTE's proposed capital spending on the CODI program, especially in the Core Area. He stated that witness Deol and witness Kryscynski

have conflicting arguments. Witness Deol stated customers in the target areas are experiencing poor reliability due to load growth and aging infrastructure, while the maps presented by witness Kryscynski show a large portion of those target areas as being in the first and second quartiles for reliability performance. (6 TR 4414.)

Witness Deol rebutted, stating that the CODI area is served primarily underground. Its reliability is dependent upon the ability to have redundant capacity to transfer load in the event of cable failures or planed shutdowns. The drivers for the CODI projects were not driven completely by reliability improvement, but also to address capacity for load growth, maintaining sufficient redundancy, and addressing aging infrastructure. It is not appropriate to compare the project drivers and reliability performance of an all-underground system with an overhead system. He also stated that the Commission should consider benefits not only to customers in the immediate CODI area, but also benefits to customers served by those facilities in the Company's broader service territory. The customer base in the CODI area includes many important customers critical to the health and well-being of the entire City of Detroit populace. Investments in the electrical infrastructure in the CODI footprint will benefit all citizens of the city of Detroit and the surrounding communities. (5 TR 1235.)

Staff supports the projected spending for nearly all of the strategic capital programs. The projected numbers are in line with the Company's current path to improve the reliability, resilience and safety of the electric system.

XII. Conclusion

Staff recommends that the Commission find that DTE Electric's total revenue deficiency will be \$237,179,000. Staff recommends that the Commission Staff's lower rate base, return on equity and operating expenses, as well as Staff's proposed cost of service, rate design and tariff revisions. Staff's recommendations strike the right balance between DTE Electric's interests and its ratepayers' interests.

Respectfully submitted,

**MICHIGAN PUBLIC SERVICE
COMMISSION STAFF**

A handwritten signature in black ink that reads "Heather M.S. Durian". The signature is written in a cursive, flowing style.

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DATED: October 3, 2024

APPENDIX A

Michigan Public Service Commission
DTE Electric Company
Projected Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 MPSC Staff Initial Brief
Appendix A

Line No.	(a) Description	(b) Source	(c) Applicant Projection	(d) Staff Adjustment	(e) Staff Projection
1	Rate Base	Appendix B	\$ 22,107,989	\$ (162,560)	\$ 21,945,429
2	Adjusted Net Operating Income	Appendix C	\$ 1,087,100	\$ 88,219	\$ 1,175,319
3	Overall Rate of Return	Line 2 ÷ Line 1	4.92%	0.44%	5.36%
4	Required Rate of Return	Appendix D	5.92%	-0.26%	5.66%
5	Income Requirements	Line 1 x Line 4	\$ 1,309,478	\$ (67,401)	\$ 1,242,077
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	\$ 222,378	\$ (155,620)	\$ 66,758
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	<u>1.3496</u>	<u>-</u>	<u>1.3496</u>
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	\$ 300,129	\$ (210,030)	\$ 90,099
9	Return On - Tree Trim Regulatory Asset	Appendix A1.1	18,786	(8,653)	10,133
10	Return On - Monroe Regulatory Asset	Appendix A1.2	<u>137,518</u>	<u>(572)</u>	<u>136,947</u>
11	Revenue Deficiency / (Sufficiency)-Total	Sum Lines 8, 9, 10	<u>\$ 456,434</u>	<u>\$ (219,255)</u>	<u>\$ 237,179</u>

APPENDIX B

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Return On
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
MPSC Staff Initial Brief
Appendix A1.1

(a)		(b)					(c)		
Line No.	Description	Test Period Amount					Reference		
1	<u>Return on Tree Trim Regulatory Asset</u>								
2	Average Balance Regulatory Asset	275,450					Line 16		
3	Deferred Tax Liability	(71,342)					- Line 2 x 25.9% Composite Tax Rate		
4	Average Net Rate Base	204,108							
5	Staff Rate of Return on Short-Term Debt	4.96%					Exhibit S-4, Schedule D3		
6	Return on Tree Trim	10,133							
		<u>2019-A</u>	<u>2020-A</u>	<u>2021-A</u>	<u>2022-A</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	
7	<u>Tree Trim Regulatory Asset</u>								
8	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	52,700	43,700	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges through April 30, 2020 1/		1,200						
10	Additional Funding Request	-	-	-	-	-	-	87,000	Exhibit A-13 C5.6.1, Line 3
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	52,700	130,700	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	157,400	210,100	340,800	Cumulative Line 11
13	Approved for Securitization 2/				(156,900)				Case U-21015
14	Cumulative Balance at December 31				90,400	157,400	210,100	340,800	
15	Cumulative Balance at December 31						210,100	340,800	Assumes 100% of annual spend
16	Average Balance							275,450	

1/ Interest at U-20162 authorized STD rate of 3.56% until U-20561 order was in effect.

2/ Securitization approved per U-21015 order dated June 23, 2021 (up to \$156.9 per order page 91)

APPENDIX C

Michigan Public Service Commission
DTE Electric Company
Monroe Regulatory Asset - Return On
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 MPSC Staff Initial Brief
Appendix A1.2

	(a)	(b)	(c)
Line		Test Period	
No.	Description	Amount	Reference
1	<u>Return on Monroe Regulatory Asset</u>		
2	Monroe Regulatory Asset - Average Balance	2,093,063	Exhibit A-12, Schedule B4.4, Line 8
3	Pre-tax Weighted Average Cost of Capital 1/	<u>6.54%</u>	Exhibit S-4, Schedule D1
4	Return on Monroe Regulatory Asset	<u>136,947</u>	

1/ Pretax WACC as proposed in this case was recalculated using 9% ROE in accordance with U-21193 order dated July 26, 2023

APPENDIX D

**Michigan Public Service Commission
DTE Electric Company**

Projected Rate Base

**Periods Ending December 31, 2022 and December 31, 2025
(\$000)**

Case No.: U-21534
MPSC Staff Initial Brief
Appendix B

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Source	Applicant Projection	Staff Adjustments	Staff Projection
1	<u>Utility Plant in Service:</u>				
2	Plant in Service	Exh. A-12, Sch. B2, L6	24,872,100	(166,406)	24,705,694
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	22,532	-	22,532
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	2,450,590	-	2,450,590
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	83,332	-	83,332
6	Total Utility Plant	Sum Lines 2 thru 5	27,428,555	(166,406)	27,262,149
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(6,777,289)	14,521	(6,762,768)
8	Net Utility Plant	Line 6 + Line 7	20,651,266	(151,885)	20,499,380
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	6,051	-	6,051
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	-	-	-
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	162,350	-	162,350
12	Total Utility Property and Plant	Sum Lines 8 thru 11	20,819,666	(151,885)	20,667,781
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L85 + L100	7,049	-	7,049
14	Net Plant	Line 12 - Line 13	20,812,617	(151,885)	20,660,732
15	Allowance for Working Capital	Exh.A-12, Sch. B4	1,295,372	(10,675)	1,284,697
16	Total Rate Base	Line 14 + Line 15	22,107,989	(162,560)	21,945,429

APPENDIX E

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21534
MPSC Staff Initial Brief
Appendix C

DTE Electric Energy Company

Development of Projected Net Operating Income
for the Test Year Ended December 31, 2025
(\$000)

Line No.	(a) Description (Witness)	Revenue				Expenses									NOI			
		(b) Sales Revenue	(c) Base Fuel & Purchase Power Rev.	(d) Other Revenue and R2 Rider	(e) Total	(f) Fuel and Purchased Power	(g) Other O&M Expense	(h) Depreciation & Amort.	(i) Property Taxes	(j) Other Taxes	(k) State & Local Income Taxes	(l) FIT	(m) Other Utility (Income) / Deductions	(n) Total	(o) NOI	(p) AFUDC	(q) Loss on Reacquired Securities	(r) Adjusted NOI
1	Company Filed																	
	Operating Income (Initial Filing)	3,995,976	1,354,105	115,336	5,465,416	1,354,105	1,266,950	1,266,245	328,772	53,180	61,413	107,776	(6,400)	4,432,041	1,033,375	55,969	(2,244)	1,087,100
	Staff Adjustments																	
2	Revenue																	
3																		
4	RIA	2,740			2,740						170	540		710	2,030			2,030
5	Senior Credit	495			495						31	97		128	367			367
6																		
7	Steam Power Generation (Kindschy)						(19,392)				1,204	3,820		(14,369)	14,369			14,369
8																		
9	Fuel Supply & MERC Fuel Handling (Kindschy)						(463)				29	91		(343)	343			343
10																		
11	Nuclear Power Generation (Kindschy)						(371)				23	73		(275)	275			275
12																		
13	Other Power Generation (Kindschy)						(3,009)				187	593		(2,229)	2,229			2,229
14																		
15	Customer Service																	
16	Merchant Fees (McMillan-Sepkoski)						(1,231)				76	242		(912)	912			912
17																		
18	Uncollectible Accounts Expense (Rueckert)						(9,841)				611	1,938		(7,292)	7,292			7,292
19																		
20	Regulated Marketing (McMillan-Sepkoski)						(292)				18	58		(216)	216			216
21																		
22	Corporate Support																	
23	Injuries & Damages (Rueckert)						(2,863)				178	564		(2,121)	2,121			2,121
24	Incentive Compensation (McMillan-Sepkoski)						(39,233)				2,436	7,727		(29,069)	29,069			29,069
25	Restricted Stock (McMillan-Sepkoski)						(8,960)				556	1,765		(6,639)	6,639			6,639
26	Projects with Level 2 Cost Estimates (Rogers)						(2,386)				148	470		(1,768)	1,768			1,768
27	Projects with Level 3 Cost Estimates (Rogers)						(84)				5	17		(62)	62			62
28	Cost to Achieve Projected Expense (Rogers)						(3,174)				197	625		(2,352)	2,352			2,352
29																		
30	Pension & Benefits																	
31	Employee Savings Plan (Rueckert)						(7,859)				488	1,548		(5,823)	5,823			5,823
32	Active Healthcare (Rueckert)						(2,334)				145	460		(1,729)	1,729			1,729
33	Other Benefits - General Benefits (Rueckert)						(1,344)				83	265		(996)	996			996
34	Other Benefits - Admin Fees (Rueckert)						(2,588)				161	510		(1,918)	1,918			1,918
35																		
36																		
37																		
38																		
39																		
40																		
41																		
42																		
43	Impact of Cap Ex Adj on Prop. Tax & Depr. (Hecht)							(12,839)	(693)		840	2,665		(10,026)	10,026			10,026
44																		
45	Impact of Cap Ex Adj on Depreciation (Hecht)																	
46	Proforma Interest (Nichols)										555	1,760		2,315	(2,315)			(2,315)
47	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	1	2	-	2	(2)	-	-	(2)
48	Total Adjustments	3,235	-	-	3,235	-	(105,424)	(12,839)	(693)	-	8,143	25,828	-	(84,984)	88,219	-	-	88,219
49	Staff NOI - Test Year	<u>3,999,211</u>	<u>1,354,105</u>	<u>115,336</u>	<u>5,468,651</u>	<u>1,354,105</u>	<u>1,161,527</u>	<u>1,253,406</u>	<u>328,080</u>	<u>53,180</u>	<u>69,557</u>	<u>133,604</u>	<u>(6,400)</u>	<u>4,347,057</u>	<u>1,121,594</u>	<u>55,969</u>	<u>(2,244)</u>	<u>1,175,319</u>

APPENDIX F

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For the 13-Month Average Period Ending Dec. 31, 2025

Case No.: U-21534
MPSC Staff Initial Brief
Appendix D

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure			Cost Rate %	Weighted Costs			
		Amount (\$000)	Percent Permanent Capital	Percent of Total Capital		Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long-Term Debt	8,663,922	50.0%	39.19%	4.21%	2.11%	1.65%	1.0000	1.65%
2	Preferred Stock	0	0.0%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	8,673,528	50.0%	39.23%	9.90%	4.95%	3.88%	1.3496	5.24%
4	Total	17,337,450	100.0%			7.06%			
5	Short-Term Debt	509,454		2.30%	4.96%		0.11%	1.0000	0.11%
6	Investment Tax Credit (ITC) - Debt	15,734		0.07%	4.21%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	15,751		0.07%	9.90%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	31,485							
9	Deferred Income Taxes (Net)	4,229,600		19.13%	0.000%		0.00%		0.00%
10	Total	22,107,989		100.00%			5.66%		7.02%

APPENDIX G

Michigan Public Service Commission
DTE Electric Company
Capital Expenditure and Rate Base Adjustments
Projected Balances Period Ending December 31, 2025
(\$000)

Appendix E
MPSC Staff Brief
Case No. U-21534
Page 1 of 3

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax
1	Production:							
2	Steam - Total Non-Routine Update for Actuals		(3,710)	(3,710)	(138)	(3,572)	(119)	-
	Steam - Non-Routine Monroe Bottom Ash Conv. Update for Revisions		(1,910)	(955)	(15)	(940)	(31)	-
3	SUBTOTAL: STEAM NON-ROUTINE		(5,620)	(4,665)	(153)	(4,512)	(150)	-
4								
5	Steam - Routine Maintenance >\$1 Million Update For Actuals through April 2024		(21,333)	(21,333)	(648)	(20,686)	(687)	-
6	Steam - Routine Maintenance >\$1 Million Apply Cost Estimates May 2024 - Dec 2025		(39,100)	(24,874)	(572)	(24,303)	(801)	-
7	SUBTOTAL: STEAM ROUTINE		(60,433)	(46,208)	(1,219)	(44,988)	(1,488)	-
8	Other - Non-Routine - Blackstart Project 10570 & 20255		(611)	(611)	(20)	(591)	(13)	(11)
9	Other - Non-Routine - Blackstart Project 17611		(906)	(906)	(21)	(886)	(20)	(10)
10	Other - Non-Routine - Blackstart Project 18320		(1,077)	(1,077)	(45)	(1,032)	(23)	(28)
11	Other - Non-Routine - Slocum Battery Project		(2,178)	(2,178)	(47)	(2,131)	(47)	(23)
12	Other - Non-Routine - Trenton Channel Energy Center BESS		(9,910)	No Impact as This Portion of CapEx is in CWIP				(8)
13	SUBTOTAL: OTHER - NON-ROUTINE		(14,683)	(4,773)	(133)	(4,640)	(103)	(81)
14	MERC / Fuel Supply Update for Actuals and Forecast		(103)	(103)	(8)	(95)	(3)	(3)
15	SUBTOTAL: MERC / FUEL SUPPLY		(103)	(103)	(8)	(95)	(3)	(3)
16	TOTAL: PRODUCTION		(80,839)	(55,748)	(1,513)	(54,235)	(1,745)	(84)
17	Nuclear:							
18	Nuclear Routine and Small Projects Update For Actuals Through April 2024		(7,870)	(7,870)	(397)	(7,473)	(335)	-
19	Nuclear Non-Routine and Large Projects Update For Actuals Through April 2024		(7,874)	(7,874)	(351)	(7,522)	(336)	-
20	Nuclear Routine and Small Projects Apply Cost Estimates May 2024 - Dec 2025		(12,227)	(7,982)	(250)	(7,733)	(340)	-
21	Nuclear Non-Routine and Large Projects Apply Cost Estimates May 2024 - Dec 2025		(17,579)	(13,737)	(504)	(13,234)	(586)	-
22	TOTAL: NUCLEAR		(45,550)	(37,463)	(1,502)	(35,961)	(1,597)	-
23	Distribution:							
24	Total Base Capital Underspend		(25,202)	(25,202)	(2,071)	(23,131)	(1,036)	(576)
25	Strategic Capital Programs - Technology and Automation - NWA: Adaptive Networked Microgrids		(30,138)	No Impact as This Portion of CapEx is in CWIP				(24)
26	Strategic Capital Programs - Technology and Automation - NWA: Adaptive Networked Microgrids - Project Contributions		15,718	No Impact as This Portion of CapEx is in CWIP				14
27	TOTAL: DISTRIBUTION		(39,622)	(25,202)	(2,071)	(23,131)	(1,036)	(586)

APPENDIX H

Michigan Public Service Commission
DTE Electric Company
Capital Expenditure and Rate Base Adjustments
Projected Balances Period Ending December 31, 2025
(\$000)

Appendix E
MPSC Staff Brief
Case No. U-21534
Page 2 of 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Total	Test Year Impacts From Staff Adjustment(s)				
Line	Adjustment Description	Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax
28	<u>Demand Side Management:</u>						
29	Other Demand Response Programs and Pilots - C&I Battery Pilot	(2,000)	(1,700)	(310)	(1,390)	(340)	(15)
30	TOTAL: DEMAND SIDE MANAGEMENT	(2,000)	(1,700)	(310)	(1,390)	(340)	(15)
31	<u>Information Technology:</u>						
32	Infrastructure Operations - Digital Worker Experience EOL	(547)	(423)	(100)	(323)	(85)	-
33	SUBTOTAL: Information Technology Projects	(547)	(423)	(100)	(323)	(85)	-
34	Corporate Applications - Level 2 Cost Estimates - 20%	(5,052)	(3,814)	(639)	(3,175)	(763)	-
35	Customer Service - Level 2 Cost Estimates - 20%	(7,908)	(6,055)	(684)	(5,371)	(807)	-
36	Plant and Field - Level 2 Cost Estimates - 20%	(9,955)	(7,714)	(1,319)	(6,395)	(1,543)	-
37	IT for IT - Level 2 Cost Estimates - 20%	(3,663)	(3,494)	(682)	(2,812)	(699)	-
38	Information Protection Security - Level 2 Cost Estimates - 20%	(2,185)	(1,756)	(308)	(1,447)	(351)	-
39	Infrastructure Operations - Level 2 Cost Estimates - 20%	(13,221)	(9,220)	(1,251)	(7,969)	(1,598)	-
40	Enterprise Data Analytics - Level 2 Cost Estimates - 20%	(618)	(465)	(78)	(387)	(93)	-
41	SUBTOTAL: LEVEL 2 COST ESTIMATES	(42,602)	(32,518)	(4,960)	(27,557)	(5,854)	-
42	Corporate Applications - Level 3 Cost Estimates - 10%	(431)	(431)	(172)	(258)	(86)	-
43	Customer Service - Level 3 Cost Estimates - 10%	(3,038)	(3,038)	(810)	(2,228)	(405)	-
44	Plant and Field - Level 3 Cost Estimates - 10%	(1,997)	(1,997)	(799)	(1,198)	(399)	-
45	IT for IT - Level 3 Cost Estimates - 10%	(249)	(249)	(100)	(149)	(50)	-
46	Information Protection Security - Level 3 Cost Estimates - 10%	(659)	(527)	(171)	(356)	(105)	-
47	Infrastructure Operations - Level 3 Cost Estimates - 10%	(5,910)	(5,630)	(1,784)	(3,846)	(976)	-
48	Enterprise Data Analytics - Level 3 Cost Estimates - 10%	(400)	(400)	(160)	(240)	(80)	-
49	SUBTOTAL: LEVEL 3 COST ESTIMATES	(12,684)	(12,272)	(3,996)	(8,276)	(2,102)	-
50	TOTAL: INFORMATION TECHNOLOGY	(55,832)	(45,213)	(9,057)	(36,156)	(8,040)	-

APPENDIX I

Michigan Public Service Commission
DTE Electric Company
Capital Expenditure and Rate Base Adjustments
Projected Balances Period Ending December 31, 2025
(\$000)

Appendix E
MPSC Staff Brief
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Page 3 of 3

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax
51	Corporate Staff:							
52	Other Miscellaneous - Emergent Spend For Storage Tank Removal/Cleanup		(1,440)	(1,080)	(68)	(1,012)	(82)	(8)
53	TOTAL: CORPORATE STAFF		(1,440)	(1,080)	(68)	(1,012)	(82)	(8)
54	<u>TOTAL CAPITAL EXPENDITURE ADJUSTMENTS</u>		<u>(225,283)</u>	<u>(166,406)</u>	<u>(14,521)</u>	<u>(151,885)</u>	<u>(12,839)</u>	<u>(693)</u>
55	<u>WORKING CAPITAL ADJUSTMENTS</u>							
56	Non Utility Balance included in Other Accounts Receivable Total					(6,111)		
57	Charging Forward - Residential Customer Rebates & Business and eFleet Charger Rebates					(4,564)		
58	TOTAL: WORKING CAPITAL					(10,675)		
59	TOTAL RATE BASE ADJUSTMENTS					<u>(162,560)</u>		

APPENDIX J

Michigan Public Service Commission
DTE Electric Company
Summary of Staff Position
Projected Balances Period Ending December 31, 2025

Appendix F
MPSC Staff Brief
Case No. U-21534

	(a)	(b)	(c)	(d)	(e)
Line	Description	Source	Rate Base	Pre-Tax	Revenue Requirement Impact (million \$)
Walk from DTE Revenue Deficiency (Initial Filing) to Staff Initial Brief					(million \$)
1	Company Revenue Deficiency (Initial Filing)				\$ 456.434
2	Staff Adjustments				
3	Rate base	Appendix E * Exhibit A-14, Sch D-1	(162.560)	7.37%	\$ (11.974)
4	Rate of return	Appendix B * (Appendix D less Exh A-14)	21,945.429	-0.35%	(75.866)
5	Revenue	Appendix C, line 48			(3.235)
6	O&M Expense	Appendix C, line 48			(105.424)
7	Depreciation	Appendix C, line 48			(12.839)
8	Property Tax	Appendix C, line 48			(0.693)
9	AFUDC	Appendix C, line 48	-	1.3496	-
10	Return on Tree-trm Reg Asset	Appendix A, line 9			(8.653)
11	Return on Monroe Reg Asset	Appendix A, line 10			(0.572)
12	Total Staff adjustments (rev. req. impact)	Appendix A, line 11			\$ (219.255)
13	Staff Revenue Deficiency (Initial Brief)	Appendix A, line 10			\$ 237.179
Walk from Staff Initial Filing to Staff Initial Brief Revenue Deficiency					(million \$)
14	Initial Filing - Staff Revenue Deficiency	Exh S-1, Schedule A-1			\$ 239.833
15	Rate base	See Below	(21.584)	7.02%	(1.515)
16	Depreciation	Appendix C, line 48			(0.569)
17	Property Tax	Appendix C, line 48			(0.576)
18	O&M	See Below			0.005
19	AFUDC	Appendix C, line 48	-	-	-
20	Initial Brief - Staff Revenue Deficiency				237.179
Walk from Staff Initial Filing O&M to Staff Initial Brief O&M					(\$000)
21	Staff Initial Filing	Initial Filing, Schedule C1			\$ 1,161,522
22	Merchant Fees	Initial Brief, Appendix C, line 16			5
23					
24					
25					
26					
27					
28					
29					
30					
31					-
32	Staff Initial Brief	Initial Brief, Appendix C, line 41			\$ 1,161,527
Walk from Staff Initial Filing Rate Base to Staff Initial Brief Rate Base					(\$000)
33	Staff Initial Filing	Initial Filing, Schedule B1			\$ 21,967,013
34	Distribution - Base Capital Programs	Initial Brief, Appendix E, line 24			\$ (25,202)
35	IT Projects - Return to Health	Initial Brief, Appendix E, line 32			2,335
36					-
37	Accumulated Deprecation				1,283
38	Staff Initial Brief	Initial Brief, Appendix B, line 16			\$ 21,945,429

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. **U-21534**
(e-file paperless)

/

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF EATON)

De Ann Payne, being first duly sworn, deposes and says that on **October 3, 2024**, she served a true copy of **Michigan Public Service Commission Staff's Brief** upon the following parties **via email only**:

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**Environmental Law & Policy
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Solar**

Nicholas N. Wallace

Daniel Abrams

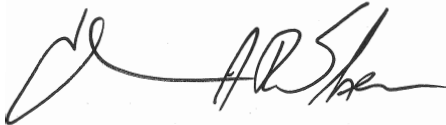
nwallace@elpc.org

dabrams@elpc.org



De Ann Payne

Subscribed and sworn to before me
this 3rd day of **October, 2024**.



Cherie A. R. Shea, Notary Public
State of Michigan, County of Jackson
Acting in the County of Eaton
My Commission Expires: 04-13-31