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 REPLY BRIEF

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I. Introduction

(Citations in section: Appendices A, C, and F.)

In accordance with the schedule established for this case, Staff files this reply brief. Staff maintains its overarching position that its proposed rate base, return on equity, and operating expenses strike the right balance between shareholders' and customers' interests.

Staff has, however, made changes reflecting revisions that the DTE Electric Company made in its initial brief, adopting Staff's and other parties' positions, and revisions that Staff has made to update working capital for the shared asset deferral mechanism. Those changes are described in this reply brief and the attached appendices.

While Staff reasserts the correctness of each of its positions taken in its initial brief and this reply brief, supported by its testimony and exhibits, Staff now selectively responds to arguments made by the parties that require additional emphasis and explanation. The Commission should not consider Staff's silence on any argument raised by another party as an agreement with that party's position.

In its initial filing, the DTE Gas Company (DTE , DTE Gas or Company) calculated a revenue deficiency of $456.434 million. Subsequently, DTE adjusted its case, making several adjustments in its initial brief, which resulted in a revised revenue deficiency of $446.063 million. In Staff's initial brief, Staff calculated a revenue deficiency of $237.179 million. In this reply brief, Staff has adopted DTE's ACCP/TOU amortization O&M concession, amortization of deferred incentive compensation O&M concession, IT MIGP Scope 3 rate base concession, operational incentive compensation rate base concession, and deferred incentive compensation rate base concession. (Appendix F, ln 29—30, 40—43.) Additionally, Staff has updated its calculation for IT projects with level 2 and 3 cost estimates and adopted DTE's calculations for DO underspend 2023. (Appendix F, ln 31, 44.)

In this reply brief, Staff now supports a revenue deficiency of $235.230 million. (Appendix A.) Staff's proposed revenue deficiency is $210.832 million less than the Company's as detailed in Appendix F. Staff has prepared Appendices A through F which calculate the Staff's revenue deficiency. Appendix C details revenue and expense adjustments, while Appendix E details rate base adjustments. Appendix F reconciles Staff's direct testimony, initial brief, and reply brief positions for revenue deficiency, O&M, and rate base. (Appendix F, ln 14—25, 26—33, 34—46.) Appendix F also reconciles the revenue deficiency in the Company's initial filing to the Company's initial brief position, and the Company's initial brief position to the Staff's reply brief position. (Appendix F, ln 1—13.)

I. Net Operating Income

(Citations in Section: DTE's Initial Brief, pp 250, 254—255.)

A. Staff replies to the Company's initial brief concerning Net Operating Income (NOI) with respect to the Company's healthcare benefits.

With respect to NOI and the Company's healthcare benefits, Staff disagrees with the Company presenting its recommendations as "corrections" to Staff's adjustments when they are not. In the Company's brief, page 250, the Company stated that, "if the Commission were to use Staff's methodology…then the methodology should at least be corrected." This recommendation was in reference to Staff's inclusion of a onetime credit that the Company had received. Staff's inclusion of the credit in its projection was not an error. It is Staff's position that the credit the Company received should be to the benefit of the ratepayer. Again, on pages 254 and 255, the Company stated, "if the Commission were to use Staff's methodology, however, then the methodology should at least be corrected," regarding General Benefits and Benefit Administration Fees expenses. The Company expressed a grievance with Staff's method accounting for changes in capitalizations percentages that reduce the Company's expense. Staff's method was intentional and with purpose. The Company's increased capitalization of expenses should be reflected in average annual growth models. The Company should not benefit at the expense of the ratepayer by simultaneously receiving a larger rate base and a higher O&M expense projection by excluding the increased capitalization percentage from expense projections. While Staff is cognizant of the adversarial process, the Company misleadingly presented it recommendations for Staff's adjustments as "corrections" when they are not. This goes beyond the attempt to persuade and patently mischaracterizes the Company's suggestions. The Company's brief should be presented in a context, wherever possible, that is clear and understandable to all. The Company should not attempt to mislead the Commission or others, by presenting its recommendations as corrections to errors.

II. Cost of Service, Rate Design and Tariffs

(Citations in Section: DTE's Initial Brief, pp 310—311, 336—337; Staff's Initial Brief, pp 110—151; CEO's Initial Brief, p 18—19; DAAO's Initial Brief, pp 70, 86, 88; MEIU's Initial Brief, pp 31—34, 36—40; EVGo's Initial Brief, pp 6—9, p 80; Walmart's Initial Brief, pp 9—10; Electrify America's Initial Brief, pp 3—6; GLREA's Initial Brief, p 31; ABATE's Initial Brief, pp 48—50; MNSC's Initial Brief, pp 174—177; Ann Arbor's Initial Brief, pp 16—17;

Exhibits A-26, Schedule P2; MEC-127,

Willis, 6 TR 2593, (Rebuttal) 2640, 2754; Isakson, 6 TR 4913; Krause, 6 TR 5203; Rafson, 6 TR 4865—79; Braunschweig Cross, 6 TR 3568—3570; Bennett, 6 TR 1968; Revere, 6 TR 4982; Makhijani, 6 TR 4611.

MPSC Case No. U-21291, Staff's Exceptions, p 4;

MCL 460.1177(2);

26 U.S. Code § 30C;

In re DTE Electric 2022 Rate Case, MPSC 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 Commission's Own Motion, MPSC Case No U-20757, F#0524, Staff Report;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, PFD, p 840;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297,12/1/2023 Order, pp 341—342;

In re Commission's Own Motion, MPSC Case No U-21569.

A. Staff submits this overview of its replies to arguments on cost of service (COS) and rate design.

Staff replies to certain arguments regarding COS and rate design. Staff presented its positions on various cost of service, rate design, and tariff topics in its initial brief. (Staff's Initial Brief, pp 110–151.) As expressed throughout this reply brief, Staff does not seek to unnecessarily repeat arguments from its initial brief. Staff selectively responds to specific positions from the parties' initial briefs in the subsections below that warrant response. However, unless otherwise expressly stated in this reply brief, Staff maintains all its positions in its initial brief.

B. The Commission should approve Staff's proposal to allocate purchased power capacity cost using 4 CP (coincident-peak) 75/0/25.

Staff disagrees with the Association of Businesses Advocating for Tariff Equity's (ABATE's) claim that DTE's purchased capacity costs are largely related to renewable energy assets and that the Company's PA 295 renewable resources are "largely fixed cost assets." (ABATE's Initial Brief, pp 48—50.) ABATE also states that "regardless of customer energy consumption, or even energy generation, 89% of these costs would remain fixed and should be allocated as such." (ABATE's Initial Brief, p 49.) However, renewable resources are *not* all capacity as demonstrated on Exhibit A-26, Schedule P2. On this exhibit the Company uses the fixed and variable components of the transfer price to proportionally split renewable costs between capacity-related and fuel-related. Exhibit A-26, Schedule P2 illustrates that approximately 33.6% of renewable resources are determined to be capacity-related and 66.4% are determined to be fuel-related.

Whether or not some portion of renewable costs are considered to be "fuel" for the offset calculation is not relevant to the portion that is considered capacity related. Staff also points out that fixed costs do not automatically equal capacity costs and that a capacity-related cost does not call for a pure capacity 100% demand allocation. Even if a renewable resource is a fixed cost asset, this does not automatically make that resource completely capacity related. For these reasons and the reasons previously stated in Staff's initial brief, the Commission should approve Staff's proposal to allocate purchased power capacity costs using the 4 CP 75/0/25 method. (Staff's Initial Brief, pp 117—119.)

C. The intent of the SRM true-up has not been shown to be to reconcile amounts paid by a customer.

Staff disagrees with Energy Michigan's (EM's) claim that the true-up of projected and actual net revenues must always be in error, based on the assumption that the intent of the true-up is to adjust amounts paid by customers. (EM's Initial Brief, p 16.) EM has failed to show that is the intent, and such an interpretation would be inconsistent with the plain language of the law, as further discusses in Staff's initial brief. (Staff's Initial Brief, pp 111—12, 115.) For these reasons, the claim should be rejected.

D. The Company's analysis was sufficient to support transitioning customers from Rate D1.6 to D1.11.

The Company provided a bill impact analysis of customers on Rate D1.6, the obsolete residential inverted-block rate that receive the low-income assistance (LIA) credit, transitioning to the standard Rate D1.11. (DTE's Initial Brief, pp 310—311.) Because the Company has data on the rates charged and usage metered by these customers it could examine the exact difference in bills for the same customer on each rate, much like shadow-billing. (Staff's Initial Brief, pp 121—122.) CEO[1] and DAAO[2] argue that further analysis is required before transitioning customers to Rate D1.11 despite agreeing with the Company's conclusion that the majority of Rate D1.6 customers would be better off on Rate D1.11. (CEO's Initial Brief, p 18; DAAO's Initial Brief, p 70.) Staff and the Company disagree. (Staff's Initial Brief, p 123; DTE's Initial Brief, p 311.) The Company also disagreed that further study was warranted because "there is no obvious end point to the analysis" proposed by DAAO. (DTE's Initial Brief, p 311.) Staff concurs with the Company on this additional disagreement. For example, DAAO and CEO never specify at what level of bill impact or amount of study it would be appropriate to transition a customer to Rate D1.11. Of the 42% of customers that would receive a higher bill on Rate D1.11 without any usage changes, the average difference is 0.52% according to the Company's analysis. (Willis, 6 TR 2593.)

For these reasons, the Commission should approve the Company's proposal to transition customers from Rate D1.6 to Rate D1.11 or another rate of their choosing for which they are eligible.

[1] The Ecology Center, the Environmental Law & Policy Center (ELPC), and Vote Solar are collectively known as the Clean Energy Organizations (CEO.)

[2] Soulardarity and We Want Green, Too are known collectively as the Detroit Area Advocacy Organizations (DAAO).

E. Staff responds to arguments regarding EVs and chargers.

1. MEIU is mistaken in applying Staff's residential Contribution in Aid of Construction (CIAC) waiver reasoning to Direct Current Fast Chargers (DCFCs).

MEIU[3] in its initial brief (pp 31—34) advocates for CIAC waivers for EV charging and claims that Staff witness Kevin Krause's logic for residential customer waivers applies to commercial customers. DTE, as supported by its witnesses Aaron Willis and Pina Bennett, proposes in its initial brief at page 284 to eliminate the CIAC waiver for all L2 and public DCFCs. (Bennett, 6 TR 1968; Willis, 6 TR 2754.) Staff discusses in its initial brief waivers for CIAC for residential EV charging and opines how this may be extended to commercial charging with further discussion. (Staff's Initial Brief, pp 133—134.) To clarify, Staff witness Krause did not intend to imply that this waiver should extend to fast charging DCFCs at commercial locations. (Krause, 6 TR 5206—07.)

Staff maintains the rationale expressed by its witness Nicholas Revere, who stated, "Electrify America witness Davis also expresses a desire for "destination" DCFCs to not be excluded from receiving rebates as proposed by the Company" because "the effect would be to "artificially" limit DCFC sites." (Revere, 6 TR 4982.) Witness Revere correctly stated that "the limit is not 'artificial'; it is removing rebates for sites that are not necessary to achieve the goal of a skeleton network to

[3] Michigan Energy Innovation Business Council, the Institute for Energy Innovation and Advanced Energy United are collectively referred to as MEIU.

reduce range anxiety." (*Id.*) Staff witnesses Revere and Krause both do not support extending the waivers to commercial users and DCFCs.

In an EV future every residential customer will likely need EV charging, leading to it being part of standard service (at a reasonable level of charging), which makes the waivers appropriate with certain limitations. (Krause, 6 TR 5206—5207.) The same rationale is not necessarily true for every commercial customer, limits may differ for them, if the waiver is extended at a future date, and the rationale is certainly not applicable to any given DCFC owner. Staff's reasoning for considering residential CIAC waivers appropriate should not be extended to DCFCs, and MEIU's position should be rejected.

2. The demand charge holiday for fast charging should not be extended, as there is no evidence that the tariff will inhibit deployment.

Staff in its initial brief recommends that the demand charge holiday as currently approved remain in place. (Staff's Initial brief, pp 132—133.) MEIU argues in its initial brief that the holiday should stay in place until market maturity due to reaching an equilibrium of utilization. (MEIU's Initial Brief, pp 36—40.) EVGo (EVGo's Initial Brief, pp 6—9), Electrify America (Electrify America's Initial Brief, pp 3—6), and Walmart (Walmart's Initial Brief, pp 9—10) also discuss extending the demand charge holiday for various reasons, but in Walmart's case it also proposes that a separate fast charging rate be proposed in a future case, a proposal not supported by EVGo or Electrify America. The Company agrees that the demand charge holiday should not be extended. The Company's brief states, "Witnesses Sherman and Shaw [sic][4] did not provide any particular evidence that a further extension is necessary", and "there is no evidence that the tariff is inhibiting the deployment of fast chargers." (Company's Initial Brief, p 291.)

Staff stated in its initial brief "that charging less than the cost-of-service for DCFC will result in too much fast charging." (Staff's Initial Brief, p 133.) Project this into market maturity and this will mean that the oversupply of fast charging will lead to utilizations for DCFCs that are lower than they otherwise would be. The adjustment to cost-of-service rates for fast charging should be made before market maturity to avoid this issue. MEIU's position that the demand charge holiday should extend into market maturity should be rejected.

Several parties comment on "instability" as a result of the currently approved demand charge waiver. Walmart is concerned that companies will be deterred due to rate instability. (Walmart's Initial Brief, p 10.) EVGo suggests that "the 'uncertainty' at issue is over the charges the customer will pay, not over the mechanics of the DTE's tariffs." (EVGo's Initial Brief, p 8.) Similarly, Electrify America states "[s]witching from one rate to another, and therefore completely shifting one of the major costs that a DCFC site has to pay as part of its operations, can quite easily be described as instability." (Electrify America's Initial Brief, p 6.) EVGo also states, "While a two-year exemption from demand charges might be helpful in the near-term, the timelines associated with DCFC site development and

[4] It appears that the Company is referencing the testimony of witness Jigar Shah (6 TR 4786—87(Revised)) from Electrify America and that the spelling is a typo.

investment justification are far longer, and therefore two years of demand charge relief is not sufficient to alleviate the customer's uncertainty." (EVGo's Initial Brief, p 8.) To Staff, it appears what these parties want is not actually rate certainty, but a certainty of a bill without demand charges and any attendant increase for a low-utilization charger. In Staff's opinion, these arguments are not appropriate justification to change the currently approved demand holiday that results in customers ending up on the rate they should be on, and the arguments should be rejected.

The Commission, in its order in U-21297, accepted the recommendation for changes in the demand charge holiday, on the basis stated in the PFD. *In re DTE Electric 2023 Rate Case*, MPSC Case No. U-21297,12/1/2023 Order, pp 341—342. The PFD stated that the ALJ "declines the invitation by MEIU and Walmart to make the temporary demand charge holiday permanent because such a step appears inconsistent with the principle that rates should reflect cost of service." MPSC Case No. U-21297, PFD, p 840. As Staff presented in its initial brief, reiterates in this reply brief, and as supported by the Commission's Order in U-21297, the position that the demand charge holiday should be extended or made permanent should be rejected.

This leaves the issue of a potential future rate specifically for EV fast charging. Staff recommends that any future DCFC rate is informed by the cost to serve those customers, consistent with the Commission's previous decision.

3. The recently announced federal 30C tax credit can assist in filling any DCFC funding "gaps."

The Internal Revenue Service (IRS) recently announced rules for implementation of the Alternative Fuel Vehicle Refueling Property Credit, also known as Section 30C. 26 U.S. Code § 30C. The rules provide for federal assistance for EV charging infrastructure in rural and low-income areas subject to other requirements. These funds are in addition to NEVI funding. Publication 6028 discusses tax credits that businesses may obtain for installing charging stations, up to $100,000 per station.

The rules were not released in time to allow parties to discuss them on the record in this case; however, consideration of these tax credits should be allowed in the context of this proceeding, as they have been made public and the parties should be aware of them. Staff recommends that the Commission consider the provisions of the Section 30C tax credit while making decision on spending for EV charging infrastructure in the instant case.

F. The replies to DAAO's arguments regarding Community Solar (CS).

Staff points out in its initial brief that CS savings that have been presented are not based on Michigan costs nor compensation structures. (Staff's Initial Brief, pp 134—135.) The DAAO in its initial brief states, "It is true that these figures are based on estimates and not guarantees of bill savings, but they show what could be possible with the right kinds of investments under the right policy and legal constructs." (DAAO's Initial Brief, p 38.)

Staff takes issue with the use of the word “right”. DAAO’s use of “right” could be read to imply that the correct compensation is the compensation that would lead to bill savings, instead of reflecting the cost or value of service, which may or may not actually provide bill savings. The outcome should be dependent on the rate, not the rate on the outcome. As supported here and in Staff’s initial brief. (Staff’s Initial Brief, pp 134—135.) Staff recommends that the bill savings be determined by setting the appropriate, cost-based, compensation and the actual costs to install the community solar systems.

G. Staff responds to initial briefs with respect to microgrids.

1. Microgrid pilots should be concluded and evaluated before moving forward with more microgrids

The Great Lakes Renewable Energy Association (GLREA) states that “the Commission should allow, and encourage, the development of nanogrids and microgrids.” (GLREA’s Initial Brief, p 31.) Similarly, the “CEO envision a grid of the future, which is decentralized, effectively uses DERs to provide critical grid services.” (CEO’s Initial Brief, p 19.) CEO goes on to say how microgrids are part of that future. (*Id.*, p 20.) DAAO dedicates an entire section of their brief to microgrids, titled *The Commission Should Require DTE to Take Concrete Action to Prepare for the Development of Microgrids*. (DAAO’s Initial Brief, pp 81—89.) DTE states in its initial brief that single customer nanogrids are already possible under current tariffs, and that “[t]here are legal and regulatory concerns, however, with witness Rafson’s further suggestions that include service between multiple individual customers, islanded groups of customers, and 'submeters' across neighborhoods." (DTE's Initial Brief, p 336.) DTE also indicates that GLREA witness Robert Rafson essentially poses questions surrounding what is a 'utility' and the nature of Michigan utility regulation. (DTE's Initial Brief, p 337.) DTE suggests various definitions of what a utility has been held to be in a regulatory framework in its footnotes at page 337, which is essentially an entity that furnishes energy to Michigan customers, not customers servicing each other. DTE cites its witness Aaron Willis' testimony for the proposition that witness Rafson's proposal exceeds the current definition of utility. (Rafson, 6 TR 4865—79; Willis, 6 TR 2640.)

Staff responds that the microgrid pilots that are already underway should be carefully evaluated. (Staff's Initial Brief, p 132.) Staff also acknowledges the problems that are caused when microgrids move from utility ownership to third party ownership. Staff in rebuttal testimony mentioned both that customer to customer power sales could be considered wheeling and that third party wires constitute providing a distribution service. (Krause, 6 TR 5203.) For the reasons provided here, as well as in its initial brief, Staff recommends the Commission move carefully with regard to microgrid development and await pilot results before proceeding further.

2. Microgrids should not include fossil generation.

DAAO states, "Microgrids can utilize various energy sources, including fossil fuels like diesel generators as well as renewable sources like solar panels paired with battery storage systems" (DAAO's Initial Brief, p 81). DAAO also later states, “Importantly, these benefits align with Michigan's goal to achieve net-zero greenhouse gas emissions by 2050, which necessitates the complete elimination of fossil fuels for electricity generation.” (*Id.*, p 84.) At least one of the projects DAAO supports building includes diesel generation. (Makhijani, 6 TR 4611.) Staff recommends that if microgrids are built, they should not include fossil generation. (Staff’s Initial Brief, pp 130—131.) For the reasons provided in its initial brief as well as rebuttal testimony, Staff recommends that microgrid projects, if approved, not include fossil generation as it would be contrary to the State of Michigan’s policy goals referenced by DAAO.

3. A microgrid tariff is not necessary at this time

DAAO recommends the Commission “[o]rder DTE and other utilities to revise their existing tariffs or develop a new tariff specifically for microgrids.” (DAAO’s Initial Brief, p 88.) The tariffs of other utilities are outside the scope of this proceeding. Staff mentions several tariffs in DTE’s rate book that may apply to microgrids. (Staff’s Initial Brief, p 131.) Furthermore, in terms of existing tariffs, DAAO provides no evidence regarding what tariffs should be revised, let alone how or why they should be revised. In terms of a new microgrid tariff there is no proposal to evaluate. Due to the reasons supplied here and in its initial brief, Staff recommends that no action be taken at this time with regard to microgrid tariffs.

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

DAAO states "[t]hose who would benefit from these microgrids would start to receive the kind of service to which they are entitled and for which they have been paying but have not been receiving; they should not be required to pay for or pay more for a microgrid that benefits them." (DAAO's Initial Brief, p 86.) Staff does not entirely agree. Customers do deserve to have reasonable levels of reliability, and actions to achieve this should be taken. That does not mean that the action taken needs to include microgrids. Staff recommends, as supported by its initial brief, that microgrid users should be required to pay the costs appropriate to microgrid service. (Staff's Initial Brief, pp 131—32.)

H. The Commission should reject NRDC-MEC's and other Intervenors' proposals to modify the Low-Income Assistance Credit (LIA), Percentage of Income Payment Plan (PIPP), and energy affordability proposals in this case.

In its recommendation for the Commission to leapfrog the work currently being undertaken by the AAA subcommittee of the EAAC, the NRDC-MEC[5] points to the ALJ's LIA credit increase recommendation in DTE Gas Company's ongoing rate case, MPSC Case No. U-21291, but fails to account for important context surrounding that recommendation. NRDC-MEC appears to prematurely assume

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[5] Roger Colton testified on behalf of NRDC-MEC. MNSC authors the brief on behalf of several entities but refers to separate witnesses therein. MNSC refers to the collective Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and the Citizens Utility Board of Michigan.

that the Commission will agree with the PFD in Case No. U-21291. NRDC-MEC states that in MPSC Case No. U-21291 Staff also opposed a LIA credit increase similar to Staff's position in this case, but that the ALJ rejected Staff's position in favor of providing immediate bill relief. And, NRD MEC states that as such, Staff's opposition to the credit increase in this case should be rejected for similar reasons to what the PFD states. (NRDC-MEC/MNSC's Initial Brief, pp 174—175.) NRDC-MEC's argument fails when taking into account the relevant context of Staff's continued objection to the increase. As stated in Staff's exceptions to the PFD in that case, "it is improper to go against the Commission's directive to consider the EAAC-AAA evaluation by determining a program is effective without supporting data and to adopt changes to a program that is currently under analysis." (MPSC Case No. U-21291, Staff's Exceptions, p 4.) The same reasoning applies in this case.

On the one hand, the Commission directed the subcommittee to investigate and evaluate this issue, yet the arguments in support of an immediate credit increase are, simply put, a rush to judgment and a recommendation to dustbin the work of the subcommittee, which, again, is undertaking this work at the direction of the Commission. A reminder should not be needed, nevertheless, the Commission stated in MPSC Case No. U-20836, "the Commission agrees with the ALJ that the *EAAC is in the best position* to assess the issues of the enrollment assignment and caps as well as potential revisions to the LIA credit [...] the Commission directs the EAAC to initiate, according to a format and schedule set by the collaborative, a stakeholder discussion of the company's report on the enrollment of customers in the LIA credit program and submit a report and recommendations to the Commission." (MPSC Case No. U-20836, 11/18/22 Order, p. 407, Emphasis added.)

It also bears emphasis that in DTE's pending gas rate case, No. U-21291, Staff stated in its exceptions that its silence on DTE witness Sparks' claimed best use-case of the credits was because Staff's position is that these issues are, appropriately, being addressed elsewhere *at the Commission's direction.* (MPSC Case No, U-21291, MPSC Staff's Exceptions to the PFD, p 4) Staff maintains in this case as it did in Case No. 21291 that collaborative discussions will lead to the most informed, comprehensive positions and decisions on this matter. As such, Staff recommends the Commission allow this work to continue. (*Id.*)

The NRDC-MEC also asserts that the "workgroup process" will result only in non-binding Staff recommendations and characterizes this process implying that anything that results from this process would be of little value. (NRDC-MEC/MNSC's Initial Brief, pp 175—176.) As part of this argument, NRDC-MEC points to the idea that the subcommittee is an informal group that "operates without governing documents." *Id.* However, despite the AAA subcommittee operating in a form not preferred by NRDC-MEC, the MEC's own Exhibit MEC-127, p 5 explains that the subcommittee operates according to:

> a guiding statement, guiding principles, and commission directives. Please see slides 4-5 in the link to the September 9, 2021 presentation listed above for the statement and principles and slide 4 of the August 12, 2021 presentation and slides 5-11 of the April 18, 2023 presentation to view subcommittee charges to date, which have been assigned to the AAA by either the Commission directly or to the EAAC as a whole (and then assigned to the AAA by EAAC leadership) through various cases. See the attached document titled "Commission

> orders relating to EAAC 2021 2022" that Staff created to collect a list of cases that assigned work to the EAAC, which Staff then used to propose the current AAA (and other EAAC subcommittees') charge in its 3/16/23 report to the Commission and the Commission approved the current AAA charge in its 12/21/23 order.

Therefore, as indicated by this exhibit, despite the NRDC-MEC's attempt to portray the work being done by this subcommittee as of little importance, its form of "governance" has little to do with the work being undertaken. Furthermore, the NRDC-MEC attempts to portray the lack of Staff witness Braunschweig's prescience of the Commission's ultimate decision regarding energy assistance reform as some sort of indication that the subcommittee work should be disregarded in favor of immediate bill assistance. (NRDC-MEC/MNSC's Initial Brief, p 176.) However, Staff witness Braunschweig cannot know precisely how energy assistance reform may occur, as the Commission has not expressed its intention for how it will initiate and organize this process administratively and regulatorily. (Braunschweig Cross, 6 TR 3568.) The work of the AAA is directed by Commission orders. Staff cannot speak on behalf of the Company nor the Commission. Staff requested that energy assistance reform recommendations be included in the utility PIPP reports but ultimately cannot control what the utilities will provide. Similarly, while Staff thinks the Commission could likely initiate the PIPP reporting process in a certain way based on its past actions in the U-20757 docket, Staff cannot speak on behalf of the Commission. For these reasons, the Commission should reject NRDC-MEC's mischaracterization of the AAA subcommittee and the regulatory process/authority.

Furthermore, while the NRDC-MEC argues that "the AAA does not make decisions or even recommendations," Staff points to MPSC Case No U-20757, F#0524, Staff Report, where it is clearly shown that, in fact, it does. (*See* pp 15—23 for such recommendations.) Furthermore, Staff emphasizes that while the subcommittee makes recommendations, it is the Commission that ultimately makes final decisions on any recommendations through the orders it issues.

Next, NRDC-MEC argues "[i]n discovery, Staff could identify no proposals, reforms, or changes discussed at AAA meetings that have subsequently become included in DTE Electric tariffs or rates." (NRDC-MEC/MNSC's Initial Brief, p 176.) Staff points out that the lack of tariff modification does not indicate that work has not been accomplished or recommendations have not been made for the Commission's consideration and action. Not everything the Commission orders is reflected in tariffs and not every recommendation in the present case or the AAA recommendations are within the Commission's authority, which it derives from legislation. For these reasons, the Commission should disregard NRDC-MEC's mischaracterization of the AAA subcommittee.

NRDC-MEC erroneously suggests stagnation on the part of the subcommittee, stating "three years have passed since the AAA subcommittee first convened, and still DTE's LIA program remains the same." (NRDC-MEC/MNSC's Initial Brief, p 177.) As Staff witness Braunschweig made clear in direct testimony, rebuttal testimony, and cross examination, and the discovery response on page 5 of MEC-NRDC Exhibit 127, the AAA subcommittee work is directed by Commission orders. The EAAC was not tasked with review of the LIA until the November 18, 2022 Order in MPSC Case No. U-20836, after which the AAA began work to analyze the credit in April of 2023 (*See* MEC-127, p 2, April 18, 2023 presentation/recording) and the review was expanded to encompass both the PIPP and fulfillment of MCL 460.11(2) in the December 21, 2023 order in MPSC Case No. U-20757. Additionally, there are good reasons for the LIA pilot not to be changed in the instant case as expressed in Staff's initial brief. For these reasons, the Commission should disregard NRDC-MEC's mischaracterization of the AAA subcommittee.

Furthermore, both NRDC-MEC and DAAO engage in speculative arguments regarding the timeline, or timeframe of the work involving the AAA subcommittee to argue that the LIA credit issue will languish without immediate action. (NRDC-MEC/MNSC's Initial Brief, p 177; DAAO's Initial Brief, p 41.) Staff notes that when the Commission issues orders on the credit, the utilities must comply with those orders. This is not optional. Furthermore, there is no evidence presented by either party that the remainder of the process will take an inordinate amount of time. Staff witness Braunschweig explained that future proceedings to implement changes to assistance programs would be *likely*, but it is ultimately up to the Commission how that is handled. (Braunschweig Cross, 6 TR 3570.)

As stated previously, the Commission determines the expediency of the assistance reform process by use of its regulatory authority. For these reasons and those cited in Staff's initial brief, the Commission should allow energy assistance restructuring analysis and recommendations to continue in the AAA subcommittee until it completes its directives.

Lastly, DAAO expressed confusion about which customers received RIA and which received LIA credits in its initial brief, in that some LIA customers are LSP (the Company's MEAP-funded affordable payment plan) customers, some are seniors, sometimes the Company gives the LIA credit to customers that call-in and more generally, DAAO takes issue with the lack of transparency in the Company's decision-making process. (DAAO's Initial Brief, p 27.)

Staff's proposed LIA tariff language partially clears up this confusion in which the proposed LIA tariff language states that the RIA and LIA credits cannot be taken together and that the eligibility criteria is in line with the RIA eligibility along with the Company's affordable payment plan. (Staff's Initial Brief, p 129.) The language, however, does not explicitly clarify which customers will receive the credit, and Staff cannot find a reference from past cases that gave the Company the authority to select which customers received the LIA credit.

The currently-approved tariff language on the Eighth Revised Sheet No. D-12.01 of the DTE Electric tariff book simply states that "Customers who select this pilot rate must qualify for the Residential Service rate," which gives the impression that customers can request or choose to be on the rate schedule. A corresponding issue was raised by Staff in DTE Electric rate case No. U-20836, in which Staff proposed to not allow the Company to have discretion to give the credit to whomever it chose. (MPSC Case No. U-20836 11/18/2022 Order, p 403.) The

Commission order disagreed with Staff's proposal, and the Commission directed analysis of the LIA program cap and enrollment assignment to the EAAC. (MPSC Case No. U-20836, 11/18/2022 Order, p 407.) This is part of the current analysis being performed by the EAAC's AAA subcommittee that Staff referenced in its direct and rebuttal testimony.

I. Several of Energy Michigan's (EM) additional claims regarding the State Reliability Mechanism (SRM) should be rejected.

While Staff responded to most of the arguments made by EM regarding the SRM in its initial brief (Staff's Initial Brief, pp 111—116, 139—142), and stands by those arguments, certain claims made by EM in its initial brief require additional response.

EM claims that, as the MISO capacity auction is now seasonal, the cost is also seasonal. (EM's Initial Brief, p 9.) Staff addressed how the idea that the auction sets the price of capacity is incorrect in its initial brief and is instead based on the cost of the resources used to meet the Company's capacity obligation. (Staff's Initial Brief, pp 139—142), but the implications of this extend to the seasonal cost claims made by EM. To the extent that a company-owned or -contracted resource is the basis for meeting MISO's requirements, that resource does not exist only in certain seasons, nor has the capacity-related cost or provision of capacity been shown to change by season. Therefore, it has not been shown that a change to the current capacity charge method is necessary as a result of the MISO Seasonal capacity construct. While Staff agrees the issue is worth further examination, because there is no showing that a change is appropriate, the Commission should reject this recommendation.

EM also claims that Staff's position on the ACP not being the cost of capacity is somehow related to a misunderstanding of the MISO tariff. (EM's Initial Brief, p 14.) Staff disagrees. As the cost to meet reliability requirements (as opposed to the imposition of the requirements themselves) is only tangentially related to MISO at all, let alone its tariffs, no such misunderstanding could have the effect claimed by EM. Even if the tariffs somehow claimed the cost to meet the requirements was the ACP, that would not reflect reality as shown by Staff. For this reason, the claim should be rejected.

EM further claims that Staff believes "[t]he cost to meet MISO's capacity obligations is really the cost in a retail customer's rate after the SRM Capacity Charge is allocated across retail rates" rather than the cost incurred by the utility. (EM's Initial Brief, pp 13—14.) This is not an accurate description of Staff's belief or position. Staff clearly states that the cost to the utility is the capacity portion cost of acquiring the generation supplying the capacity, as referenced here repeatedly. However, the portion of that cost any given customer is responsible for varies based on their contribution to that cost, which is what the cost-of-service study that allocates those capacity costs to the classes is intended to determine, as Staff notes was properly recognized by the Commission in its initial brief. (Staff's Initial Brief, pp 140—141.) For these reasons, EM's claim should be rejected.

J. Several intervenor claims from MEIBC, MEIU, EVGo, Ann Arbor, and Electrify America regarding EV should be rejected.

While Staff responded to the majority of the Intervenors' EV claims in its initial brief with respect to EV, there are a number of issues that require further response.

MEIU claims Staff witness Revere "attempts to undermine this concept of net benefit from new load," providing an analogy it claims to show this is the case. (MEIU's Initial Brief, pp 15—18.) First, this lengthy analogy is not supported by the record. Second, the analogy has a number of issues Staff will address; to the extent the Commission considers MEIU's analogy, even though unsupported by the record, the Commission should also consider the following Staff response. A simplified description of the analogy is that three roommates would be irrational not to accept a fourth roommate for their open bedroom as long as that roommate covers the marginal costs of joining the household, with any contribution to rent effectively being a bonus.

The first issue with the analogy is that the existing roommates would effectively be the customers of the utility, so ascribing to them the ability to determine the amount charged to the additional roommate breaks the analogy. The Company (and by extension the Commission deciding on the Company's programs) would act in this analogy as the landlord. Therefore, the analogy is better understood as the roommates renting only the rooms, with the landlord having the ability to allow another roommate to rent the fourth bedroom. The landlord would have the ability to determine what price to charge for rent for the fourth bedroom, not the current residents.

The landlord, if a perfectly rational economic actor under the original analogy, should be willing to accept any amount above zero for rent above utilities, as the outcome would be better than zero. This and all further discussion of the analogy will assume any newly added roommate will cover the utilities, the "marginal" cost of their addition, but that those costs are actually incurred by the landlord, in order to give proper meaning to marginal cost consistent with the original analogy. However, the landlord also has the incentive to get as much rent as possible for the fourth bedroom. Therefore, it would not be rational for the landlord to rent the bedroom for less than someone is willing to pay for it. In order to assume that accepting rent at anything greater than zero would be a rational decision, rather than the prevailing market rate presumably charged to the first three roommates, one would have to assume either that any remaining potential roommates place less value on the dwelling than the initial three (i.e. their willingness to pay is lower as their expected benefit is lower), or that the market for dwelling is saturated or collapsed. Let us assume the former. In such a case, the landlord would still rationally charge the highest amount they could and still fill the room. Let's assume that this amount is half of the $800 the original roommates are paying; put differently, no potential additional roommate is willing to pay more than $400 to rent the room, and therefore the landlord would rent the room at $400.

It is helpful to at this juncture to discuss the interaction of the economic concepts of marginal and fixed costs, demand, and how the application of these interactions and concepts differs between the theoretical "perfectly competitive" market and a monopolistic market. First, the simplified or generally assumed shape of a marginal cost curve is a hook; it declines at first, levels, and then increases to a relatively smooth incline. This shows that the marginal cost first declines with additional production and then begins and continues to rise. This is also known as the "supply curve." In a perfectly competitive market, fixed costs are effectively ignored as in the example, as for the market to even exist they need to be covered; put differently, at the relevant portion of the supply curve the average cost (that which includes all costs, both fixed and marginal, divided by units of production) is assumed to be lower than the marginal cost (a topic we shall return to when we reach the discussion of the monopoly market). No rational economic actor expends the fixed costs of production without assuming they will end up being covered by sales of the product.

The demand curve represents the relative "willingness to pay", or the expected benefit a consumer of the product would receive, for all relevant units of production. The simplified or generally assumed shape of this curve is a line with a constant declining slope, which can be interpreted in a number of ways. For the purpose of application to the analogy, it will mean that each potential inhabitant places a different value on the bedrooms offered by the landlord, and they are ranked in order from highest value placed to lowest.

Equilibrium in a perfect market occurs where the supply and demand curves meet. This is the point at which the amount a consumer is willing to pay for that unit of production is equal to the cost of producing it. Producing an additional unit would cost more than someone would pay for it, and producing fewer units would be leaving money on the table. Crucially, in a perfectly competitive market, all consumers are assumed to be offered the same price, because there are a number of competing firms offering the same, homogenous product (though it is also worth noting people tend to dislike paying different amounts for the same product as a matter of basic fairness). Even though some consumers would be willing to pay more for the product, they are able to purchase it at the marginal price from one of the many producers.

The amount of total willingness to pay that is above the cost of the product is known as the "consumer surplus", or the amount of benefit above cost gained by consumers as a whole. The amount of total money charged for all products sold that is above the total marginal cost to produce them is the "producer surplus."

There are ways that a producer can attempt to convert some of the consumer surplus into producer surplus (i.e. take some of the gained benefit of the market from consumers for themselves). The one most relevant to the analogy is "discriminatory pricing" or charging different prices to different consumers based on their relative willingness to pay. In the analogy above, this is effectively what is occurring when the landlord charges $800 to the first three roommates and $400 to the fourth. Assuming $400 is the equilibrium price, the landlord has captured

$1200 of consumer surplus. Again, this does not occur in a perfectly competitive market, though there are some situations in which it may occur in *generally* competitive markets, it is unnecessary to explore here.

Again, the assumption that marginal cost exceeds average cost at the point of equilibrium is important, as if it does not that would mean the market would not exist (at least as a perfectly competitive one), as a producer would never incur the fixed costs knowing they could not be covered by the price and volume that would exist. For the purposes of the analogy, this means that the fixed cost of the building must be less than the rent received minus the marginal cost.

A simplified explanation of what is known as a "natural monopoly" is a market in which the marginal cost is *below* the average cost on the relevant portion of the demand curve (i.e. the point at which equilibrium would exist in a perfectly competitive market), meaning the fixed costs would not be covered at competitive equilibrium. For such a market to exist, a producer would have to charge above the marginal price in order for the market to even exist (more specifically, the point at which marginal revenue equals marginal cost with the assumption it is higher than average cost, but Staff digresses). Utilities are often considered natural monopolies, as the economically-considered "fixed" costs associated with utility service are relatively high, with marginal costs relatively low, which is why utility prices are above marginal costs. Obviously, a vast simplification, and not without controversy particularly with regard to generation, but useful to note.

Returning to the modified analogy, another aspect of utility service is that the utility has an obligation to serve within its territory. It is expected to serve anyone who desires service. This concept will be extended to the analogy shortly. Another aspect of utility service is that its investments tend to be "lumpy." In other words, increments of what might be considered "fixed" costs are quite large (to achieve cost efficiency), and can therefore serve a lot of customers once incurred. This extends wonderfully to the analogy; we can simply assume that the most cost-effective way for additional tenants to be served (and we must now assume that they *have* to be to maintain the analogy for a utility) is in buildings of four bedrooms, just like the first building. Assuming the first building is now full, whatever the price the landlord charged the additional tenant, another tenant needing or desiring a bedroom would require the construction of a new building of four units. The "marginal cost" of adding this new tenant is effectively the cost of additional utilities plus the entire cost of constructing the new building, though the next three tenants would not cause this cost to be incurred.

The combination of these lumpy investments and the cost structure of utilities (i.e. that of a natural monopoly) underlines how little the concept of marginal cost applies to utility pricing, as discussed by Staff witness Revere. This combination of factors, as well as how the concept of fairness in pricing should apply to utilities, is one of the major reasons embedded cost rate regulation exists at all. Rather than use the concept of marginal cost, which is of little value given the realities, customers served in a like manner are charged like rates based on the average costs to serve that type of customer, and only divided into separate groups when their contribution to the incurrence of cost is different in a way beyond the lumpy way utility investment occurs. To fully follow through the analogy appropriately would lead to the argument that only the first customer who causes a utility to make an investment should pay for that investment, and every other customer who can be served by that investment should pay nothing. This, in the largest context, is fundamentally unfair. MEIU's analogy breaks down when examined with a basic understanding of utility regulation and economic principles and should therefore be disregarded.

MEIU itself extends the idea of how marginal cost being applied to the way a utility charges customers can be considered inappropriate or unfair (though mistakenly) when discussing whether or not the Company's CIAC principles apply to customers attaching a charger. (MEIU's Initial Brief, pp 32—34.) While Staff agrees that the principle applies to residential charging at a certain level, as such charging will effectively become a standard part of service for such customers in an EV future, it is also appropriate to charge customers who are receiving a service that differs from that provided to otherwise similar customers (such as businesses installing a DCFC, or a roommate requiring two bedrooms, one that is substantially larger than standard, or a private bathroom to further extend the analogy) for that difference in service. This issue is further discussed elsewhere in this brief.

While Staff addressed its proposal regarding individual cost-benefit analyses for fleet EVs in its initial brief (Staff's Initial Brief, pp 135—136), MEIU claims that certain benefits can't be considered in such site-specific CBAs. (MEIU's Initial Brief p 19.) As this claim is unsupported by any reason such benefits could not be considered, and Staff's position on the appropriate consideration of such benefits, this claim should be rejected.

EVGo claims that Staff witness Revere "never explains why on-route locations would be 'most beneficial to ratepayers.'" (EVGo's Initial Brief, p 17.) This is inaccurate. As stated by Staff witness Revere in response to similar arguments to EVGo's made by Electrify America, on route chargers (but not destination chargers) "achieve the goal of a skeleton network to reduce range anxiety to gain the benefit of home charging, which assists in achieving the actual goal," that actual goal being maximizing the net benefit to ratepayers. 6 TR 4982. For this reason the claim should be rejected.

EVGo claims that "the record is clear that the EV market is growing and programs that provide support for fast charging infrastructure will only serve to further accelerate this growth." (EVGo's Initial Brief, p. 25.) What this claim fails to acknowledge is that using ratepayer funds to accelerate this growth is effectively taking the benefit of the additional EV revenue from ratepayers to accelerate future benefits, which lowers the overall benefit to ratepayers rather than increasing it. For this reason the claim does not support expansion of EV programs.

Ann Arbor claims that the 200% of Federal Poverty Level (FPL) eligibility threshold is "is simply too restrictive to result in the successful deployment of low-income rebates" and basically defines success as "number of rebates processed."

(Ann Arbor's Initial Brief, pp 16—17.) Staff finds this definition of success misplaced. Redefining low-income to mean 300—400% of the FPL does not make the program more successful in any reasonable way; even if it results in more credits being disbursed, they would no longer be provided to actual low-income customers as reasonably defined at 200% of FPL. The logical takeaway from a low disbursement of low-income rebates should not be that the income threshold is too high, it should be that the demand for EVs *does not yet exist at that income level.* For this reason, this claim should be disregarded.

Electrify America claims that the result of the Company's proposed exclusion of destination chargers from rebates "will incentivize DCFC sites that have no amenities, no public restrooms, and no business or other activity for EV drivers to take part in while their vehicles charge." (Electrify America's Initial Brief, p. 13.) As this assertion is completely unsupported on the record, it should be disregarded.

K. Great Lakes Renewable Energy Association's (GLREA) arguments regarding distributed generation (DG) billing and compensation should not be misconstrued.

GLREA discusses how MCL 460.1177(2) and the Commission's decision in U-21569[6] excluding securitization charges from the charges on a customer's bill a DG outflow credit applies to, as well as the Company's application to change its DG tariffs in MPSC Case No. U-21798 consistent with that decision. (GLREA's Initial Brief, pp 16—22.) While Staff is taking no position on the Commission's decision in

[6] On October 10, 2024, the Commission denied GLREA's petition for rehearing in U-21569.

MPSC Case No. U-21569 or the Company's application in MPSC Case No. U-21798 in the instant case, the language used by GLREA seems to conflate and/or confuse the calculation of the DG outflow credit under the Commission's previous decisions on the matter with the charges on the bill that charge is allowed to offset. GLREA repeatedly refers to inclusion of the securitization charge in the calculation of the DG outflow credit. The DG outflow credit calculation only includes the DG outflow credit listed in the Company's tariff for same, as well as the Power Supply Cost Recovery (PSCR) factor. The calculation of the DG credit does not (and should not) include anything else based on the Commission's previous decisions on the matter or the applicable tariffs, so to the extent GLREA intends to modify the calculation of the DG credit as opposed to the charges on the bill it is allowed to offset, that should be rejected. MCL 460.1177(2) reads as follows:

> A distributed generation customer shall be credited by the customer's supplier of electric generation service for the outflow during the billing period. The credit must appear on the bill for the following billing period and be limited to the total charges on that bill. Any excess bill credits not used to offset inflow charges in the next billing period will be carried forward to subsequent billing periods.

It is clear from the plain language of this statute that it is not the calculation of the DG credit itself that is being discussed, but that the DG credit in any billing period cannot be larger than the total bill it is to be applied to, with any amount exceeding what is so applied in that billing period carrying over to the next. The Commission should rule consistent with the plain reading of the statute's language.

III. Return on Equity

(Citations in this Section: MNSC's Corrected Brief, pp 131, 141.

Ufolla, 6 TR 5025; Villadsen, 6 TR 3757; Bandyk, 6 TR 3757; Coppola, 6 TR 3674;

89 FERC ¶ 61,036;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 10/5/2023 PFD;

In re DTE Electric 2023 Rate Case, MPSC Case No. U-21297, 12/1/2023 Order, p 186.)

A. Staff replies to MNSC/CUB-MEC's argument regarding the Risk Premium Model's appropriateness for use in a rate case.

On page 141 of its corrected initial brief, MNSC, inclusive of CUB-MEC[7], states [t]he Risk Premium Model should not be used at all", but the rest of MNSC/CUB-MEC's argument does not support that statement. MNSC/CUB-MEC seems not to have delved into the distinction between Staff's use of the RPM and the use by the Company. MNSC/CUB-MEC states that it does not attempt to delve into every aspect of ROE and relies on Staff, ABATE and the Attorney General to do so. (MNSC's Corrected Brief, p 131.) Staff, therefore, will do so.

[7] As stated previously, MNSC authors the brief on behalf of several entities but refers to separate witnesses therein. See footnote 4 on page 25. Michigan Environmental Council and the Citizens Utility Board of Michigan (MEC-CUB) specifically sponsor witness Bandyk, who addresses ROE for the collective. Whereas, witnesses Jester and Bunch testify on behalf of MNSC as a whole.

MNSC/MEC-CUB focuses on the Company's use of the risk premium model and does not address Staff witness Joseph Ufolla, ABATE witness Christopher Walters, or Attorney General witness Sebastian Coppola's use of the model. Staff testified to the difference in its use of the risk premium model versus the Company's use of that model in the instant case:

> The Company uses a regression analysis risk premium model, while Staff prefers the use of a more traditional risk premium model that is more widely accepted in the ratemaking process. Because the model employs approved ROE instead of earned ROE (like Staff's model), the data set only reaches back to 1990 giving only 34 years of data. For these reasons, Staff maintains its preference for 12 its own Risk Premium models that have a larger data set, and basis in earned ROE. [Ufolla, 6 TR 5025.]

MNSC/CUB-MEC states in its brief, at page 142, that CUB-MEC witness Bandyk testified that the risk premium method introduces the reliance on ROEs set by other regulatory commissions when objective date is preferrable. He also stated that those premiums are already above the market. (Bandyk, 6 TR 3747—48.) But, CUB-MEC's own witness does not state that the risk premium model in general should not be used. He focuses on witness Villadsen's recycling of estimations by other regulatory commissions, stating:

> As the methodology below shows, Dr. Villadsen's recommended ROE is inflated above what would be a fair return due to several overestimated inputs into her DCF and CAPM analysis as well as her use of a Risk Premium model that essentially recycles the overestimations of ROE by other regulatory commissions. [6 TR 3757.]

MNSC/CUB-MEC states, in its corrected initial brief, that FERC rejected the use of the risk premium methodology in Opinion 569 after finding various disadvantages with it; although, MNSC admits that FERC later reversed course in Opinion 569-A.

Both decisions were appealed. On appeal, FERC decided there was insufficient evidence in the record to justify use of the RPM at FERC at this time under section 206 of the Federal Power Act (FPA). FERC reversed the portions of Opinion Nos. 569-A and 569-B that include the Risk Premium model and maintained the other modifications to the Commission's ROE methodology set forth in Opinion No. 569, as modified by Opinion Nos. 569-A and 569-B. [8]

FERC acts under the Federal Power Act and while its opinions may provide guidance and considerations for appropriate models to use in calculating ROE, these opinions are not dispositive. FERC's decision does not bind the Michigan Commission to Opinion 569, which MNSC/MEC-CUB relies on in its corrected initial brief. The D.C. Circuit's remand of Opinion 569 was based on the facts of that case, which are not present in the instant case.

The FERC opinions do not share common facts and circumstances with the instant case. And even if those opinions did have similar facts and circumstances to the instant case, those opinions would still not be binding on the MPSC. As explained in Staff's Initial Brief, this case has a solid record upon which to defend the RPM.

[8] 89 FERC ¶ 61,036.

B. MNSC/CUB-MEC's Risk Premium argument does not apply to Staff's risk premium model, nor to ABATE witness York's or the Attorney General witness Coppola's risk premium models.

Because Staff, the AG, and ABATE, base their Risk Premium analysis on earned ROE (the actual, historic, realized ROEs of utilities), and not approved ROE, the critiques laid out by MNSC/CUB-MEC do not apply to these models. The importance of the Risk Premium Model should not be understated; the Risk Premium method is the only ROE estimate provided by Staff which does not rely on the proxy group. This macro-level analysis in conjunction with the micro-level proxy analyses (observed in the DCF and CAPM) provide a well-rounded and holistic view of the cost of equity.

The Risk Premium Model itself is not unfit, rather it is the Company's use of approved ROE's as part of its Risk Premium Model that is flawed. Approved ROEs rarely take into account purely financial and economic concepts when the ROE is ordered; conversely earned ROE is ultimately determined by market forces. Staff does not dispute the arguments made by MNSC/CUB-MEC against a Risk Premium model which uses approved ROEs. In fact, Staff supports witness Bandyk's statement referring to the Risk Premium Model that "…academic research has shown the reliance on historic **allowed** returns to be distorted from objective methods to determine a reasonable rate, the Commission should disregard the proffered Risk Premium approach." (Emphasis added, Bandyk, 6 TR 3761.) It is clear with respect to witness Bandyk's argument that the proffered Risk Premium approach was made by witness Villadsen. Witness Bandyk states, "Dr. Villadsen's

Risk Premium analysis should be disregarded because it introduces into the calculation of ROE, a process that should be based on objective data as much as possible, the reliance on ROEs set by other regulatory commissions." (Bandyk, 6 TR 3760.)

MNSC/CUB-MEC's initial brief (p 142) also cites to the PFD in the DTE's last electric general rate case, No. U-21297, which states "[t]his PFD also finds that the approach of performing **a risk premium analysis based on a regression of the returns awarded by regulatory commissions** relative to the treasury interest rate is not a compelling analysis." Emphasis added. MPSC Case No. U-21297, PFD, October 5, 2023, p 484.

MNSC/CUB-MEC points out that the ALJ in Case No. 21297 referenced Attorney General witness Sebastian Coppola's testimony where he testified to the same reasons for criticizing the Company's use of the risk premium model in the instant case. (Coppola Direct, 6 TR 3750; MPSC Case No. 21297 PFD, p 484.) MNSC does not fully represent the PFD in case No. 21297.

That PFD did not reject use of the risk premium model but rather the Company's use of that model. The PFD in Case No. 21297 states:

> This PFD finds Mr. Coppola's and Mr. Ufolla's testimony persuasive that DTE's return on equity should be set at 9.8%. These two expert witnesses reached the same conclusion through different analyses, and **these analyses were conventional in nature, consistent with the analyses the Commission has relied on in past cases,** with the exception of Staff's projected CAPM which Mr. Ufolla reasonably discounted. [PFD, p 482.]

Thus, the PFD in Case No. 21297 supports the RPM as used by the Staff and merely rejects the manner in which the Company used the model. MNSC did not take exception to the PFD's ROE in that case. On page 186 of the Order in Case No. 21297, the Commission agreed with the PFD's ROE of 9.8%.

In the instant case, AG witness Sebastian Coppola, again, did not argue against the use of an RPM in general as used by Staff. Indeed, he utilizes and supports the traditional RPM. He repeated his reasons in this case, and those reasons have not changed from his testimony in Case No. 21297, as follows:

> In her testimony, Dr. Villadsen states that she compared authorized ROEs from electric utility rate case decisions to 20-year U.S. Treasury bonds from 1990 to 2023. She ran a regression model with this data and observed that ROE rates have fallen more slowly than treasury bonds. Based on this analysis she concludes that an ROE of 10.5% for electric utilities would be appropriate based on the 20-year forecasted U.S. Treasury rate of approximately 4.30%.[9]
>
> There are several flaws with this analysis. Chief among them is the premise that treasury bond yields are the primary driver in ROE decisions by regulators. It is also not connected to stock market performance or investor expectations of returns on investment. This analysis has no validity as a tool to determine the ROE to be established in rate proceedings. Regulators approach the serious business of establishing a ROE based on many factors and often exercise "gradualism" in the process as well. The Commission should give this analysis no weight in this case. [Case No. 21534, 6 TR 3674.][10]

There is no reason to deviate from the PFD's conclusion in Case No. 21297 that Staff's use of the risk premium analysis was appropriate and that it is a

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[9] The biggest difference from the quote in this case and that in 21297 is that the Company asked for a 10.4% ROE in Case No. 21297.

[10] See the entire quote of witness Coppola's testimony in Case No. 21297 at 6 TR 3750, which was quoted in the PFD for that case, and is almost identical to this quote.

conventional model, if used the way Staff testified, as upheld by the Commission's December 1, 2023 Order. *In re DTE Electric 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p. 186.

IV. Other Issues

A. Staff replies to DAAO's initial brief regarding non-energy benefits.

(Citations in Section: DAAO's Initial Brief, pp 44—47, 95; Makhijani, 6 TR 4581; DTE's Initial Brief, p 323.)

Staff disagrees with DAAO's proposal in its initial brief with respect to non-energy benefits. The DAAO urges the Commission to:

> a. Require the Company to account for these avoided costs explicitly when making proposals, including but not limited to those related to unaffordability and poor reliability; and
>
> b. Consider these avoided costs under similar circumstances.
>
> c. Explicitly account for these avoided costs when considering addressing the issues of unaffordability and poor reliability. [DAAO's Initial Brief, p 95.]

DAAO's proposal is vague and does not allow for reasonable analysis of how considering non energy benefits would be accomplished and what impact it would have on the rate-setting process. DAAO does not suggest a methodology for the Commission to use in considering non-energy benefits when assessing the impacts of unaffordable and unreliable energy and the benefits of proposals to address unaffordability and poor reliability. In addition, DAAO has not provided the Commission with examples of or methodologies for how the Commission can integrate non-energy benefits into decision making for Michigan specific rates or programs.

DAAO agreed that Staff's assertions in brief raise valid concerns including that assigning monetary values to health improvements or housing stability is subjective and can lead to inconsistent results; that information is "scattered and incomplete … underscor[ing] the difficulty of assessing non-energy benefits in the instant case; that Michigan's regulatory framework currently only requires utilities to meet the Utility Resource Cost Test (URCT), which does not include NEBs, in utility EWR portfolios, and that there is no accepted methodology for quantifying or evaluating non-energy benefits … that can be extrapolated to the affordability of rates in electric rate case proceedings in Michigan." (DAAO's Initial Brief, p 47.)

DAAO states that while it is not possible to quantify all of these costs and benefits to a high degree of precision at present, it is relatively straight forward to develop estimates for some of these costs and benefits. (*Id.*, p 44.) DAAO provides an example of such an estimate as $36,000 in societal costs per event for individuals losing housing due to unaffordable energy bills. (*Id.*, pp 44—45.) What is unclear is how costs are reasonably assigned to the increments attributable to high energy bills, when housing, food and medical costs may also be high. This conundrum can be applied to other costs that are considered non-energy benefits such as the avoided costs associated with the absence of emergency room visits, which DAAO witness Arjun Makhijani testified to. (6 TR 4581.)

DAAO states that other public utility commissions consider non-energy benefits. (DAAO's Initial Brief, p 44.) Outside of this assertion being vague as to what this pertains to, it is important to note that Staff could not locate a Public Utility Commission that considers non-energy benefits outside of energy efficiency and demand response proceedings. Indeed DAAO cites the Maryland Public Utility Commission's use of non-energy benefits which are authorized by law to be included in a Total Resource Cost Test and a Societal Cost Benefit test in energy efficiency and demand response programs. Maryland 32 PUA § 7-211(f)(1) and (h)(7). However, the law does not direct the Maryland Public Utilities Commission to use non-energy benefits in the rate making process. In addition, Maryland and the DAAO differ in the definition of non-energy benefits where DAAO states that non-energy benefits span a wider range of benefits than these two tests. (DAAO's Initial Brief pp 43—44.) Therein lies part of the issue. Non-energy benefits are not defined precisely enough to allow for meaningful analysis.

The DAAO has not provided evidence of how the Commission would standardize and consistently use a calculation of non-energy benefits in the rate setting process nor in its decision-making processes in other proceedings.

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

B. Staff replies to MI-MAU regarding street lighting issues.

(Citations in this Section:

MI-MAUI's Initial Brief, p 11, p 41; Ann Arbor's Initial Brief, pp 211, 14; Staff's Initial Brief, p 127; DTE's Initial Brief, p 323;

Isakson, 6 TR 4913; Bellini, 6 TR 3105—06.)

1. MI-MAUI construes retroactive ratemaking incorrectly with respect to Lighting Bill Credits.

MI-MAUI describes the Company's argument that the Commission should "revisit" the decision to disallow $5.8 million in gross plant for LED as an argument for retroactive ratemaking. (MI-MAUI's Initial Brief, p 11.) This is inaccurate and requires additional context because a distinction must be made between how balance sheet items and income statement items are considered in ratemaking. Retroactive ratemaking would be to return to a rate set by a previous Commission decision and alter the recovery of revenue already collected, or not collected, based on that rate (absent some tracking mechanism approved at the same time). The amount rates are based on for an income statement item is the expense or revenue itself, as that is the revenue requirement impact. For a balance sheet item, however, rates are based on the calculated revenue requirement associated with that item: put simply, the return on (overall cost of capital applied the average net balance over the test period) and return of (amount of depreciation expense associated with the item over the test period).

Because the Company is referring specifically to a balance sheet item—a plant account—the Commission certainly may determine it is now appropriate for the Company to recover the going-forward revenue requirement associated with the item without it being retroactive ratemaking. MI-MAUI's inclusion of the plain text definition of retroactive ratemaking is helpful because it refers specifically to "past expenses and costs." (*Id.*) Should the Commission determine that the $5.8M in

LED gross plant is ultimately appropriate to include in rate base due to, for example, newly provided evidence, then it may include recovery of the cost associated with that rate base *going forward*. Retroactive ratemaking in this instance would be determining the revenue requirement amount associated with the disallowance in the previous decision over the previous test period (or length of time over which the approved rates were in effect), *not* including the going-forward revenue requirement and in rates.

Staff does not recommend a specific remedy regarding MI-MAUI or the Company's argument regarding its previous decision to disallow certain LED gross plant, but instead reminds the Commission that it has the authority to approve future rates that include (or exclude) revenue requirements associated with balance sheet items over the test period regardless of previous decisions.

2. Staff supports MI-MAUI's streetlighting conversion credit proposal, but not its proposal to eliminate CIAC for planned LED conversions.

MI-MAUI and Ann Arbor noted that Staff supported their proposal to provide bill credits for customers that previously paid CIAC for LED streetlight conversion, which the Commission should direct the Company to propose in its next case in consultation with intervenors and Staff. (MI-MAUI's Initial Brief, p 41; Ann Arbor's Initial Brief, p 14; Staff's Initial Brief, p 127.) The Company will begin replacing high-pressure sodium light fixtures upon failure with LED luminaires by January 1, 2025 at the latest with no extra charge to the customer. (Bellini, 6 TR 3105—06.)

The Company opposed MI-MAUI's conversion credit proposal because refunding customers' CIAC payments would be inconsistent with Commission-approved policy. (DTE's Initial Brief, p 323.)

Customers choosing to convert to LED prior to the Company's decision to begin replacing failed lamps with LED did so under the condition that LED service was not standard. Now that such service will become standard in 2025, it is reasonable to make those customers whole via a bill credit. (Isakson, 6 TR 4913.) However, because the Company's new policy involves replacing failed lights it is still appropriate to charge CIAC for customers opting for a planned, group conversion to LED service. After 2025, customers choosing to "jump the line" and convert to LED service prior to a no-additional-cost conversion when i lights eventually fail constitutes the same deviation from standard service and should therefore be charged CIAC. These customers should not qualify for a conversion credit either, because they will have known in advance that they will eventually receive LED service at no additional cost. MI-MAUI argues that it would be cheaper for the Company to conduct planned LED conversions rather than reactive conversions, and therefore customers choosing to convert before their lights fail should not pay CIAC. (MI-MAUI's Initial Br, p 43.) Staff argues that if the Company does eventually decide to engage in planned, group LED lighting conversions then no CIAC should be charged, but since that is not the current reality then the current CIAC policy for LED lighting conversion should remain.

For these reasons the Commission should approve MI-MAUI's proposal regarding LED conversion credits for lighting customers that paid CIAC for LED conversion prior to the Company decision to reactively replace failed lights with LED service. The Commission should not waive CIAC fees for customer choosing planned conversion to LED lights unless the Company changes its conversion strategy to include planned conversions.

V. Conclusion

Staff submits that its recommendations contained in this reply brief, as well as its testimony, exhibits, and initial brief be adopted. Staff's recommendations continue to strike the right balance between DTE Electric's interests and its ratepayers' interests. Staff appreciates the time the Commission has taken to carefully consider each issue in this complex and voluminous read-the-record case.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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DATED: October 23, 2024

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 Reply Brief
Appendix A

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projection**	**Staff Adjustment**	**Staff Projection**
1	Rate Base	Appendix B	$ 22,067,519	$ (133,318)	$ 21,934,200
2	Adjusted Net Operating Income	Appendix C	$ 1,092,211	$ 83,916	$ 1,176,127
3	Overall Rate of Return	Line 2 ÷ Line 1	4.95%	0.41%	5.36%
4	Required Rate of Return	Appendix D	5.92%	-0.26%	5.66%
5	Income Requirements	Line 1 x Line 4	$ 1,306,905	$ (65,464)	$ 1,241,442
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	$ 214,694	$ (149,380)	$ 65,314
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	$ 289,758	$ (201,608)	$ 88,151
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	137,518	(572)	136,947
11	Revenue Deficiency / (Sufficiency)-Total	Sum Lines 8, 9, 10	$ 446,063	$ (210,832)	$ 235,230

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 Reply Brief
Appendix A1.1

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	**Return on Tree Trim Regulatory Asset**		
2	Average Balance Regulatory Asset	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	

Line No.	Description	2019-A	2020-A	2021-A	2022-A	2023	2024	2025	Reference
7	**Tree Trim Regulatory Asset**								
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)

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 Reply Brief
Appendix A1.2

	(a)	(b)	(c)
Line No.	**Description**	**Test Period Amount**	**Reference**
1	**Return on Monroe Regulatory Asset**		
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/	6.54%	Exhibit S-4, Schedule D1
4	Return on Monroe Regulatory Asset	136,947	

1/ Pretax WACC as proposed in this case was recalculated using 9% ROE in accordance with U-21193 order dated July 26, 2023

Michigan Public Service Commission
DTE Electric Company
Projected Rate Base
Periods Ending December 31, 2022 and December 31, 2025
($000)

Case No.: U-21534
MPSC Staff Reply Brief
Appendix B

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projection**	**Staff Adjustments**	**Staff Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	24,844,948	(141,204)	24,703,744
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	27,401,403	(141,204)	27,260,199
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(6,775,109)	12,450	(6,762,659)
8	Net Utility Plant	Line 6 + Line 7	20,626,294	(128,754)	20,497,539
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	20,794,695	(128,754)	20,665,940
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	20,787,646	(128,754)	20,658,891
15	Allowance for Working Capital	Exh.A-12, Sch. B4	1,279,873	(4,564)	1,275,309
16	Total Rate Base	Line 14 + Line 15	22,067,519	(133,318)	21,934,200

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21534
MPSC Staff Reply Brief
Appendix C

DTE Electric Energy Company
Development of Projected Net Operating Income
for the Test Year Ended December 31, 2025
($000)

		Revenue				Expenses									NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line No.	Description (Witness)	Sales Revenue	Base Fuel & Purchase Power Rev.	Other Revenue and R2 Rider	Total	Fuel and Purchased Power	Other O&M Expense	Depreciation & Amort.	Property Taxes	Other Taxes	State & Local Income Taxes	FIT	Other Utility (Income) / Deductions	Total	NOI	AFUDC	Loss on Reacquired Securities	Adjusted NOI
	Company Filed																	
	Operating Income (Direct)	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
	ACPP/TOD Amortization						(110)				7	22		(82)	82			82
	Uncollectible Expense						(3,800)				236	748		(2,816)	2,816			2,816
	Amortization of Deferred Incentive Comp.						(1,200)				75	236		(889)	889			889
	Depreciation							(1,426)			89	281		(1,056)	1,056			1,056
	Property Tax								(677)		42	133		(502)	502			502
	Interest Sync										56	177		233	(233)			(233)
	Rounding										-	-		-	-			-
											-	-		-	-			(1)
1	**Operating Income (Initial Brief)**	3,995,976	1,354,105	115,336	5,465,416	1,354,105	1,261,840	1,264,819	328,095	53,180	61,917	109,374	(6,400)	4,426,930	1,038,486	55,969	(2,244)	1,092,211
	Staff Adjustments																	
2																		
3	Revenue																	
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)				-		(6,041)				375	1,190		(4,476)	4,476			4,476
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 & 3 Cost Estimates (Rogers)				-		(1,828)				114	360		(1,354)	1,354			1,354
27					-						-	-		-	-			-
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	Impact of Cap Ex Adj on Prop. Tax & Depr. (Hecht)				-			(11,803)	(117)		740	2,348		(8,832)	8,832			8,832
37					-						-	-		-	-			-
38	Impact of Cap Ex Adj on Depreciation (Hecht)										-	-		-	-			-
39	Proforma Interest (Nichols)				-						511	1,621		2,132	(2,132)			(2,132)
40	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	1	2	-	2	(2)	-	-	(2)
41	**Total Adjustments**	3,235	-	-	3,235	-	(100,982)	(11,803)	(117)	-	7,724	24,497	-	(80,681)	83,916	-	-	83,916
42	**Staff NOI - Test Year**	3,999,211	1,354,105	115,336	5,468,651	1,354,105	1,160,858	1,253,016	327,978	53,180	69,641	133,871	(6,400)	4,346,248	1,122,403	55,969	(2,244)	1,176,127

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 Reply Brief
Appendix D

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure				Weighted Costs			
Line No.	Description	Amount ($000)	Percent Permanent Capital	Percent of Total Capital	Cost Rate %	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%

($000)

	(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**
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.	DTE Conceded at Initial Brief					
25	Strategic Capital Programs - Techology and Automation - NWA: Adaptive Networked Microgrids	(30,138)	No Impact as This Portion of CapEx is in CWIP				(24)
26	Strategic Capital Programs - Techology and Automation - NWA: Adaptive Networked Microgrids - Project Contributions	15,718	No Impact as This Portion of CapEx is in CWIP				14
27	**TOTAL: DISTRIBUTION**	**(14,420)**	-	-	-	-	**(10)**

($000)

	(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	**Demand Side Management:**						
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	**Information Technology:**						
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)**	**-**

($000)

	(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**
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	**TOTAL CAPITAL EXPENDITURE ADJUSTMENTS**	**(200,081)**	**(141,204)**	**(12,450)**	**(128,754)**	**(11,803)**	**(117)**
55	**WORKING CAPITAL ADJUSTMENTS**						
56	Non Utility Balance included in Other Accounts Receivable Total.				DTE Conceded at Initial Brief		
57	Charging Forward - Residential Customer Rebates & Business and eFleet Charger Rebates				(4,564)		
58	**TOTAL: WORKING CAPITAL**				**(4,564)**		
59	**TOTAL RATE BASE ADJUSTMENTS**				**(133,318)**		

Michigan Public Service Commission
DTE Electric Company
Summary of Staff Position
Projected Balances Period Ending December 31, 2025

	(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 Reply Brief				**(million $)**
	DTE Revenue Deficiency (Direct)				**$ 456.434**
	DTE Concessions				
	Rate Base Concession Rev Req Impact				(2.981)
	Depreciation				(1.426)
	Property Tax				(0.677)
	Change in ROR				(0.162)
	ACPP/TOD Amortization				(0.110)
	Uncollectible Expense				(3.800)
	Amortization of Deferred Incentive Comp.				(1.200)
	Rounding				(0.014)
1	**DTE Revenue Deficiency (Initial Brief)**				**$ 446.063**
2	**Staff Adjustments**				
3	Rate base	Appendix E * Exhibit A-14, Sch D-1	(133.318)	7.37%	$ (9.819)
4	Rate of return	Appendix B * (Appendix D less DTE Att 4)	21,934.200	-0.34%	(75.652)
5	Revenue	Appendix C, line 41			(3.235)
6	O&M Expense	Appendix C, line 41			(100.982)
7	Depreciation	Appendix C, line 41			(11.803)
8	Property Tax	Appendix C, line 41			(0.117)
9	AFUDC	Appendix C, line 41	-	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			**$ (210.833)**
13	**Staff Revenue Deficiency (Reply Brief)**	Appendix A, line 11			**$ 235.230**
	Walk from Staff Direct to Staff Reply Brief Revenue Deficiency				**(million $)**
14	**Direct - Staff Revenue Deficiency**	Exh S-1, Schedule A-1			**$ 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**
21	Rate base	See Below, line 45	(11.229)	7.02%	(0.788)
22	Depreciation	Appendix C			(0.390)
23	Property Tax	Appendix C			(0.102)
24	O&M	See Below, line 32			(0.668)
25	**Reply Brief - Staff Revenue Deficiency**				**235.230**
	Walk from Staff Direct O&M to Staff Reply Brief O&M				**($000)**
26	**Staff Direct**	Initial Filing, Schedule C1			**$ 1,161,522**
27	Merchant Fees	Initial Brief, Appendix C, line 16			5
28	**Staff Initial Brief**	Initial Brief, Appendix C, line 41			**$ 1,161,527**
29	ACPP/TOD Amortization	Adopt DTE Concession			(110)
30	Amortization of Deferred Incentive Comp.	Adopt DTE Concession			(1,200)
31	Projects with Level 2 & 3 Cost Estimates	Staff update calc at Reply Brief			642
32	Total O&M Updates				(668)
33	**Staff Reply Brief**	Initial Brief, Appendix C, line 41			**$ 1,160,858**
	Walk from Staff Direct Rate Base to Staff Reply Brief Rate Base				**($000)**
34	**Staff Direct**	Initial Filing, Schedule B1			**$ 21,967,013**
35	Distribution - Base Capital Programs	Iniital Brief, Appendix E, line 24			$ (25,202)
36	IT Projects - Return to Health	Initial Brief, Appendix E, line 32			2,335
37					-
38	Accumulated Deprecation				1,283
39	**Staff Initial Brief**	Initial Brief, Appendix B, line 16			**$ 21,945,429**
40	IT: MIGP Scope 3 Billing/Enrollment	Adopt DTE Concession			(1,950)
41	Accumulated Depreciation	Adopt DTE Concession			195
42	Operational Incentives Reg Asset	Adopt DTE Concession			(106)
43	Deferred Incentive Compensation	Adopt DTE Concession			(9,282)
44	DTE Accum Deprec Delta for DO 2023	Adopt DTE Concession			(86)
45	Total Rate Base Updates				(11,229)
46	**Staff Reply Brief**	Reply Brief, Appendix B, line 16			**$ 21,934,200**

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 23, 2024,** she served a true copy of **Michigan Public Service Commission Staff's Reply Brief** upon the following parties **via email only**:

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Administrative Law Judge
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De Ann M Payne
____
De Ann Payne

Subscribed and sworn to before me
this **23rd** 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