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October 5, 2022

Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: 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
MPSC Case No. U-20836

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Exceptions to the Proposal for Decision. Also attached is the Proof of Service.

Very truly yours,

Jon P. Christinidis

Digitally signed by Jon P. Christinidis
Date: 2022.10.05 16:46:05 -04'00'

Jon P. Christinidis

JPC/erb
Attachments

cc: Service List

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-20836

DTE ELECTRIC COMPANY'S EXCEPTIONS

TO THE PROPOSAL FOR DECISION

Dated: October 5, 2022

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I. INTRODUCTION

On September 19, 2022, the Administrative Law Judge (the ALJ) issued a Proposal for Decision (PFD). DTE Electric Company (DTE Electric, or the Company) agrees with the PFD's recommended disposition of some issues. However, the Company believes that other recommendations are based on incorrect or inapplicable analyses, or foundations that do not exist in the evidentiary record as required by the Michigan Administrative Procedures Act (APA), and, therefore, submits these exceptions.

DTE Electric attempts to be succinct in light of the Commission's knowledge and prior decisions. Further support for DTE Electric's positions and the reasons for those positions may be found in DTE Electric's Initial Brief and Reply Brief (including Attachments to those briefs), as well as DTE Electric's Application (including Attachments), testimony and exhibits, all of which are incorporated by reference in these exceptions. For consistency and ease of reference, the discussion is presented largely in the order that matters arise in the PFD, parties are generally referenced as designated in the PFD, and related matters are addressed collectively in the most relevant or logically-sequential context.

It is also important to note that changing one matter can result in corresponding changes to other matters (for example, depreciation and taxes) as numbers flow through calculations. Lack of a discussion by DTE Electric to separately address every issue suggested by or consequence resulting from the PFD should not be deemed to constitute an agreement by DTE Electric. DTE Electric, of course, maintains all of its appellate rights as well as all rights to address issues in other proceedings.

II. DTE ELECTRIC'S REQUESTED RATE INCREASE AND OTHER RELIEF ARE LAWFUL AND REASONABLE, SO THEY SHOULD BE APPROVED.

The PFD presents a "Legal Standards" discussion (PFD, pp 41-45) that is neither a finding of fact nor a conclusion of law, so DTE Electric need not take exception to preserve its rights. MAC R 792.10435. For convenience and brevity, however, DTE Electric collectively addresses certain matters to which it takes exception throughout the PFD.

First, the PFD (at p 42) notes that most of DTE Electric's discussion regarding legal standards is "not controversial," and that DTE Electric "properly cites… seminal cases" on ratemaking law. The PFD (at pp 42-45) further suggests, however, that in the context of this case, there is no "issue rising to the level of a constitutional concern." The Company disagrees, and maintains all of its constitutional rights that are presently involved or that might otherwise arise depending on how the Commission decides certain issues. Thus, the Company properly preserves constitutional issues, but recognizes that "an agency exercising quasi-judicial power does not undertake the determination of constitutional questions or possess the power to hold statutes unconstitutional."[1]

DTE Electric's rights include due process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right to fair and just treatment in MPSC proceedings: "No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed." Const 1963, art 1, § 17.

[1] *Wikman v Novi*, 413 Mich 617, 646-47; 322 NW2d 103 (1982). See also, *Taylor v Detroit Edison Co*, 475 Mich 109, 122; 715 NW2d 28 (2006) (MPSC lacked jurisdiction to decide constitutional issue, but had primary jurisdiction to decide case).

DTE Electric further notes for background context on the subject raised by the PFD that it has constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the U.S. Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, Mich Const 1963, art 10, § 2 provides in part, "Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law." These constitutional protections have been recognized and applied to public utility rates in well-established case law.[2] As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service.[3]

Michigan's Constitution further requires that all Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. Substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." [4] Expert testimony is "substantial" only if it is offered by a qualified expert who has an informed and rational basis for his or her view.[5]

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[2] See generally, *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri*, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); *Federal Power Comm v Natural Gas Pipeline*, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); *Duquesne Light Co v Barasch*, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). See also, *Northern Michigan Water Co v Public Service Comm*, 381 Mich 340; 161 NW2d 584 (1968); *Consumers Power Co v Public Service Comm*, 415 Mich 134; 327 NW2d 875 (1982); *ABATE v Public Service Comm*, 430 Mich 33; 420 NW2d 81 (1988).

[3] See *Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). See also *Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

[4] *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011).

[5] *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

When reviewing a PFD in response to exceptions filed by a party, the APA empowers the Commission to exercise all the power that it would have if it had presided at the hearing for cross-examination. MCL 24.281(3). Thus, the Commission retains the power to modify the PFD, so long as it does so based on the evidence in the record. Don LeDuc, *Michigan Administrative Law* § 6:69, at 478 (2d ed. Supp. 2010).

DTE Electric further notes and takes exception to the extent that the PFD suggests that the Company's requests for relief should be denied unless the Company overcomes some unstated (and unlawful) initial hurdle of evidentiary weight or other adverse presumption. [6] Evidence also cannot be disregarded simply because it stands in the way of the decision-maker's preference. Const 1963, art 6, § 28. The Commission also cannot draw inferences that are contrary to the undisputed record evidence. *White v Revere Copper & Brass, Inc,* 383 Mich 457, 462-63; 175 NW2d 774 (1970).

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained: "The party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation." Thus, unproven allegations cannot stand in the place of evidence. Things not proven must be taken as not existing, since a decision cannot be based upon conjecture.[7] The APA precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: "Evidence in a contested case… shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts

[6] DTE Electric is also not required to continually re-prove things where some party(ies) indicate a continuing disagreement. Although *res judicata* and collateral estoppel do not apply in a strict sense to MPSC rate decisions, issues fully decided in earlier MPSC proceedings need not be completely relitigated in later proceedings unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable. *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988).

[7] *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990).

within the agency's specialized expertise]." Noncompliance with the APA is reversible error.[8] It is similarly well established that an agency decision may not be based on speculation.[9]

Logistically, DTE Electric has the initial burden to prove its case by a preponderance of the evidence.[10] Other parties may challenge that evidence, but at that point the burden of proof shifts to the other parties. Thus, "once a utility has satisfied its initial burden of proof, another party 'may challenge that evidence and present evidence of unreasonableness.' However, at that point, the other party has the burden to demonstrate its position is correct." October 25, 2017 Order in Case No. U-18224, pp 14-15, quoting January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 38. This evidentiary standard also effectively bars last-minute criticisms of the Company's evidentiary presentation, as the Commission further explained:

> "The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented

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[8] *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

[9] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

[10] See generally, *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence"). The "preponderance of the evidence" standard is generally defined as follows:

> "***The greater weight of the evidence***, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that has the most convincing force; ***superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other***." *Black's Law Dictionary* 1301 (9th ed 2009). (Emphasis added).

in support of its position (January 11, 2010 Opinion and Order in case Nos. U-15768 and U-15751, pp 37-38).

Finally, for purposes of a collective general exception, DTE Electric notes that the PFD is unprecedented in length, and at times may reach conclusions that, in themselves, do not cause the Company to be aggrieved, but which follow extensive discussions (or that continue with further suggestions) that are inaccurate or otherwise objectionable (for example, as beyond the scope of this case, beyond the proper scope of a PFD under MCL 24.285, that speculate concerning various matters, that increase the relevant burden of proof, or that ambiguously suggest the need for more evidence). [11] DTE Electric declines to belabor the matter in the absence of a specific recommendation by the PFD, but notes generally that the PFD's discussion (here and elsewhere[12]) exceeds what is strictly necessary. The Company maintains that MCL 460.6a(1) (and other statutes) must be applied as written, [13] and controlling precedent must be followed.[14]

These matters are further discussed below in the context of specific issues.

III. DTE ELECTRIC HAS A $367.2 MILLION REVENUE DEFICIENCY.

DTE Electric's Initial Brief explained that the Company initially requested a jurisdictional rate increase of approximately $388.2 million; however, after reviewing Staff's and other

[11] MCL 24.285 relevantly states: "A decision or order shall not be made except upon consideration of the record as a whole or a portion of the record as may be cited by any party to the proceeding and as supported by and in accordance with the competent, material, and substantial evidence."

[12] See for example, PFD, pp 54-55, concerning the Company's discussion about the Court of Appeals rejecting ABATE's argument that the Commission is required to use the "used and useful" test in setting rates.

[13] *See, for example, Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[14] See, for example, MCL 7.215(C)(2) and (J)(1).

intervenors' positions, DTE Electric reduced its projected revenue deficiency to $367.9 million to account for five adjustments (listed as items a – e on page 1 of DTE Electric's Initial Brief, and further detailed in Attachments A and B). DTE Electric continues to support a revenue deficiency of approximately $367.2 million.

The PFD recommended a $145,680,000 revenue deficiency (PFD, pp 540, 729, Appendix A to PFD). It should be noted that the Company found numerous inconsistencies between the amounts identified in the PFD Appendices and the recommendations made in the narrative PFD. In some instances with respect to individual expenses, the PFD recommendation is simply not quantifiable. Thus, the $145.7 million revenue deficiency presented in the Appendices is not consistent with or supported by the narrative PFD. Nevertheless, the PFD's recommended revenue deficiency is insufficient and should be increased based on the controlling law outlined above, and the record evidence discussed below. Attachments A and B to DTE Electric's Exceptions support the Company's current position.

IV. DTE ELECTRIC'S RATE BASE IS $21.235 BILLION.

DTE Electric's initially-filed rate base was $21.268 billion, which the Company adjusted to $21.243 billion (DTE Electric Initial Brief, p 17). Staff recommended a rate base of $20,631,922,000, consisting of $19,229,736,000 of Net Plant and $1,249,327,000 of Working Capital (Staff Initial Brief, pp 1, 4-7; and Appendix B).[15] The Attorney General suggested a $679.9 million reduction in rate base, based on various recommendations reflected on Exhibit AG-1.26 (AG Initial Brief, p 79).

[15] The PFD, p 396, accurately reflects that there is no dispute about the working capital balance, so it should be adopted.

The ALJ agreed with the Staff and AG on a number of issues and recommended a total rate base of $20.47 billion (PFD, p 396; Appendix B to PFD). DTE Electric takes exception and maintains that its Rate Base for the projected period ending October 31, 2023, is $21.235 billion.

A. Energy Supply

Company witness Morren explained and supported total Energy Supply[16] capital expenditures of $636.5 million for 2020, $489.6 million for 2021, $398.6 million for the 10 months ending October 31, 2022, and $427.0 million for the projected test year (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (c), (d) and (f)). He provided an overview of expenditures for routine and non-routine projects as reflected on Exhibit A-12, Schedule B5.1, page 1 (Morren, 5T 647-50). He also described the major non-routine capital projects (5T 650-71; Exhibit A-12, Schedule B5.1, page 2), and the major routine capital projects (5T 671-707; Exhibit A-12, Schedule B5.1, pages 4-7).

The Company's Energy Supply planning process is a rigorous capital spending and approval process that is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations, while maintaining overall reliability performance and reducing costs (Morren, 5T 641-42). The majority of investments in the Company's fossil generating units are directed at the Tier 1 Monroe and Belle River power plants. These investments are reasonably and prudently required to support safe, reliable, and environmentally compliant ongoing operations. The minimal level of capital expenditures for Tier 2 coal-fired plants (River Rouge, St. Clair, and Trenton channel) were reasonably and prudently required to safely operate the units and comply

[16] In July 2021, the Company restructured some of its business units and combined Renewables Operations with the Fossil Generation business unit into a new integrated business unit called Energy Supply (Morren, 5T 630).

with legal and regulatory requirements until their 2021 and 2022 retirements (Morren, 5T 632, 647). (See generally, DTE Electric's Initial Brief, pp 19-41).

The Company discusses the PFD's proposed disallowances below, and generally disagrees with the PFD's characterizations that the Company was somehow required to provide additional or different evidence. Also as a preliminary matter, the Company notes that the PFD sometimes discusses items out of context and/or order (which might make the PFD's evidentiary criticisms seem more incisive than otherwise, but which renders the discussion out-of-context with the whole record to the extent that it neglects the overall evidence). For example, the PFD discusses (beginning at p 65) the Belle River Gas Conversion Study (engineering regarding the potential conversion of the plant's fuel source from coal to natural gas) before discussing (beginning at PFD, p 102) the net present value revenue requirement (NPVRR) analysis and other factors affecting the Company's decision to consider that fuel conversion.

1. Steam Electric Effluent Limit Guidelines (ELG) Rule Changes

Company witnesses Morren and Lee explained that the ELGs are national wastewater discharge standards that are developed by the Environmental Protection Agency (EPA), and that the EPA's regulations cover wastewater discharges from power plants operated by utilities. On October 13, 2020, the EPA finalized the ELG Reconsideration Rule, which revised some requirements from the 2015 ELG Rule to contain time-based options for complying with the updated rules for Bottom Ash Transport Water (BATW) and Flue Gas Desulfurization (FGD) wastewater. Bottom ash transport waters cannot be discharged to the environment after December 31, 2025 from a coal-fired power plant if the plant plans to continue coal-fired operations past 2028. Regarding FGD wastewater streams, plants with FGD systems can comply with one set of limits by December 31, 2025, or comply with a more stringent set of limits by December 31, 2028, if the

plant plans to continue coal-fired operations past 2028. The Reconsideration Rule did not alter fly ash transport water (FATW) discharge limitations, which continue with a December 31, 2023 compliance date (Morren, 5T 644; Lee, 7T 1589-1591).

On October 13, 2021, DTE Electric submitted Notices of Planned Participation (NOPP) to the Michigan Department of Environment, Great Lakes, and Energy (EGLE) for (1) cessation of coal burning at the Belle River Power Plant to achieve compliance with BATW discharge requirements, and (2) the Voluntary Incentive Plan (VIP) at the Monroe Power Plant for FGD wastewater compliance. (Morren, 5T 633-635; Lee, 7T 1591-1593). DTE Electric's NOPP for the Belle River Power Plant indicated a commitment to cease coal-fired operations by the end of 2028, with the option to evaluate a conversion to an alternative fuel source. This decision allows the Company to avoid installing $55 million of new ELG-compliant bottom ash technology by the end of 2025 (Morren, 5T 645, 711-712). (See DTE Electric's Initial Brief, pp 27-31, for a more detailed discussion).

2. Belle River Gas Conversion Study

Mr. Morren, who was previously the director of the Belle River Power Plant and therefore uniquely familiar with its operations, explained that the Company utilized the original equipment manufacturer (OEM) to perform boiler modeling, which determined that converting the plant from coal to natural gas is feasible from an engineering perspective focusing on the boiler. The Company then hired the OEM to complete a more in-depth broader project engineering study and detailed cost estimate for a natural gas conversion. The Company believes that a fuel conversion would be a minor and relatively low-cost alteration to the plant (*e.g.*, it would be a fraction of the cost of building a new power plant). The conversion would provide an expeditious means to address potential resource adequacy and other grid reliability considerations given widespread power plant

retirements across MISO Zone 7. A fuel conversion would retain Belle River's ability to supply 1,300 MWs of 24/7 dispatchable capacity and energy that currently benefits customers across Michigan (Morren, 5T 651, 769-771, 774, 782, 784, 787-788).

ABATE witness York proposed to disallow the Belle River Power Plant natural gas preliminary engineering study, reasoning that there is uncertainty whether the $2.5 million effort will be completed before the end of the test year (8T 3026). MNSC witness Comings similarly proposed a disallowance based on the Company not having made a final decision to convert the plant from coal to natural gas-fired operations (8T 4069). The PFD agreed with ABATE and MNSC, stating:

> After close review of the project documents, the PFD finds that MNSC's and ABATE's arguments are correct. DTE did not present an analysis of the economics of operating Belle River as a gas-fueled plant, to support the company's contention that the project is expeditious. As MNSC argues, the project scope for the engineering appears to encompass significantly more than an analysis of the cost of the project so a determination can be made whether to pursue conversion. [PFD, p 69.][17]

The Company disagrees and states that the PFD unreasonably demands more evidence where straightforward logic provides the correct answer. In addition to the discussion above, the Company submitted multiple documents showing that ABATE's postulated uncertainty is unfounded: (1) PAT Form 18325 (Exhibit AB-10, p 16) shows that that the effort is to be completed in 2022; (2) Exhibit A-40, Schedule EE5 states that the engineering work is to be completed in time to support the Company's 2022 IRP filing; (3) Exhibit A-40, Schedule EE6 indicates the work is to be completed in the third quarter of 2022, and (4) Exhibit A-40, Schedule EE7 indicates that the contract to complete the work has been executed (Morren, 5T 744).

[17] The PFD narrative is inconsistent with Appendix E.

The PFD's reliance on MNSC is similarly misplaced because the record reflects that MNSC's proposal was apparently based on a misunderstanding that the project is for engineering to convert the plant to natural gas. Instead, the project is to provide the information necessary to decide whether the plant should be converted to natural gas, as discussed above. Thus, MNSC's proposal was unfounded. The PFD's suggestion that DTE Electric should have provided some additional economic analysis regarding operating Belle River as a gas-fueled plant is unreasonable and illogical because it would "put the cart before the horse." This engineering study is appropriate and timely to determine the scope, schedule, and potential cost of a potential plant conversion. This information will form important inputs to the Company's upcoming IRP, and the Commission should not be deprived of that information as the PFD effectively suggests. Furthermore, it is beyond reasonable debate that converting the fuel source for an existing 1,300 MW power plant would involve a fraction of the cost of building a whole new 1300 MW power plant, so studying the feasibility of doing so is a logical, reasonable and prudent endeavor that will benefit the Company's customers. Therefore, the Company's requested cost recovery of $2.5 million should be approved (Morren, 5T 752).

3. Monroe Bottom Ash Conversion (ELG) and Monroe Fly Ash Basin Closure (CCR) projects.

The Monroe Power Plant provides essential support to the local and regional electrical grids because of its size, location, and operating characteristics.[18] Therefore, the Company is proceeding with Fly Ash Transport Water (FATW), BATW, and FGD wastewater projects to meet the fast-approaching ELG compliance deadlines (Morren, 5T 645-646). In summary, the Company is currently implementing projects for FATW ELG compliance according to the 2015 Rule, which

[18] The Monroe Power Plant has a capacity of over 3,000 MW, making it the largest power plant in Michigan, the second largest in the Midwest, and the fourth largest in the United States (Morren, 5T 645).

will importantly allow the plant to continue operating beyond 2023.[19] The Company will achieve BATW wastewater ELG compliance by the end of 2025.[20] The Company will achieve FGD wastewater compliance based on one of the options described above. If a BAT is selected, compliance must be achieved by December 31, 2025. If a technology that qualifies for the VIP is selected, compliance must be achieved by December 31, 2028 (Morren, 5T 647; Lee, 7T 1593).

ABATE witness York proposed a $23.614 million disallowance ($16.947 million in the bridge period, and $6.667 million in the test year) for the Monroe Bottom Ash Conversion (ELG) project, based on her opinion that it was unclear whether the Company would incur costs during the bridge period or projected test year (8T 3027). AG witness Coppola proposed disallowing $166 million of capital expenditures ($54,575,000 in the 10 months ending October 31, 2022, and $112,009,000 in the projected test year) for 13 routine and non-routine projects, reasoning that they lack the requisite internal approval to proceed with the proposed capital spending amount, so they should not be included in rate base (8T 4778-4779; Exhibit AG-1.14). The Company disagreed because the projects at issue (included in Exhibit A-12, Schedule B5.1, pages 2-7) have management approvals for the projects to be executed, and the funding levels being requested in the timeframe of this case generally match the current management approvals (Morren, 5T 729-734). [21]

[19] The FATW portion of the ELG Rule requires companies to cease water discharges related to the transport of fly ash by the end of 2023. The project to install piping, silos, and other infrastructure for the dry transport of fly ash from Monroe Power Plant boilers to a storage area was approved by the Company's Board of directors in 2020 and is fully underway (Morren, 5T 646, 651-652).

[20] The Company plans to terminate the use of water for transport of bottom ash at the Monroe Power Plant, and replace it by installing a dry drag chain conveyor system. The project is currently approved for engineering, design, and initial work, with additional approvals scheduled in 2022 (Morren, 5T 646, 652).

[21] The AG's attempt to pass judgment on future project funding that the Company is not requesting in this case should be disregarded. Mr. Coppola's $18.3 million recommended disallowance on line 7 of Exhibit AG-1.14 should also be

Mr. Coppola based his proposed disallowance on a single discovery response, STDE-3.7c, in which the Company indicated that several of the projects were scheduled to receive additional internal management approvals in the spring of 2022 (Coppola, 8T 4778-4779). But follow-up discovery response STDE-12.5 (Exhibit A-40, Schedule EE1) updated the approval status, reflecting that at that time of the initial discovery response (on April 13, 2022, which was over a month before Mr. Coppola's testimony was filed) several projects had now additionally received executed capital appropriation request forms (CARFs) for the funds being requested in this case. Mr. Morren also provided further details regarding the AG's incorrect lack-of-management-approval claim for three project categories: (1) routine capital ($30.6 million); (2) Monroe environmental ($18.5 million); and (3) Tier II decommissioning ($99.1 million). (5T 731-732).

Similarly, Company management has approved the Monroe Bottom Ash Conversion (ELG) project for engineering and material procurement ($18.9 million), and the Monroe FGD Wastewater (ELG) and Monroe Fly Ash Basin Closure (CCR) projects for engineering ($3.7 million and $1.8 million, respectively).[22] Additional funding approvals will be made as the projects progress to complete the scheduled work, which is required to timely maintain environmental compliance at the Monroe Power Plant. As discussed above, it is improper for the AG to request a disallowance solely based on a timeframe beyond this case (Morren, 5T 733-734; Exhibit A-40, Schedule EE1).

The AG responded by contending that she asked about this further in discovery, and the "response to AGDE-11.392 [Exhibit AG-1.69] contradicts witness Morren's rebuttal testimony" that the projects received corporate approval (AG Initial Brief, p 57). To the contrary, Exhibit AG-

completely disregarded because: (1) line 7 references Exhibit A-12, Schedule B5.1, page 2, line 29, but incorrectly displays expenditures from line 30; and (2) line 7 double counts a proposed disallowance for BlackStart projects (Morren, 5T 729-730).

[22] The first two projects are further discussed below. The PFD recommends approval of expenditures for the third project (PFD, p 92-93).

1.69 consists of a table summarizing the approved projects and attached approval documents, which confirm Mr. Morren's rebuttal testimony.

Regarding the Monroe Bottom Ash Conversion (ELG) project, the PFD states:

> Staff recommended holding projected bridge period expenditures to the updated projection, a reduction of $8,937,925. For the test year, Ms. Champion explained that Staff considered the degree of over projection in the company's filing for the bridge period, 53% as noted above, and recommended a 50% reduction to the test year projection.
>
> * * *
>
> While this PFD finds Staff's recommendation to be a reasonable alternative, this PFD concludes that DTE has not established that it will spend any additional money on this project in the 10-month bridge period of 2022 or in the test year, i.e. anything beyond its existing 2020 and 2021 expenditures. This PFD's review of the documentation offered in support of this project shows that the only approved spending was for 2020 and 2021 as shown on Exhibit AG-1.69, page 3. This approval document—with a signature dated December 21, 2020-is clearly not the "full authorization expected Fall 2022" that Mr. Morren acknowledged was pending in exhibit AG-1.23. instead, this is the approval form for the "engineering and material procurement" Mr. Morren referred to, but for 2020 and 2021 rather than 2022 and 2023.
>
> While Mr. Morren's rebuttal and his discovery responses in Exhibits A-40, Schedule EE1 and AG-1.69, page 2, claim that additional approval was granted for spending of $18.9 million—which he connects on page 2 of Exhibit AG-1.69 with DTE's 2022-October 2023 spending projection of $15.1 million—the approval provided was signed in December 2020 and covered spending only for 2020 and 2021… This PFD therefore finds that the 10-month bridge and test year projections for this project should be excluded from rate base. [PFD, pp 71-74.]

The Company disagrees with the PFD's disregard of the record in favor of recommending decisions based on the absence of some additional authorization form in a batch of documents provided in response to discovery on June 29, 2022 – the same day that the hearing began.[23] It is

[23] Furthermore, Company Witness Morren explained the Energy Supply capital planning process at some length, summarizing the effort as being *"designed to identify the optimal allocation of capital resources to meet safety and environmental regulations while maintaining overall reliability performance and minimizing costs."* (Morren 5T 642) The approval process varies according to its cost and complexity, is potentially iterative, and may not be perfectly linear – all of which explains why various internal forms may not neatly reconcile for ratemaking purposes but confirm that the overall process is reasonable and prudent.

beyond credible dispute that the Monroe Bottom Ash conversion project is important and ongoing. In addition to the discussion above, Mr. Morren highlighted the importance of timing to meet compliance requirements, the complexity associated with making major modifications to four of the largest coal-fired generating units in the country, and the major project work that began in 2020 (Morren, 5T 652, 745; Exhibit A-40, Schedule EE8; Exhibit AB-10, p 22). Moreover, each unit is effectively its own Bottom Ash Conversion (ELG) project. While the fourth and final unit does not need to be complete until the end of 2025, the other units need to have 100% of their work completed well ahead of time to meet regulation deadlines (Morren, 5T 745-746).[24]

Regarding the Monroe FGD Wastewater (ELG) project, the PFD states:

> This PFD finds that the 10-month bridge period and test year projected expenditures for this project should be rejected. While DTE does appear to have approved additional spending beyond 2021, the project document in Exhibit AG-1.69 shows that spending is "to perform engineering for the technology that is selected to meet compliance." Mr. Morren testified that the spending in this case was to test and evaluate alternative technologies that best meet the needs of the site-specific wastewater streams at Monroe. The scope of work he described is consistent with the first page of the approval documentation in Exhibit AG-1.69, page 5, which authorized spending of $1.7 million in 2020 and 2021, and indicated that project and that project along with an EPRI study, would enable the company to determine the best available technology to meet the effluent guidelines. While there is a project approval form with a signature dated November 15, 2021, this approval would have been granted well before DTE indicated in Exhibit AG-1.13 that "full authorization expected beyond 2022." In addition, the record does not establish that DTE has selected the technology to be employed, and thus has not established when the funds referenced in that form will be spent. Instead, it appears DTE is taking the time to evaluate its options, consistent with the Voluntary Incentive Program (VIP) Notice of Planned Participation (NOPP) that Mr. Morren referenced in his direct testimony. [PFD, p 76.]

[24] ABATE's Initial Brief, p 43, further asserted that "[b]ecause the project will not be used or useful within the period implicated by this case the Commission should reject recovery here." To the contrary, the Court of Appeals previously rejected ABATE's argument that the Commission is required to use the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). This is controlling precedent that must be followed. MCR 7.215(C)(2) and (J)(1).

The Company disagrees, incorporating the discussion above, which reflects that the record supports the Company's requested recovery. In addition, the PFD acknowledges that the projected spend in the case is approved (PFD, p 75). The PFD suggests disapproval based on the lack of exactly parallel language between testimony and exhibits, and approval being granted sooner than expected, neither of which is a sound basis to deny cost recovery. The PFD's further discussion (beginning with "In addition") also cannot support a decision because, as indicated in section II above (1) it neglects that the standard for recovery is preponderance of the evidence, and not the need to supply some additional evidence suggested (too late) by the PFD after the record is closed, and (2) speculates about what DTE "appears" to be doing based on the absence of such evidence. It is well established that an agency decision may not be based on speculation.[25] Thus, the Company should recover an additional $1.8 million.

Therefore, the PFD's proposed disallowances should be rejected.

4. Coal Combustion Residuals (CCR) Expenditures (Sibley Quarry Landfill Modification, and Monroe Bottom Ash Closure projects).

In DTE Electric's last general rate case, the Commission directed the Company, in this next rate case, to "provide a full accounting of current and future CCR costs--with such accounting clearly identifying funds collected to date, funds for the test year in that rate case, and funds projected for the future." (May 8, 2020 Order in Case No. U-20561, p 75).

Accordingly, Mr. Lee explained and supported Exhibit A-12, Schedule B5.1.1, which provides the historic and projected capital and O&M expenditures required to comply with CCR regulations at the Company's ten (10) CCR sites (the bottom ash basins at Belle River, Monroe,

[25] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

River Rouge, and St. Clair Power Plants, the St. Clair Scrubber Basin, the Belle River diversion basin, the Monroe Fly Ash Impoundment, and the landfills at Range Road, Sibley Quarry, and Monroe) (Lee, 7T 1596-1598). Forecasted capital expenditures are best estimates of site modifications required to meet currently known State and Federal regulations. O&M expenditures are based on current costs to operate CCR sites and engineering judgment of future site preservation and monitoring costs (Lee, 7T 1598). *See also* Uzenski, 7T 2770-2772; Exhibit A-30 Revised, Schedule U-1 regarding the recovery of CCR-related costs through rates.

ABATE witness York proposed a $24.073 million disallowance ($21.765 million in the bridge period, and $2.308 million in the test year) for the Sibley Quarry Landfill Modifications (CCR), asserting that it is uncertain whether the Company will complete the work for which the funds are requested (8T 3028). The PFD agreed with ABATE, criticizing the project's supporting documentation:

> This PFD finds that DTE has not supported the specific costs it will incur during the bridge and test year for this compilation of projects. DTE provided a disorganized set of project forms, with three project numbers for the landfill expansion, and multiple revisions… Nothing in the project documents or DTE's testimony reconciles the changes from the earlier version to the next, including the change in cost and the changes in construction start and completion dates. Nothing indicates whether work is under contract, whether any contract was competitively bid, or any other basis for the cost projections. While the company asserted the need to expand the landfill capacity, the supporting documents it cites do not provide support for specific expenditures or the timing of those expenditures, or provide a basis to conclude that the costs are reasonable and prudent. [PFD, pp 78-79.]

The Company disagrees because, again, the standard is preponderance of the evidence, not some need to somehow address additional issues after the record is closed. Furthermore, "project forms" utilized in the Company's complex internal processes that were requested and obtained through discovery and that (apparently) were not well understood, cannot logically form the basis of a disallowance. DTE Electric's testimony and exhibits fully explained and justified the

timeliness, reasonableness, and prudence of the relevant projects. Platitudes regarding perceived connections among Company internal processes and forms, project expenditures, and physical construction status prove only that a particular intervenor or witness misunderstands the Company's business processes; it does not demonstrate Company unreasonableness, imprudence, or some other basis for disallowance. ABATE's own Exhibit AB-10, pp 23-34, shows the yearly actual spends and future forecasts, approvals, and other pertinent data (an excerpt of that data is shown in the table at Morren, 5T 747). In addition to ABATE's proposal being unfounded, the project must be completed to support a timely and legally required closure of the Monroe Bottom Ash Basin. Therefore, any and all proposed disallowances[26] should be rejected (Morren, 5T 747).

ABATE witness York also proposed a disallowance of all funding ($57.3 million) for the Monroe Bottom Ash Basin Closure (CCR) project, asserting that it is uncertain if the Company is completing the work as scheduled and that a major portion of the work occurs after the test year (8T 3030). The PFD again agreed with ABATE, criticizing the project's supporting documentation:

> This PFD finds that DTE has not established that it is proposing reasonable and prudent expenditure that will actually be made as projected… It is not enough that the project is an important one, or that it need to be completed by 2025: DTE needs to establish that it is spending the money pursuant to a reasonable plan that can subsequently be reviewed with reference to something other than the total amount of spending. DTE has not provided RFPs, contracts, project milestones, or anything to show that the project is well managed and is going to be completed on some particular schedule. For these reasons, this PFD recommends that the Commission decline to approve funding for this project. Also, as noted above, DTE's ability to complete this project seems to depend on the completion of the Sibley expansion project discussed above, which DTE has not supported with evidence that it will be completed pursuant to any particular timeline, although it has a stated goal of completion by 2025. [PFD, p 91-92.]

[26] The PFD narrative is inconsistent with Appendix E.

The Company disagrees, incorporating its discussion above. Also, again, ABATE's proposal was not supported by ABATE's own Exhibit AB-10, pp 35-38, which shows that substantial work has been completed and is being done in a logical pattern for this type of major project (an excerpt of project spending is included in the table at Morren, 5T 748). ABATE's and the PFD's criticisms are also inconsistent with real-world construction, where productivity and planned activities on major earth moving projects often vary greatly on a month-to-month and seasonal basis. The project is also required by state and federal regulations. Continuing the work effort in an uninterrupted manner is necessary, logical, and well-supported, so the PFD's proposed disallowance of $57.3 million [27] should be rejected (Morren, 5T 654, 748-749). Furthermore, Exhibit S-10.4 (pages 1-2) shows that a considerable amount of expenditures associated with the work (exceeding $20 million) occurred from 2021-2022. The PFD's criticism that *"DTE has not provided RFPs, contracts, project milestones, or anything to show that the project is well managed and is going to be completed on some particular schedule"* cannot be squared with either the burden of proof or record in this proceeding. The burden of proof is a "preponderance of the evidence" --- not "beyond a reasonable doubt." There is authoritative testimony from Witness Morren[28] that the Monroe Bottom Ash Basin Closure project work is being executed, the funding is being utilized, substantial work has been completed and is well under way in a logical pattern for this type of project with substantial progress made. Furthermore, it is undisputed that the work must be completed for all four (4) Monroe generation units (recall that this is the 4th largest power plant

[27] The PFD narrative is inconsistent with Appendix E.

[28] Witness Morren has a BS in Mechanical Engineering and 35 years of experience with industrial projects, including nearly 20 years focused on DTE Electric power plant operation, engineering and maintenance. (5T 628-630)

in the nation) by the end of 2025, so while more detail might be interesting[29], there can be no reasonable doubt (and logic dictates) that the effort will be rapid and substantial. (5T 748-749) Therefore, Witness York's and the PFD's speculation does not withstand scrutiny.

5. River Rouge, St. Clair, and Trenton Channel Decommissioning

The AG proposed disallowances associated with the decommissioning of the River Rouge, St. Clair, and Trenton Channel Power Plants. The Company disagreed because its management approved $9.5 million, $9.5 million, and $9.7 million for the respective decommissioning projects. The removal of steam generating units involves three sequenced primary activities: decommissioning, decontamination, and demolition. The Company currently needs to and is completing make-safe decommissioning work to protect both personnel and the environment. Additional funding approvals will be made to complete the work as scheduled. The AG's proposal to defund the decommissioning projects should be rejected because the Company has already started this work and continuing the work uninterrupted is necessary and well-supported (Morren, 5T 655-656, 734-735; Exhibit A-40, Schedule EE1).

The same response essentially applies to ABATE witness York's proposed disallowance of decommissioning funds (8T 3031-3034). Witness York also attempted to justify her proposed disallowances utilizing small early capital project data, which she seemingly did not recognize as being related to an early phase of the work that predominately occurred while each plant was still operating. This data is irrelevant and therefore cannot support a decision (Morren, 5T 749).

The PFD states:

[29] On the other hand, it should also be self-evident that reasonable summaries of data and activity (like those provided by the Company) are a necessary aspect of a general rate case. MCL 460.6a(16)(a) relevantly provides "'Full and complete hearing' means a hearing that provides interested parties a *reasonable opportunity* to present and cross examine evidence and present arguments relevant to the specific element or elements of the request that are the subject of the hearing." A reasonable opportunity for a full and complete hearing does not require what the PFD suggests.

> Similar to the discussion above, this PFD finds that DTE has failed to support its projected timelines with respect to details other than a total spending projection…
>
> Because DTE has failed to provide any meaningful analysis or information regarding these projects, treating them collectively as simply a question of how much the spending would be in each period, this PFD finds that the recommended exclusions of the 10-month and test year expense projections should be adopted. [PFD, pp 97-100.]

The Company disagrees, incorporating its prior discussions of the evidence on this issue, and the preponderance-of-the-evidence and other standards for proper decision-making, as discussed in section II above. For example, and without limitation, the PFD speculates that "it is not clear" that approval by a senior vice president (as reflected at Exhibit AG-1.69, p 9) "constitutes the required level of approval" (PFD, pp 98-99). [30]

Furthermore, Exhibit AG-1.69 pages 9-21 contains substantial information (provided by the Company through discovery) in the form of Capital Approval Request Forms (CARFs) and Project Approval Team (PAT) review request forms concerning the decommissioning of the River Rouge, St. Clair, and Trenton Channel power plants. These forms include relevant expenses, participating and approving personnel, as well as narrative descriptions of the projects such as "Problem Description and Project Objective", "Brief Project Scope Summary", "Project Description and Approval", "Project Description and Approval Discussion", and "Major Risk and Risk Mitigants". This evidence, among other evidence set forth supra, refutes the conclusion in the PFD that "DTE has failed to support its projected timelines with respect to details other than a total spending projection [and]… DTE has failed to provide any meaningful analysis or information regarding

[30] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

these projects…" (PFD pp. 97-100) Therefore, additional revenue in the amount of $99.1 million should be approved.

6. Steam plant – routine capital expenses

The AG initially proposed disallowances for six routine capital projects premised upon the belief that those projects had not received sufficient internal approvals.[31] The Company explained that Exhibit AG-1.14, lines 13, 14, 20, and 23 total $26.3 million for the Belle River Unit 2 LP Turbine Rotor & Blades project, and the Renaissance Unit 1 Peaker Turbine Combustion Can project, which have proven management approval (Exhibit A-40, Schedule EE1). That discovery response further indicated that the Greenwood Unit 1 LP Turbine Rotor & Blades project ($3.5 million as shown on line 21 of Exhibit AG-1.14) was scheduled for an executed CARF in May 2022, which it received (Exhibit A-40, Schedule EE2). Therefore, $29.8 million of the AG's proposed $30.6 million disallowance should be disregarded as factually incorrect. The remaining $0.8 million concerns the Monroe Unit 3 Waterwall project which also should not be disallowed (Morren, 5T 732-733). The AG agreed in part. After recounting this, the PFD states:

> Looking at the Renaissance Unit 1 project, it appears the approval form that DTE relies on is page 29 of Exhibit AG-1.69. Mr. Morren reports this as spending approval for $19.8 million relative to the company's rate case bridge and test year projection of $24.1 million. A review of this page shows that $8.8 million of the capital expenditures reflected in the approval document are assigned to "prior years"; Mr. Morren did not address this. It appears the approved spending for the 10-month bridge and test year for this project that should be included in rates is limited to $11 million. For the Monroe project on page 7, line 181, DTE is projecting expenditures of $1 million in the projected test year; Mr. Morren's exhibit acknowledges that approval is not expected until August. In the absence of additional supporting information showing that this project will proceed as scheduled, this PFD recommends that it be excluded from rate base. [PFD, pp 101-102.]

[31] Staff did not recommend any adjustments to routine capital projects (Champion, 8T 5330).

DTE disagrees, incorporating the discussion above specifically for the Renaissance Unit 1 Peaker Turbine Combustion Can and Monroe Unit 3 Waterwall projects. Further discussion on the Belle River Unit 2 LP Turbine Rotor & Blades project is provided infra. However, it also bears emphasis that the PFD here incorrectly expands the burden of proof after the fact ("[i]n the absence of additional supporting information…"), engages in speculation to reach the ultimate conclusion ("[i]t appears") and engages in analyses beyond that which has been proffered by any party (see for example "[a] review of this page shows…"). This layering of additional hurdles for the first time in the PFD cannot form the basis for a disallowance. It is furthermore unclear what disallowance is even being recommended which provides yet one additional reason to reject the conclusions on this point in the PFD and simply approve the Company's reasonable and prudent proposal.

7. Belle River Power Plant NPVRR Analysis, and the Company's Decision to Cease its Coal-fired Operations.

The Company's net present value revenue requirement analysis (NPVRR) for its Belle River Power Plant, and resource adequacy concerns for MISO Zone 7, demonstrate the importance of continuing to operate the Belle River Power Plant. The most favorable outcome in the NPVRR analysis (Table 6 at Burgdorf, 4T 139) at a capacity price of CONE is ceasing Belle River's coal-fired operations in 2028. Based on the resource adequacy risks, NPVRR analysis, and the ability to avoid the $55 million bottom ash ELG-related costs discussed above, the Company decided that it would be in its customers' best interest for the Belle River Power Plant to cease coal-fired operations by the end of 2028 (Morren, 5T 712-713). (See generally, DTE Electric's Initial Brief, pp 31-38).

MNSC attempted to cast doubt on the Company's assessment of resource adequacy in Zone 7, and asserted that five projects (totaling $12.8 million) should be disallowed as avoidable because

the Belle River Power plant might retire in 2026 ($15.248 million with the engineering study discussed previously). The PFD agreed with MNSC, stating:

> As MNSC argues, DTE's conclusion regarding the economics or retiring Belle river depends on the selection of a narrow subset of alternative values of CONE [cost of new entry], which are historically high but not unprecedented recently. Clearly, the economics of retirement and an evaluation of potential alternatives to meet capacity needs will be further evaluated in the IRP. In this meantime, as DTE is continuing to evaluate its retirement options for Belle River, this PFD recommends that the Commission exclude the avoidable costs associated with the 2026 retirement date. The uncertainty surrounding the retirement date, with an upper bound on either retirement or fuel switching seemingly committed by 2028, also causes a concern that DTE will not actually invest in the avoidable costs, should funding be included in rates. While DTE argues that the expenses are "required" while it continues to evaluate its retirement options, it has not established a firm commitment to spend money as projected. [PFD, p 110.]

The Company disagrees because the PFD's recommendation is contrary to extensive record evidence and improvident in the current resource adequacy environment, as discussed below.

In DTE Electric's last general rate case, the Commission ordered the Company to "file a revised net present value revenue requirement analysis for its Belle River Power Plant using alternative retirement dates, as described in this order." (May 8, 2020 Order in Case No. U-20561, p 248). The Commission further explained:

> As noted in the Addendum to EGLE's Advisory Opinion in the IRP case, pending changes to environmental rules could present the opportunity to avoid significant capital expenditures at the plant over the next couple of years if the plant retires by 2028. *See*, filing #20471-0765, Case No. U-20471. This should be thoroughly examined, as it would impact the NPVRR analysis. Although the ALJ specifically referenced a 2025/2026 retirement date, the analysis need not be limited to that specific scenario and should consider other dates to determine the most cost-effective and reasonable approach. [May 8, 2020 Order in Case No. U-20561, p 82.]

The Company considered changes to environmental rules as discussed in the section above. The Company's NPVRR analysis further considered four alternative retirement dates (May 31, 2023; May 31, 2026; May 31, 2028; and May 31, 2030) each with four sensitivities with capacity

pricing of zero ($0); 10% of CONE ($9.48/kW-year); 50% of CONE ($47.40 kW-year); and CONE ($94.80/kW-year).[32] The results are summarized on Exhibit A-12, Schedules B6.1 – B6.3, and show a range of outcomes consistent with the range of capacity prices (Burgdorf, 4T 135-139; 5T 709).

Although the NPVRR provides a range of financial outcomes for the retirement of Belle River, it cannot be viewed alone. Mr. Morren explained that results from a NPVRR financial analysis is not the only factor that needs to be assessed when contemplating a plant retirement decision. Other factors, such as resource adequacy (whether the grid has sufficient resources to meet demand) and grid reliability, need to be understood when determining retirement dates in order to ensure customers retain a reliable and affordable power supply (Morren, 5T 712).

Mr. Burgdorf addressed resource adequacy by providing: (1) an overview of the MISO resource adequacy requirements and capacity market (4T 124-128); (2) an overview of the effective capacity import limit (ECIL) in MISO Zone 7 (where DTE Electric serves), which was 95 MW in Planning Year (PY) 2020/21, and 1,749 MW for PY 2021/22, and is projected to be approximately 773 MW for PY 2022/23 (4T 128-129), and (3) an overview of the MISO Zone 7 capacity position for Planning Years 2020/21 and 2021/22, and forecasted capacity position for Planning Years 2022/23 and 2025/26 (4T 129-135). Mr. Burgdorf expressed concern over capacity shortages particularly because Zone 7 was short of its Local Clearing Requirement (LCR, the minimum amount of unforced capacity that must be located in a Local Resource Zone to maintain reliability)

[32] Mr. Morren also explained that each retirement sensitivity was based on its own specific maintenance schedule, capital investment plan, and O&M plan. The maintenance plan incorporated a phase down in periodic outage durations as the units approached retirement. The capital and O&M expense forecasts also incorporated a phase down in scope and expenses consistent with the retirement date under consideration. Capital and O&M were set at levels required to ensure the safe, reliable, and environmentally-compliant operations for the time interval under consideration (Morren, 5T 709).

in Planning Year 2020/21, which resulted in the Zone 7 price clearing at the auction maximum of Cost of New Entry (CONE; $94,000/MW-year) (4T 129). He explained:

> The fact that Zone 7 fell short of its LCR in Planning Year 2020/21, the recent variability in MISO's CIL year-over-year, the changing resource mix in Zone 7, as well as siting and supply chain risks affecting deployment of new renewable resources presents a potential reliability concern that Zone 7 may not have enough resources to meet its LCR in Planning Years 2022/23 and 2025/26. Unexpected outages that lead to capacity dis-accreditation, timing to bring new generation online and changes in resource accreditation (particularly for renewable resources as their penetration within MISO increases) are additional risks that may contribute to Zone 7 falling short of capacity in the near future. Should Zone 7 fall short of capacity and thus [have] the LCR not met, the MISO clearing price for Zone 7 would be set at CONE (**as was the case in Planning Year 2020/21**) and the probability of a loss of load event (an event in which available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process. [Burgdorf, 4T 134-35. Emphasis in original.]

These resource adequacy circumstances demonstrate the importance of continuing to operate the Belle River Power Plant. The plant provides approximately 1,200 MWs of UCAP towards meeting the MISO Zone 7 LCR in PY 2025/26. The ability to reliably serve load in Zone 7 could be compromised if the Belle River units were retired, and therefore not available. As discussed above, if Zone 7 (where DTE Electric serves) does not meet the LCR, then the MISO clearing price for Zone 7 would be set at the CONE, and the probability of a loss of load event (available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process (Burgdorf, 4T 135; Morren, 5T 712). The Commission also recently recognized this concern in the July 2, 2021 Order in Case Nos. U-20886 and U-21099, p 10, which "emphasizes that the shortfall in LRZ 7 should serve as an important signal to LSEs of the severe economic consequences that could occur in the event of a loss of load event." Clearly, after the recent retirements of the Company's "Tier 2" power plants, now, an

important transition period, is not the time to be "penny-wise and pound foolish" with respect to maintenance at the Company's "Tier 1" power plants (i.e., Belle River and Monroe).

The most favorable outcome in the NPVRR analysis (Table 6 at Burgdorf, 4T 139) at a capacity price of CONE is retiring Belle River's coal-fired operations in 2028. Based on the resource adequacy risks, NPVRR analysis, and the ability to avoid the $55 million bottom ash ELG-related costs discussed above, the Company decided that it would be in its customers' best interest for the Belle River Power Plant to cease coal-fired operations by the end of 2028 (Morren, 5T 712-713).

MNSC witness Comings asserted that the Company's assessment of resource adequacy in Zone 7 (where DTE Electric serves) is unrealistic and misleading (8T 4049, 4059). The Company disagrees because Mr. Comings presented MISO capacity prices for the past 9 years to develop his conclusion regarding future capacity prices, despite acknowledging that "two of the recent auctions were near or at 100 percent of CONE in Zone 7" (8T 4060). His conclusion is not supported by recent MISO PRA prices and the transformation of the generation mix across MISO that is underway and expected to continue. MISO's presentation following the most recent PRA expressed concerns about continuing capacity shortfalls (Exhibit A33, Schedule X1, slide 9) and the recent OMS-MISO survey results shows a capacity deficit is projected in the MISO North-Central region for Planning Year 2023 with deficits expected to widen in subsequent years (Exhibit A-33, Schedule X3, slide 17). This recent information supports the Company's capacity price forecasts, including that CONE is a very likely outcome in the upcoming Planning Years (Burgdorf, 4T 141-144).

The Company's position is further supported by the Commission's recent Order in capacity demonstration Case Nos. U-21099 *et al*, in which the Commission discussed its concerns regarding the tightening of capacity resources, explaining in part:

> [The Staff report filed on March 25, 2022] also notes concerns regarding tightening capacity availability throughout the MISO zones and slimming margins for LRZ 7. *See*, Staff Report, pp. iii, 8, 17. ***The Commission shares these concerns regarding the tightening of capacity resources given the implications for resource adequacy and the economic and human impacts of capacity shortfalls. As described in last year's capacity demonstration docket,*** Case Nos. U-20866 *et al*., ***LRZ7 experienced a capacity shortfall that led to the PRA for that zone being set to CONE***. *Capacity Demonstration Results: Planning Year 2024/2025* in Case No. U-20886, filing #U-20886-0075, p. 4. While not included in this year's Staff report due to the MISO 2022/2023 PRA being conducted after the Staff Report was issued, the results were released on April 14, 2022. ***The MISO 2022/2023 PRA showed that all zones within the MISO footprint met their LCR, but LRZs 1-7 cleared at CONE, which for 2022/2023 is set at $236.66 per MW-day.*** [June 23, 2022 Order in Case Nos. U-21099 *et al*., pp 13-14; emphasis added.]

At bottom, an important part of providing reasonable and prudent electric service involves maintaining reliability. Acknowledging and balancing risk and potential consequences is part of the calculus.

Mr. Comings, on the other hand, simply asserts that the "Company could replace any capacity need with new resources" if Belle River is retired (8T 4060). The Company disagrees because any "new resources" would have to be above the current forecast. Plus there are risks of bringing on new renewable resources and the potential for MISO changes in renewable capacity accreditation with greater renewable penetration. Supply chain bottlenecks and other risks have grown since this case was filed, and would likely result in delays for any new project.[33] Moreover, Mr. Comings ignored the risk that other resources in MISO might retire causing a regional capacity shortfall, as was the case in PY 2022/23 for the MISO North-Central region (Burgdorf, 4T 144-145; Exhibit A-33, Schedules X1 and X3, slide 7).

MNSC's Initial Brief, p 18, further asserted that it is unrealistic to assume that the Company would retire Belle River without replacing its capacity because, for example, Belle River could be

[33] Exhibit A-033, Schedule X2 reflects some recent DTE Electric experiences with renewable project delays (Burgdorf, 4T 148).

converted to natural gas. The Company agrees that Belle River's conversion might be a viable alternative, but in that case Belle River would continue operating rather than retire.

Mr. Burgdorf also updated Table 5 from his direct testimony (at 4T 134) to reflect recent information as shown in Table 7 (at 4T 146), and explained that MISO capacity issues extend beyond Zone 7 so there is also a risk of insufficient external resources to import:

> Zone 7 has now cleared at CONE in two of the last three Planning Year Auctions and the results of the most recent PRA included other northern and central MISO zones also clearing at CONE. The fact that other MISO Zones cleared at CONE (not just Zone 7) shows an increased risk of relying on resources external to Zone 7 even if the Local Clearing Requirement (LCR) is met. I added a line item #10 to Table 7 forecasting the difference between Zone 7 resources (without Belle River) and the Planning Reserve Margin Requirement (PRMR). Zone 7 would be potentially short 1,210 MWs of capacity. While capacity can be imported, it will likely be unavailable as excess capacity is retired (as occurred in MISO North-Central region in the recent PRA). In the current 2022/23 Planning year, Zone 7 was short 397 MWs to the PRMR and there were not enough external resources to import. [Burgdorf, 4T 146-147.]

ITC witness Kopinski agreed with Mr. Burgdorf's direct testimony that "LRZ 7 is at risk of violating federal reliability standards given known thermal retirements and the potential for relatively small year-over-year changes in Capacity Import Limits," adding that the numbers in Mr. Burgdorf's original Table 5 "likely ***understate*** the reliability risk" (8T 4636 emphasis added). However, the PFD neglected to consider ITC's testimony.

Thus, Belle River's capacity remains important to Zone 7 reliability, and a hypothetical early retirement would risk a capacity shortfall (4T 147-148). Mr. Burgdorf concluded:

> The information shown in Table 7, with updated assumptions, shows that Belle River Power Plant is an important generation resource towards maintaining Zone 7 reliability standards. In addition, the most recent PRA provides further support against relying on external Zone 7 resources and is not a prudent option towards any potential replacement of Belle River capacity. In Planning Year 2025/26, Zone 7 would likely not meet its Local Clearing Requirement without Belle River, resulting in Zone 7 clearing at a price of CONE and not meeting federal reliability standards. [Burgdorf, 4T 148.]

This recent information provides additional support to the economic analysis to keep Belle River in operation through 2028. Thus, Mr. Comings' testimony provides no sound basis to support a decision regarding Belle River's retirement (Burgdorf, 4T 148-149).

Against all of this background, MNSC witness Comings also asserted that five projects (totaling $12.8 million) should be disallowed (as the PFD recommends) as allegedly avoidable because the Belle River Power plant might hypothetically retire in 2026 (Comings 8T 4050, 4066-4068). The Company disagrees because it has committed to ceasing coal-fired operations at the plant by the end of 2028, but it has not decided to retire the plant in 2026. As discussed above, the plant's economic operation is justified in the near term, and the plant has value for resource adequacy. The Company's upcoming integrated resource plan (IRP) will evaluate the long-term plan for the plant, including its conversion to operate on natural gas. The capital expenditures in this rate case are required to continue the plant's safe and reliable operation while it continues to provide energy for customers. Therefore, MNSC's proposed disallowance should be rejected (Morren, 5T 750-751).

Thus, the PFD's proposed disallowance is contrary to the record. It also bears emphasis that the capital expenditures are required to continue the plant's safe and reliable operation while it continues to provide energy to customers. They are not simply "required" in the context of a retirement decision as the PFD suggests (PFD, p 110, quoted more fully above). The Commission similarly is not permitted to draw inferences that are contrary to the record evidence.[34]

Therefore, the PFD's proposed disallowance of $12.8 million should be rejected.

[34] *White v Revere Copper & Brass, Inc,* 383 Mich 457, 462-63; 175 NW2d 774 (1970).

8. BlackStart Infrastructure, Site Security, NERC

AG witness Coppola proposed a full ($47.6 million) disallowance of the Company's BlackStart infrastructure improvements[35] based on his opinion that the Company did not provide sufficient information regarding the need, benefits, and cost recovery of the projects (8T 7494). The Company disagrees because it provided the cost and timing of the projects (Exhibit A-12, Schedule B5.1, page 2) and Mr. Morren's direct testimony discussed reasons that the projects are critical (Morren, 5T 658-59).

The PFD agreed with the AG, stating:

> The PFD finds that DTE does not have corporate approval to proceed with the 2022 expenditures for this project. The lack of approval, the company's inability to share details of the project, the lack of information regarding the total project cost or project completion date, and the information in Staff Exhibit S-10.4, page 1, showing actual 2021 expenditures of $384,00, well below the company's 2021 rate case projection, and actual expenditures for the three months of 2022 of only $105,000, cast doubt on the reliability of the company's forecast expenditures. This PFD finds that the projected bridge and test year costs for this project should be excluded from rates. [PFD, p 115.]

The Company disagrees, incorporating the discussion above. The PFD's "lack of approval" reasoning is also contrary to the PFD's own recognition (at p 114) that Exhibit S-10.5; Exhibit A-40, Schedule EE1; and Exhibit AG-1.69, p 2, reflect approvals. The PFD then further opines that DTE Electric "appears" to be relying on Exhibit AG-1.69, and further speculates that it might not reflect enough approval because it is only signed by Timothy J. Lepczyk (PFD, pp 114-15), despite the record reflecting that he is the Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and its subsidiaries, including DTE Electric (Lepczyk, 7T 1279). The project is also going forward, which plainly would not happen if it were not approved.

[35] BlackStart infrastructure includes assets utilized to restart the electrical grid after a blackout. Recovery from a blackout can only be accomplished if certain specifically-located generating units have the ability to self-start without the support of an external electrical power source. BlackStart units are specifically designated to offer that ability any time it is required (Morren, 5T 739).

The PFD's further criticism about "the company's inability to share details of the project" also falls wide of the mark in light of the record evidence and controlling law. Mr. Morren further explained that the BlackStart project funding relates to compliance with North American Reliability Corporation (NERC) reliability standards. The Company cannot disclose specific locations and specific work efforts associated with BlackStart facilities because they are considered critical infrastructure systems by MISO. The Company also does not decide which assets are appropriate for BlackStart infrastructure improvements. Instead, the System Restoration Plan (SRP) dictates how the Bulk Electric System would be restored during a blackout. The SRP is the responsibility of the transmission owner, and must comply with NERC reliability standards (Morren, 5T 739-741).[36] It would be unlawful and unreasonable to deny cost recovery based on the Company's compliance with security requirements.

Therefore, the Commission should reject any and all proposed disallowances [37], and instead find that the Company appropriately balanced the disclosure of information addressing the cost and purpose for the BlackStart projects while properly protecting the critical energy infrastructure information associated with its BlackStart projects (Morren, 5T 740-741).

9. Hydrogen Fuel System Pilot and Slocum BESS Pilot

Mr. Morren explained and supported two pilot projects that will introduce emerging technologies—hydrogen-fueled generation and a grid-scale Battery Energy Storage System

[36] Mr. Coppola's criticism about a lack of information regarding "when the Company will begin to recover through updated FERC Schedule 33 rates" (8T 4794) similarly falls wide of the mark in the BlackStart context. Per FERC Docket No. ER19-2241-000358429 from June 6, 2019, generation owners such as DTE Electric cannot request FERC rate recovery for BlackStart assets until the project is completed and the generation owner has demonstrated its ability to comply with applicable reliability standards (Morren, 5T 740).

[37] The PFD narrative is inconsistent with Appendix E.

(BESS)—into the Company's generation portfolio, and support the Company's advancement in the decarbonization arena (Morren, 5T 632).

The Hydrogen Fuel System Pilot (Exhibit A-12, Schedule B5.1, page 2, line 30) is a project to produce and utilize green hydrogen as a fuel source at the Blue Water Energy Center (BWEC) to aid in future carbon reduction. The project includes the construction of an 11 MW electrolyzer plant with storage capacity, and a fuel blending station that can support up to 5% of the BWEC's fuel requirement. Exhibit A-12, Schedule B5.1.2 details the need, goals, design, expected pilot costs, stakeholder engagement process, and public interest benefits consistent with the Commission-approved pilot process (Morren, 5T 659). Mr. Morren also provided additional testimony on these topics supporting the pilot (5T 659-667).

Staff, the AG, ABATE, MNSC, and GLREA opposed the hydrogen pilot. The PFD agreed, recommending a $18.2 million disallowance (Appendix E), stating:

> Because the testimony of Mr. DeCooman, Mr. Coppola, Ms. York, Mr. Comings, and Mr. Richter is persuasive that DTE has not justified the cost of the pilot relative to its potential benefits, this PFD recommends that funding for the pilot be rejected/limited to the amount recommended by Staff. [PFD, p 125.]

The Company maintains that it is unreasonable to give little weight to numerous factors favoring the pilot (Morren, 5T 743).

Although perhaps moot, the Company also takes exception to the PFD's further comments misconstruing a disproven and abandoned matter (PFD, pp 126-27). ABATE witness York proposed a full disallowance due in part to the engineering efforts for PMP 17315 having later completion dates than are found in PMP 17600 (8T 2024-2025). Witness York confused two different things. Mr. Morren explained that PMP 17315 (a $466,000 ancillary engineering project designed to provide insight into the future ability of BWEC to operate with up to a 100% hydrogen fuel blend) is not in any way associated with PMP 17600, which concerns the construction of the

pilot project to produce and consume hydrogen. Therefore, witness York's proposal was unfounded (Morren, 5T 741-742). ABATE did not dispute the Company's explanation that ABATE's witness confused two different engineering projects.

The Slocum Battery Pilot (Exhibit A-12, Schedule B5.1, page 2, line 31) is a pilot to replace the diesel-fueled peakers at the Company's Slocum peaker site located in the City of Trenton with a 14MW / 56 MWhr lithium-ion (Li-ion) BESS that will store excess energy that is generated on the grid during off-peak hours. This energy will then be available for dispatch during higher-priced peak hours. Exhibit A-12, Schedule B5.1.3 details the need, goals, design, expected pilot costs, stakeholder engagement process, and how the project is in the best interest of the public consistent with the Commission-approved pilot process. (Morren, 5T 667-668). Mr. Morren also provided additional testimony on these topics and supporting the pilot (5T 668-671).

AG witness Coppola proposed that the Commission reject the Slocum BESS Pilot (disallow $33.7 million) based on his opinion that the Company did not make a convincing case that it can create sufficient value for customers relative to the investment required (8T 4790). Mr. Morren responded by explaining that a BESS is a storage system for energy and not a generation unit (which Mr. Coppola attempted to use as a comparison) so it is able to release energy into the grid without any new emissions. There are also several additional factors that make a BESS a reasonable and useful addition to DTE Electric's energy supply options, including the expanding need for the electric grid to have additional energy storage levels due to the growth of intermittent generation, and Company management's full support and approval of more funding ($38.0 million, which includes $4.9 million risk-based capital) than the Company requests in this case, although the Company will endeavor to execute the project at the original projected cost (Morren, 5T 736-737; Exhibit A-40, Schedules EE3 and EE4). Moreover, "Staff is supportive of this pilot, as the Company

has shown it will provide a value to ratepayers" (DeCooman, 8T 5319), and MEIBC/IEI witness Sherman acknowledged the valuable learnings and experience that the Company can gain from this pilot (8T 4399).

Staff's Initial Brief, pp 19-21, proposed a $1,767,000 disallowance in the bridge period, and a $26,430,490 disallowance in the projected test year. Staff initially proposed a full disallowance of requested capital expenditures for the projected test year ($26,430,490), reasoning that the pilot did not have internal budgetary approval (DeCooman, 8T 5317-5318). As indicated above, however, the pilot received management approval for $38 million (Exhibit A-40, Schedule EE3 and EE4), so Staff's concern was addressed (see also 5T Morren, 761-762). Staff's Initial Brief, pp 20-21, responded:

> While Staff is generally supportive of this project, the information provided in rebuttal has not assuaged its concerns with the test year capital expenditures requested in this case. Specifically, while Exhibit A-40, Schedule EE4 includes the full internal budgetary approval, it also includes an updated scoping document with updated costs that align with the amounts identified for budgetary approval… . Given the fluidity of these costs, Staff's position to align the bridge period costs with the Company's forecasted amounts included as Exhibit S-10.4 and disallow capital expenditures in the test year until a future case when the costs have more certainty and can be fully reviewed is the most reasonable position and should be adopted.

The PFD stated:

> This PFD finds that the project funding for the bridge and test year should be excluded from rate base as the Attorney General recommends. Staff's confidence in the reasonableness of the project is persuasive to address the Attorney General's concerns with the benefits of the pilot. However, as Staff argues, DTE has not established a consistent spending plan for this project. Although Staff views the approval documents in Exhibit A-40, Schedule EE4, as containing new projections, this PFD concludes instead that the projections reflected in Schedule EE4 were the company's projections as of November 2021, and remain the company's projections as of the approval date of the project. It is Mr. Morren's description of the project and proposed spending, both in his testimony and in Schedule B5.1.3, that are not supported by the approval documents in key respects, including the project timeline and spending amounts. [PFD, p 131.]

The Company disagrees, incorporating its discussion above. It bears emphasis that Staff generally supported the project and acknowledged that it has full internal budgetary approval. The project involves substantial costs, as most recently and accurately reflected by the approved numbers. The PFD's indicated concerns are speculative, overstated, raise new concerns after the record is closed, and otherwise do not provide a sound basis for the PFD's proposed 100% disallowance. It bears emphasis that the PFD's new post-hearing concerns regarding Exhibit A-40 Schedule EE4, a Company discovery response offered only to respond to the Attorney General's asserted concern that the BESS project had not received sufficient internal approval (which it had; see 5T 737), misunderstands both the limited purpose for which the evidence was offered as well as the Company's internal processes involving CARF and PAT forms. While there may be some conceptual appeal to the expectation that internal forms will reconcile, attempting to do so (especially for the first time in the PFD) for ratemaking purposes disregards those forms internal functions and commercial reality. Particularly troubling is the recommendation to accept a disallowance amount premised upon a lack of internal approval advocated by Witness Coppola, when the BESS was clearly approved by the Chief Executive Officer. (PFD pp. 131-133)

Therefore, the Commission should reject any and all proposed disallowances[38].

B. Nuclear - Fermi 2

Mr. Davis described the operation of the Fermi 2 Nuclear Power Plant (Fermi 2) and supported Fermi 2's 2020 actual, as well as projected, capital expenditures through October 31, 2023. The Company's 2020 nuclear capital expenditures totaled $271.6 million, as listed on Exhibit A-12, Schedule B5.3, page 1, line 11, column (b). The projected capital expenditures are $450.4 million for the bridge period ending October 31, 2022, and $120.3 million for the projected test

[38] The PFD narrative is inconsistent with Appendix E.

year (Davis, 7T 2537-2538; Exhibit A-12, Schedule B5.3, page 1, line 11, columns (e) and (f)). (See generally, DTE Electric's Initial Brief, pp 42-45).

AG witness Coppola proposed to remove approximately $38.4 million of capital expenditures ($391,000 for 2020, $4,234,000 for 2021, $14,608,000 for the 10 months ending October 31, 2022, and $19,236,000 for the projected test year) associated with three projects: (1) Plant Radio System, (2) Security System Computer, and (3) Plant Wireless (8T 4797-4800; Exhibit A-12, Schedule B5.3, page 2, line 28; page 3, line 41; and page 3, line 50). The Company disagreed because Witness Coppola's proposal would unjustifiably reduce the recovery of capital expenditures that DTE Electric has already reasonably and prudently incurred, and that the Company reasonably and prudently projects to incur to replace and install systems that are critical to safely operating Fermi 2 (Davis, 7T 2577, 2584).

Mr. Davis explained that Witness Coppola's proposal was based on the apparent misconception that the Plant Radio System and Security System Computer are just ordinary business equipment, when instead they are critical to DTE Electric remaining compliant with its Nuclear Regulatory Commission (NRC) operating license and safe operations of Fermi 2. The Plant Radio System provides the necessary communications network for the safe operation of Fermi 2 and must remain operable during all postulated scenarios of plant operations because the system is credited in the Fermi 2 Emergency Response Plan. The Security System Computer provides necessary surveillance and perimeter intrusion detection capabilities for safe operation of Fermi 2, and must remain operable during a wide variety of challenging conditions to meet the plant's obligations under NRC regulations. Furthermore, replacing the existing plant equipment with a wireless system requires design changes to the plant and strict plant configuration controls and cyber security protocols. (Davis, 7T 2547, 2578-2579, 2580, 2583).

Mr. Davis also disagreed with witness Coppola's suggestion that the capital expenditures were not adequately supported, recounting his direct testimony, which was further augmented with project details in Attachment 9 of the Part III submission, and responses to the AG's discovery requests (Davis, 7T 2538, 2541, 2553, 2580-2852).

Regarding the Plant Radio System, the PFD states:

> This PFD concludes that DTE failed to establish that the level of its projected expenditure for this line item is reasonable or that the expenditures will actually be made as projected. The company did not establish that Mr. Davis's direct testimony or the referenced Attachment 9 contained any additional information overlooked by Mr. Coppola. The Attorney General included a portion of this information in Exhibit AG-1.66. The importance of a communication system to the safe and efficient operation of the plant is not the issue. The issues are whether DTE established that it will spend the forecast amounts in the bridge and test year, and whether the total amount is reasonable. Mr. Davis's reliance on the company's "prioritized list of projects" only confirms that the expenditure is indefinite. [PFD, p 137.]

To the contrary, the expenditures are supported by the evidence. There is no need to prove that Mr. Coppola "overlooked" something. The PFD's further speculation about the future also neglects that the importance of the system supports the reasonableness and certainty of the expenditure. The PFD also incorrectly characterizes Mr. Davis's testimony (quoted in part at PFD, p 135) as suggesting that there is no discipline or structure to the Company's nuclear expenditures. To the contrary, Mr. Davis explained the principles applied in determining how to properly maintain Fermi 2, including that the Company applies "a high degree of rigor", and "conservatism" with a recognition that safety is a particular priority in operating a nuclear power plant. (7T 2538-2539) As indicated above, the Plant Radio System provides the necessary communications network for the safe operation of Fermi 2, and must remain operable during all postulated scenarios of plant operations because the system is credited in the Fermi 2 Emergency Response Plan and 10 CFR 50.47 and 10 CFR 350. (7T 2579) He also explains that performing work at a nuclear power plant is unique and requires performance of work to the highest levels of nuclear standards – which are

not just "precautions" as asserted by Witness Coppola. (7T 2582-2583) Therefore, the PFD's proposed disallowance should be rejected. [39]

The Company also notes that it objected to the AG's briefing approach, including without limitation the general methodology of starting discussions by incorporating her witness's testimony "in its entirety," and without any specific transcript cites (*e.g.*, Initial Brief, p 64). The PFD states: "DTE's objection to the Attorney General citing without further reiterating pages of Mr. Coppola's testimony is actually helpful and not objectionable" (PFD, p 137). DTE Electric's objection is based on R 792.10434(3) which explains: "Briefs containing factual allegations claimed to be established by the evidence shall include a reference to the specific portions of the record where the evidence may be found.[40] Furthermore, in light of the substantial volume of material and tight timeframes in this proceeding, reasonable citation to the record is also the most practical approach to orderly briefing.

Regarding the Plant Wireless project, the PFD states:

> After reviewing the arguments of the parties and the record, this PFD concludes that DTE failed to support the projected expenditures. DTE's frustration with the number of discovery questions it must respond to does not justify a slapdash or hasty response. The Attorney General is not required to seek out additional information in support of the company's expense projections. Nonetheless, the Attorney General asked for an explanation "what is being done with the plant wireless that will require $6.1 million from 2022 to the end of the project test year." The response in pages 5-

[39] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[40] Courts have also repeatedly recognized, for example: "It is not sufficient for a party 'simply to announce a position or assert a claim of error and then leave it up to this Court to discover and rationalize the basis for his claims, or unravel and elaborate for him his arguments, and then search for authority to sustain or reject his position.'" *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998), quoting *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959). *See also*, *Gross v General Motors Corp*, 448 Mich 147, 161-62, n 8; 528 NW2d 707 (1995) ("Failure to properly brief an issue on appeal constitutes abandonment of the question"); *Isagholian v Transmerica*, 208 Mich App 9, 14; 527 NW2d 13 (1994).

> 6 of Exhibit AG-1.20 stated that the project costs are reasonable and prudent, and the "projected costs, scope and schedule for the plant wireless system were provided in the Attachment 9 of part II,' and provided examples to show that performing work at nuclear power plant involves unique considerations. Since DTE failed to establish the Attachment 9 Mr. Davis referenced was other than as Mr. Coppola described it, DTE has failed to show what this project entails, the necessity to undertake the project at this time, how the projected costs were determined, or why they were reasonable. [PFD, p 139.]

To the contrary, the Company supported its requested cost recovery with evidence including but not limited to the discovery responses as discussed above, and even further illustrated by the PFD's discussion. As Mr. Davis explained:

> While we think of wireless networks as perhaps a facility enhancement in everyday experiences such as wifi at the local library, the plant wireless system at Fermi 2 replaces existing plant data networks used for equipment monitoring and radiation monitoring. As I show in Witness Coppola's Exhibit AG-1.20, pages 5-6, replacing the existing plant equipment with a wireless system requires design changes to the plant, strict plant configuration controls and cyber security protocols – no different than any other plant equipment…The Part III information adequately details projects such as the Plant Wireless, Plant Radio and Security System Computer projects. The Part III information includes detailed information such as amongst other information: when the project was initiated, when the project is expected to complete, the basis for performing the work, the scope of the work, the project's funding status, who is performing the work, how many workers are expected to be used on the project, and the standards to which the work must be performed and project amounts depicted in the previous DTE Electric electric rate case per U-18238…DTE Electric's Attachment of Part III includes detailed monthly expenditures by cost element for the Plant Wireless project and accordingly, the Plant Wireless project was not projected to begin until following Refueling Outage 21, so as expected, there would be no reasonable expectation to have competitive bid information to share until the project has been awarded. [7T 2580-2582.]

The Company also takes exception to the PFD's characterization of discovery. The Company responded to over 5,600 audit and discovery requests.[41] Despite that massive volume,

[41] Discovery, particularly in rate cases, is much more rapid than the timing expectations set forth in the Michigan Court Rules, and it was apparent in this case that some parties did not read relevant responses to discovery requests. (See Exhibit A-41 Schedule FF10; 4T 462-463)

and the direction to respond in roughly ¼ the standard time set forth in the Michigan Court Rules[42], there is no basis for the PFD's conclusions that discovery responses were insufficient, "slapdash" or "hasty" (to the extent "hasty" might be construed to convey that such material was poorly prepared). The scheduling order, which reflects an 8-business-day turnaround before the Staff/Intervenor filing date, and a 5-business-day turnaround after that, effectively required that all discovery responses are "hasty" (to the extent "hasty" might be intended only to mean fast). The Company should not be criticized for compliance. [43] Therefore, the PFD's proposed disallowance should be rejected.

Regarding the Security System Computer project, the PFD states: "This PFD again finds Mr. Coppola's testimony persuasive. There is no evidence DTE has obtained a competitive bid for this project" (PFD, p 141). The Company maintains that the record supports its requested cost recovery, incorporating the discussion above. See, for example, Exhibit AG 1.20:

> Question: Refer to page 10, lines 15-25 of Mr. Davis' direct testimony. Please: (a) Explain why $24.8 million for a security video system is not an excessive cost for such a system. Provide evidence otherwise.
>
> Answer: The projected costs for the security computer system are reasonable and prudent to achieve the objective of replacing the full security computer system, which includes computer servers, video cameras and other detection devices to alert plant security of security risks and to maintain positive surveillance of the Fermi 2 Power Plant.

[42] MCR 2.309(A)(2) provides *"Each separately represented party may serve no more than twenty interrogatories upon each party. A discrete subpart of an interrogatory counts as a separate interrogatory."* MCR 2.309(B)(4) provides *"The party on whom the interrogatories are served must serve the answers and objections, if any, on all other parties within 28 days after the interrogatories are served…"*

[43] See for example, *In re Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002) (reversing the MPSC because it misinterpreted and misapplied its own rule in order to reach its desired result); *DeBeaussaert v Shelby Twp*, 122 Mich App 128, 130; 333 NW2d 22 (1982) ("Once an agency has issued rules and regulations to govern its activity, it may not violate them"); *Bohannen v Sheridan-Cadillac Hotel, Inc*, 3 Mich App 81, 82; 141 NW2d 722 (1966) ("When an administrative agency promulgates a rule for the benefit of litigants and then deprives a litigant of this right, it is a violation of both the 1908 and 1963 Michigan Constitutions").

Projected costs, scope and schedule for the security computer system were provided in Part III, Attachment 9.3. These projected costs, scope and schedule are best effort projections and contain no amounts for contingency.

Performing work at a U.S. commercial nuclear power plant such as Fermi 2 Power Plant involves unique considerations. I include as examples:

- Replacements such as security computer replacement are subject to strict design configuration controls to ensure plant design remains consistent with the Fermi 2 design basis and operating license; this requires detailed engineering analysis, calculations and design documents to be development [sic developed] prior to work execution as well as post-implementation.

- Work within the Fermi 2 Protected Area requires personnel to obtain and maintain special access approvals 24 hours per day, 7 days per week, 365 days per year to Fermi 2 Power Plant; all materials entering the Fermi 2 Protected Area must be hand-searched prior to entering the Protected Area.

- The Fermi site covers approximately 1200 acres, is accessible by road, railway, and water, includes multiple buildings and, at times, hosts upwards of 2000 persons performing work.

- Excavation must be done using soft dig methods to ensure critical systems including systems providing nuclear safety functions remain capable of performing their function.

- In general, the existing systems must remain operable while the replacement work is occurring.

- Electronic equipment, computers and other plant interfacing systems must be compliant with cyber security regulations which impose strict manufacturing, shipping, receipting and warehousing requirements. [Exhibit AG 1.20]

The PFD appears to merely accept without challenge AG Witness Coppola's *one sentence* dismissive summary of these explanations of the complexity of the security computer system.[44] DTE Electric submits that a more balanced analysis inevitably leads to the more reasonable conclusions that the security computer system at a nuclear power plant like Fermi 2 is a very important high-tech system that requires strict design controls which increases cost, high security

[44] "With regard to the challenges of working within a nuclear facility, those challenges in and of themselves do not provide evidence to spend $24.7 million on this project." (PFD p. 140-141; 8T 4799)

which slows down construction, increases complexity and increases cost, hand excavation which slows down construction and increases cost, and covers hundreds of acres, multiple buildings, and virtually every possible means of access which increases cost.

The PFD also appears to have misconstrued Mr. Davis's rebuttal testimony that: *"Again, DTE Electric's Attachment 9 of Part III includes detailed monthly expenditures by cost element for the Security System Computer project. Furthermore, in response to the Attorney General's discovery requests, DTE Electric did demonstrate the use of competitive bids for the Security System Computer project"* (7T 2582). The Attorney General's own Confidential Exhibit AG 1.67 contained twenty six (26) pages of material associated with the Company's commercial efforts regarding the Plant Wireless Project, Plant Radio System, and Security System Computer Project. Pages 5, 10-11, and 24 specifically provide bidder score cards with criteria and scores. Page 24 is the bidder scorecard with respect to the Security System Computer project. Therefore, for the reasons discussed, the PFD's proposed disallowance is based on factually erroneous conclusions and should be rejected.

Finally, it should be noted that while the PFD narrative implies agreement with certain aspects of the AG's arguments regarding the three contested nuclear generation capital projects, DTE Electric notes the PFD stopped short of recommending a disallowance of the three contested nuclear generation capital projects. DTE Electric takes exception to the ALJ's reasoning on these projects and firmly supports its basis for full recovery.

C. Distribution Operations (DO)

DTE Electric supports Distribution Operations (DO) capital expenditures of $905 million in 2020, and which are projected to be $2.3 billion for the 22-month bridge period ending October 31, 2022, and $1.4 billion for the projected test year (Pfeuffer, 4T 230; Exhibit A-12, Schedule B5.4, page 1, line 23, columns (b), (e), and (f)).[45] (See generally, DTE Electric's Initial Brief, pp 45-50).

The Company has two broad categories of capital expenditures: (1) Base Capital, and (2) Strategic Capital.

Base Capital programs include work that the Company must perform to recover from interruptions in electric service (*e.g.*, emergent replacements due to storms, and equipment failures at substations), to address customer requests for new or upgraded service connections, or to relocate equipment in response to third-party requests (*e.g.*, MDOT). Details are included in Exhibit A-12, Schedule B5.4, pages 3 to 7, with more detail in Exhibit A-23, Schedule M3 (Pfeuffer, 4T 230-231). Ms. Pfeuffer also explained the forecasting methodology for base capital, which is based on a combination of prior year plus inflation for new business and third-party requests, and a three-year average for emergent capital expenditures (4T 370-377).

Strategic Capital programs include work that the Company is performing to improve safety, reliability and operability, and grid modernization. These investments are subcategorized into three areas or investment pillars:

[45] Pages 1 and 2 of Exhibit A-12, Schedule B5.4 provide a high-level overview of base and strategic capital investments. Pages 3 to 11 provide additional support including forecasting methodology and project lists. Exhibit A-23, Schedules M-3 through M-6 provide detailed descriptions of each project or program listed in Exhibit A-12, Schedule B5.4 (4T 378). Ms. Pfeuffer also provided detailed explanations of Exhibit A-12, Schedule B5.4 (Pfeuffer, 4T 378-386), and Exhibit A-23 (4T 386-387).

- *Infrastructure Resilience and Hardening.* These projects and programs focus on hardening the system, addressing frequent outage circuits, and replacing aging infrastructure. Exhibit A-12, Schedule B5.4, page 8 provides details, with additional details at Exhibit A-23, Schedule M4 (Pfeuffer, 4T 277, 289).
- *Infrastructure Redesign and Modernization.* This area focuses on major projects that generally involve the construction of substations and the rebuilding of large portions of circuits. Exhibit A-12, Schedule B5.4, pages 9-10 provide details, with additional details at Exhibit A-23, Schedule M5 (Pfeuffer, 4T 277, 313).
- *Technology & Automation.* These projects and programs are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications. They meet current grid need and provide immediate benefits to customers, lay the foundation for grid modernization, and will support increased adoption of DERs and EVs. Exhibit A-12, Schedule B5.4, page 11 provides details, with additional details at Exhibit A-23, Schedule M6 (Pfeuffer, 4T 277, 347-348).

1. Base Capital

ABATE witness York suggested that the Company should continue to use a five-year average to forecast emergent replacements rather than a three-year average (8T 3036). The Company disagrees because there has been an increasing trend of weather events, as well as outages from storms and peak wind speeds, so using a shorter-term average is a better predictor of future emergent replacement costs (Pfeuffer, 4T 248, 250, 489-90; Exhibit A-41, Schedule FF15).

Staff also criticized the Company's use of a three-year average, suggesting that customers could be at risk for paying for emergent replacements that do not materialize (Becker, 8T 5400). To

the contrary, over the past several years an *under-projection* in required emergent capital has contributed to the Company's need to shift resources from strategic capital. The Company believes that the three-year average provides a more accurate forecast for future emergent expenditures. Further, if the emergent expenditures do not materialize at the projected level, then the Company would be able to shift those resources to exceed its planned strategic capital investments to improve the reliability of its system more quickly. Thus, the three-year average is reasonable and prudent because it reflects recent trends, provides for appropriate planning, and there is no risk that the capital will not be spent (Pfeuffer, 4T 490-492).

The PFD states:

> This PFD finds that the 5-year average should continue to be used for this category, with the inflationary or normalization method previously approved by the Commission. Ms. Pfeuffer acknowledged that weather is highly variable from year-to-year, and DTE did not establish that the 3-year average would be more accurate. Instead, it presented five-year averages in only 3 data points, and additional information that is inconclusive. While Ms. Pfeuffer's contention that the three-year average "better represents the conditions the Company has experienced recently" is tautologically true because three years are more recent than five, it says nothing about the predictive power of a 3-year or 5-year average. Nor is it clear that a rate case projection "better allows the company to plan and prepare for" the required emergent work, since planning and preparing for that work is one of the Company's primary responsibilities. As Mr. Becker testified, the consistent use of the 5-year average method should adequately protect DTE's interests, while a significant overprojection by undue reliance on two years of extreme data will not adequately protect ratepayers. Thus, the PFD concludes that Staff's adjustment should be adopted. [PFD, pp 150-51. Footnotes omitted.]

The Company agrees that normalization should continue,[46] but disagrees with the PFD's recommended 5-year average because a 3-year average is a better predictor of future emergent replacement costs, as reflected by the record discussed above. If the Commission believes that more

[46] Prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2020 dollars) because the value of a dollar changes over time due to inflation (Pfeuffer, 4T 492-493). The Commission approved the Company's normalization practice its most recent rate case. (May 8, 2020 Order in Case No. U-20561, p 86).

severe weather will now predominate, then a three-year average will be a better predictor of future expenses and system requirements.

The Company also takes exception to the PFD's further comments (particularly at p 152), which do not properly characterize the Company's spending and the effects of weather. Overall, the Company invested $44.0 million more in 2020 than it forecast in Case No. U-20561 (approximately 5%).[47] The difference was primarily due to higher-than-projected Emergent Replacements (restoration of customer outages due to storm or equipment failure and hazard remediation), which were approximately $96.5 million more than the forecast. These expenditures were necessary to restore safe and reliable service to customers, and were reasonably and prudently incurred, so they should be approved. When weather events cause outages for customers, the Company must respond as quickly and safely as possible to restore electrical service. This often requires a shifting of priorities in investments, equipment, and labor, from previously planned activities to emergency restoration efforts. Replacing old, outdated equipment with higher-standard equipment (such as poles rated to a higher class or fiberglass crossarms instead of wooden crossarms) also increases restoration costs but results in a grid that is more robust to severe weather (Pfeuffer, 4T 242-243, 246, 249-252).

AG witness Coppola also proposed disallowances in select other base capital programs (Major Equipment; Normal Retirement Unit Change-Out (NRUC) & Improvement Blankets; and General plant, Tools & equipment and Miscellaneous) based on his belief that the Company should estimate these investments using a five-year average of past expenditures (8T 4751-4757).

Regarding Major Equipment, the PFD states:

> This PFD finds that it would not be reasonable to project this category using the highest reported value; updating the projection with the most recent (2021) value

[47] The Order from Case No. U-20561 included $850.6 million of distribution plant expenditures in rate base, which was $54.3 million less than the actual amount that was reasonably and prudently incurred in 2020 (Pfeuffer, 4T 244; Exhibit A-12, Schedule B5, line 7).

> adjusted for inflation is an option, but the 5-year average recommended by Mr. Coppola appears to be the most reasonable approach with the normalization adjustment Ms. Pfeuffer calculated. Using the projected 10-month bridge and test year calculations for the five-year average in Schedule FF16 of Exhibit A-41, this PFD calculates revised reductions of $5.01 million and $6.01 million for the bridge and test year, respectively [PFD, p 155. Footnote omitted.]

Regarding NRUC and improvement blankets, the PFD states:

> This PFD finds that the Attorney General is correct that DTE's projection method for this category is flawed, given the variability of expenditures in this category from year to year. Because the Attorney General's recommendation addresses the entire category, this PFD recommends that her adjustments be adopted, with the addition of the normalizing adjustments for the five-year average presented by Ms. Pfeuffer. The resulting reductions to the 10-month bridge period and test year projections are $6.23 million and $7.66 million, respectively. [PFD, p 159. Footnote omitted.]

Regarding General plant, tools and equipment, the PFD states:

> Consistent with the discussion above, this PFD finds that a project based on 2020 expenditures adjusted for inflation is not appropriate for this category given the variation from year to year. This PFD concludes that a five-year average is the most reasonable of the alternative projections, normalized for inflation as shown in Schedule FF16 of Exhibit A-41. The resulting adjustments to the bridge and test year expense projections are $1.72 million and $0.67 million, respectively.[48] [PFD, pp 160-61. Footnote omitted.]

The Company again agrees with normalization as indicated above, but otherwise disagrees because a five-year average of expenditures is not the most accurate representation of the future expenditures. The Company typically uses an average of historic spending to forecast expenditures that tend to show significant volatility, year over year. Expenditures in these base capital programs (Major Equipment; Normal Retirement Unit Change-Out (NRUC) & Improvement Blankets; and General plant, Tools & equipment and Miscellaneous) lack significant volatility, and are more consistent historically (Pfeuffer, 4T 499-500). The Commission accepted the Company's use of

[48] The Company also notes there is a discrepancy between the narrative portion of the PFD, which indicates a recommended disallowance of $2.39 million ($1.72 million plus $0.67 million), and Appendix E, which shows $3.032 million. This and other inconsistencies throughout the DO section of the PFD between the narrative and Appendix E creates a challenge when evaluating the ALJ's intent.

prior year actual expenditures plus inflation for these programs in Case No. U-20561, and the methodology remains reasonable and prudent (Pfeuffer, 4T 500).

If the Commission decides to change the methodology for this case, which it should not, then the Company recommends a three-year historical average (2019-2021) plus inflation as shown in Exhibit A-41, Schedule FF16 (which the PFD recognized as an option but declined to recommend). This three-year average is better than a five-year average because it incorporates recent significant increases to resources and funding to improve the electrical grid, and these years will more accurately represent future expenditures than earlier years prior to 2019 (Pfeuffer, 4T 499-502).

Staff also proposed disallowances ($1.667 million in the bridge period; $2 million in the projected test year) for NRUC & Improvement Blankets, suggesting that the Company did not support its $2 million annual increase for 2022 and 2023 in response to discovery (Becker, 8T 5406). To the contrary, the referenced discovery response stated that the additional $2.11 million was requested by regional planning engineers, who are often the first line of defense in supporting specific customer reliability and power quality concerns. The Company needs this funding in order to be more locally responsive to customer complaints for timely execution of small projects to improve customer reliability (Pfeuffer, 4T 502-503). The PFD states:

> This PFD also concludes that Staff's analysis is correct in that DTE failed to establish the reasonableness and prudence of the additional $2 million in annual spending for line 28. The company's citation to the request by engineers is not sufficient to justify the expense, nor does it match the company's initial claim that the increase was due to the higher cost of projects. [PFD, p 159.]

The Company disagrees because it properly supported its request for increased cost recovery and explained the reasons for the cost increase. As indicated above, the additional $2.11 million was requested by regional planning engineers to address very real needs of customers, including

reliability and power quality concerns. The Company will use this funding to be more quickly and locally responsive to customer concerns and complaints (Pfeuffer, 4T 502-503). Witness Pfeuffer explained that:

> [T]he additional $2.11 million was requested by regional planning engineers, who are often supporting specific customer reliability and power quality concerns, to support doing more small projects locally to improve customer reliability concerns in a quick and efficient manner. Increased funding to the regional planning engineers, typically the front facing employees closest to our customers, ensures that they have the flexibility to quickly resolve smaller in scope reliability equipment issues. [4T 502.]

Thus, there are higher project costs because there are more projects. The PFD's rationale (that DTE should somehow be locked into only being able to support higher costs per individual project, rather than higher project costs collectively) provides no sound basis for a decision, and disregards the evidence that the Company needs the additional funding to increase the number of small projects.[49] Staff also did not disagree with the necessity of investments in this category as a whole, and the PFD also does not make such a suggestion. Therefore, the Company's requested cost recovery should be approved.

2. Strategic Capital

The PFD begins its discussion with comments indicating that the Company has engaged in "chronic underspending" in this category (*e.g.*, PFD, pp 163, 166). The Company disagrees with that characterization. As indicated above, and also historically, underspends in strategic are coupled with overspends in emergent capital. While the Commission has indicated it would like the Company to meet strategic investment goals even when there is an overspend in emergent, this is not always possible. This is because it is not merely a question of dollars. The more pressing problem is the amount

[49] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28.

of finite human and physical resources. Take a simple example for instance: say the Company has prepared for 100 crews to dedicate their time to strategic work, but half of those crews are then required to respond to emergency outages instead, even after the Company brings in additional crews from outside the service territory. In this scenario there will only be 50 crews available to do the planned strategic work. Even with the dollars ready for investment, the Company's ability to actually spend the dollars is hampered by the reduction in the amount of available work crews. The Company is still paying for 100 crews (plus additional crews from outside the service territory), however, the dollars for half of the investment pull from the emergent bucket rather than the strategic bucket. Thus, it is a oversimplification to say that the Company has a history of chronic underspending. The Company invested $44.0 million more in 2020 than what was forecasted in Case No. U-20561 (approximately 5%, primarily due to higher-than-projected Emergent Replacements). Partly in response to the greater than projected spending in Emergent Replacements, there was a reduction in spending for Strategic Capital programs. The COVID-19 pandemic also had a significant impact on the Company's ability to perform strategic work in 2020, and the delay in filing this case (Crozier, 7 T 2348) makes a comparison to forecasted 2020 investments from Case No. U-20561 less relevant or useful than it might be under ordinary circumstances (Pfeuffer, 4T 243-244). Ms. Pfeuffer explained in part:

> As the COVID-19 pandemic impacted Michigan, the Company took immediate action to protect the health and wellbeing of its employees. Due to the limited knowledge regarding the impacts of the virus, the Company sequestered its employees doing critical job roles and used a home reserve program for all other field employees from mid-March 2020 to early May 2020. During this time, only emergent and system critical work was performed to ensure reliability. Because only emergent and system critical work was performed, all strategic work was paused. This action protected our employees' health but resulted in lost labor hours and not completing as much strategic work compared to the original plan. The Company's response was also consistent with the series of stay-at-home and workplace safety orders issued by Governor Whitmer following the March 10, 2020 EO 2020-04 declaring a state of emergency in Michigan due to the novel coronavirus pandemic [Pfeuffer, 4T 245, citing Executive Orders.]

The PFD, p 171, also acknowledges that "[i]t is true that the pandemic hampered DTE's ability to implement its plan in 2020."

For additional general background, see DTE Electric's Initial Brief, pp 53-60, which explained and supported the Company's projected DO capital expenditures, including a discussion of DTE Electric's final 2021 Distribution Grid Plan (DGP; Exhibit A-23, Schedule M1), the Company's Global Prioritization Model (GPM, which is a benefit-cost analysis (BCA)), and the three key objectives that the Company is pursuing on behalf of its customers: (1) safety; (2) improving reliability; and (3) avoiding emergent costs. DTE Electric's planned Strategic Capital investments are focused in three areas: (1) Infrastructure Resilience & Hardening,[50] (2) Infrastructure Redesign and Modernization,[51] and (3) Technology and Automation.[52]

i. Infrastructure Resilience & Hardening

Infrastructure Resilience & Hardening addresses the grid impacts associated with more frequent severe storms, and focuses on hardening the system, addressing frequent outage circuits, and replacing aging infrastructure. The Company projects capital expense associated with these projects of $455.5 million for 22 months ending October 31, 2022, and $346.1 million for 12 months ending October 31, 2023 (Pfeuffer, 4T 289; Exhibit A-12, Schedule B5.4, page 8; Exhibit A-23, Schedule M4).

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[50] These projects and programs focus on hardening the system, addressing frequent outage circuits, and replacing aging infrastructure. Exhibit A-12, Schedule B5.4, page 8 provides details, with additional details at Exhibit A-23, Schedule M4 (Pfeuffer, 4T 277, 289).

[51] This area focuses on major projects that generally involve the construction of substations and the rebuilding of large portions of circuits. Exhibit A-12, Schedule B5.4, pages 9-10 provide details, with additional details at Exhibit A-23, Schedule M5 (Pfeuffer, 4T 277, 313).

[52] These projects and programs are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications. They meet current grid need and provide immediate benefits to customers, lay the foundation for grid modernization, and will support increased adoption of DERs and EVs. Exhibit A-12, Schedule B5.4, page 11 provides details, with additional details at Exhibit A-23, Schedule M6 (Pfeuffer, 4T 277, 347-348).

Witnesses for Staff (Becker, 8T 5410, 5415; Wang, 8T 2221) and the AG (Coppola, 8T 4759) suggested disallowances in strategic capital investments based on arbitrarily averaging historical levels of investments. The PFD states:

> [T]he Attorney General's recommendation to limit overall projected spending increases in this category to 20% is a reasonable recommendation. It does, however, lack the guidance associated with a more detailed review of the specific line items or subsets of line items. [PFD, pp 172-73.]

Thus, it appears that the PFD recommends not adopting the AG's proposal. The Company agrees with that outcome. To the extent anything remains of the AG's proposal, including the suggestion that it is a "reasonable recommendation," the Company takes exception for the reasons discussed below. The Company's responses to the AG are also recounted for completeness (although perhaps technically moot) because they provide a fuller understanding of why the Staff's similar proposal (which the PFD recommends) should be rejected.

Staff proposed a 15% disallowance ($39.854 million in the bridge period; $51.914 million in the test year), which is a calculated (and rounded up) "average percent underspend in the infrastructure resilience and hardening subprogram each year from 2020 and 2021 based on underspending in 2020 and 2021 compared to the forecast from Case No. U-20561 (Staff's Initial Brief, p 29; see also Becker, 8T 5410-5411). The PFD states:

> Similar to the discussion of the Attorney General's recommendation above, Staff's recommendation is reasonable under the circumstances. Staff's analysis does not unduly weight small projection errors, but instead, Staff has looked at the projections the company has made for the entire subcategory of infrastructure resilience and hardening. It is appropriate to consider the percentage overprojections from year to year, rather than looking at an overall average over multiple years. Even looking at these numbers on an overall average basis, the result is still approximately a 15% overprojection. This PFD finds that Staff's recommendation should be adopted, with the additional adjustments to the 4.8kV hardening and pole and poletop maintenance and modernization program adjustments discussed below in subsection ii and iii. [PFD, p 177. Footnote omitted.]

The Company disagrees, first noting that it proposed strategic capital investments based on identified customer and grid needs (Pfeuffer, 4T 406; Exhibit A-23, Schedule M1). The Staff (and AG's) methodology (average of percentages spent on projects) is also flawed and produces skewed results by ignoring the relative size of the projects (*e.g*., a small project has an outsized effect on the resulting calculation). Rather, if an average percentage is to be used at all (which it should not be), it should be a weighted average, which is a far more accurate methodology. Exhibit A-41 Schedule FF1 is an illustrative example of how averaging percentages can lead to vastly different results when comparing the same dollar values and can state an overinvestment when an underinvestment actually occurred. The example shows how investing $910 million against a forecast of $1,100 across two years can provide an under-investment of 50% in one case and an over-investment of 40% in the other case, with the same total true investment of $910/$1,100=83% in both cases (Pfeuffer, 4T 407-409).

The Staff (and AG's) methodology is also unreasonable because it is based on 2020 and 2021, each of which had unique circumstances that impacted planned strategic investments. The Company made its plan prior to the unexpected pandemic, which caused statewide shutdowns that impacted DTE's ability to perform work in 2020, and corresponding delays continuing into 2021 (Pfeuffer, 4T 243-245, 409). Also, in the summer of 2021, the Company experienced a back-to-back series of historic severe weather events that caused a high volume of statewide outages (Pfeuffer, 4T 257-262). Therefore 2020 and 2021 are not a reliable predictor of the Company's ability to invest in strategic capital (Pfeuffer, 4T 409-410).

Company witness Pfeuffer explained the Company's consistent and appropriately cautious approach to dealing with the COVID-19 pandemic:

> As the COVID-19 pandemic impacted Michigan, the Company took immediate action to protect the health and wellbeing of its employees. Due to the limited

> knowledge regarding the impacts of the virus, the Company sequestered its employees doing critical job roles and used a home reserve program for all other field employees from mid-March 2020 to early May 2020. During this time, only emergent and system critical work was performed to ensure reliability. Because only emergent and system critical work was performed, all strategic work was paused. This action protected our employee's health but resulted in lost labor hours and not completing as much strategic work compared to the original plan. [4T 245.]

The Company similarly disagrees with the AG for four reasons. First, the Company's proposed investments are based on customer and grid needs as indicated above (Pfeuffer, 4T 406; Exhibit A-23, Schedule M1). Second, the AG's analysis arbitrarily begins with 2017, omitting the 36% increase from the 2016 year (Exhibit A-41, Schedule FF18). The PFD states it was "disingenuous" for the Company to criticize Mr. Coppola for beginning his analysis using 2017 where it "stated in discovery that comparable numbers were not available for 2016 and did not provide them for any of the lines in schedule B5.4, page 1, including total strategic capital spending." (PFD, p. 170). However, while the Company did not provide the 2016 data broken down by individual project for 2016, as it was requested in that particular discovery request, DTE Electric did provide data from 2013 forward, that included total strategic capital spending. The PFD overlooked that this information was provided in response to discovery STDE-1.67-01 Historic Capital by Category, which was also included in Exhibit A-41 Schedule FF18. Exhibit A-41 shows the 2013-2021 strategic capital in the three subcategories, Resilience and Hardening, Redesign and Modernization, and Technology and Automation. The AG witness only looked at total strategic investments to develop his disallowance proposal, for which he could have used the provided data to start at 2016, which is when DTE Electric started to increase investments in strategic capital. Third, unique circumstances (pandemic and storms), as indicated above (Pfeuffer, 4T 409-410), severely impacted two of the years in the AG's analysis (2020 and 2021). Fourth, the AG's focus on strategic capital neglects the Company's total ability to execute capital investments. The Company's compound annual growth rate for total capital was 23% for 2016-2019 and is still 16% even when

including the pandemic-impacted 2020 (Exhibit A-41, Schedule FF19), so the Company's currently proposed 17% rate for total capital is well within the historic range. If the Commission decides to look at strategic capital alone (i.e. separately from all DO capital expenditures), then the most accurate view is provided by the 2016-2019 compound annual growth rate of 33%, which is slightly less than the Company's proposed 39% (Pfeuffer, 4T 416-419).

AG witness Coppola also indicated concerns about supply chain issues and opined that "[u]nder these circumstances, achieving the 2021 level of capital spending on strategic programs would be a challenge. Attempting to double the size of the programs in 2022 and 2023 would seem even more challenging and unreasonable" (8T 4759). The Company agrees that it proactively identified lead time delays on construction materials and expects these delays to continue, as it stated in response to discovery (Exhibit A-41, Schedule FF2); however, Mr. Coppola took those sentences out of context, by failing to include the final paragraph of the discovery response, which describes steps that the Company has taken to mitigate these delays going forward. These mitigation actions have been successful, and reduce supply chain risk going forward (Pfeuffer, 4T 412-413, 421).

Mr. Coppola further asserted that "[i]n the current labor market, the availability of those additional resources is questionable and if found will require higher wages, and higher labor and contractor costs, placing added strain on the capital budgets" (8T 4759). The Company disagrees because Mr. Coppola's assertion is based on two incorrect premises, the first being that doubling capital spending "means the number of labor resources… will likely need to double" (Coppola, 8T 4759), which is unsupported and unjustified, and second, as previously mentioned above, the total

amount of capital investment is not doubling[53] in the test year. The Company also has adequate plans in place to identify and address labor resource gaps and has demonstrated its ability to grow its workforce appropriately. For example, the average number of contract linemen employed daily was 308 in 2021, and 568 in April of 2022 (Pfeuffer, 4T 414-415, 420-421; Exhibit A-14, Schedule FF3).

Moreover, if the proposed disallowances of strategic capital investments were to be adopted, then there would be negative impacts on safety, reliability, and emergent costs, including (1) degradation of the system and increased equipment failures; (2) difficulty supporting economic development and customer growth, as overloaded circuits would not be addressed (further damaging equipment) and needed capacity would not be added; (3) the system would be less resilient to intense weather events; and (4) the system would not have the infrastructure or the technology to support further penetration of DER and EVs (Pfeuffer, 4T 287).

Therefore, the PFD's proposed 15% disallowance should be rejected.

a. 4.8 kV Hardening

This sub-program of Infrastructure Resilience and Hardening was developed as a cost-effective way of providing improvements in safety risks due to downed wires in a relatively short number of years, even as DTE Electric works to convert the 4.8kV system in the City of Detroit to a higher grid voltage as part of grid modernization. The conversion program is estimated to cost over $4 billion and take more than a decade to complete. Primary components of the program include removing Detroit Public Lighting Department (DPLD) arc wire (consistent with the Commission's Order in Case No. U-18484) and DPLD distribution wire from DTE Electric-owned

[53] The proposed increase in total capital for distribution operations is 17%, and the increase in strategic capital only is 39%, (Pfeuffer, 4T 416-419).

equipment, removing service lines to abandoned properties, replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, and trimming trees to support construction activities (Pfeuffer, 4T 291, 423-424). In DTE Electric's last rate case, the Commission previously agreed with the ALJ, who "agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit" (May 2, 2019 Order in Case No. U-20162, pp 31, 33).

In the Company's last general rate case, the Commission recognized that various indicated concerns were substantially addressed in Case No. U-20162 but directed the Company to "provide a more detailed explanation of the factors and scoring process the company uses to prioritize the circuits to be hardened" (May 8, 2020 Order in Case No. U-20561, p 110). Accordingly, Ms. Pfeuffer explained that DTE Electric prioritizes the order in which it addresses the different sections of the 4.8 kV system based on numerous criteria, including safety and reliability performance, with safety being the primary driver in the prioritization efforts. The Company prioritizes work at the substation level because it is efficient to plan and perform work for the group of circuits tied to the same substation. The Company scored each substation in Detroit based on: (1) Recorded wire downs per overhead line mile; (2) Estimated foot traffic within the substation service area; (3) Total substation SAIDI; and (4) Total outage and non-outage events requiring the dispatch of a line crew. The scores for risk reduction, reliability improvement, and cost management are normalized and combined to provide an aggregate score, with greater weight given to risk reduction (45% risk reduction; 27.5% reliability improvement; 27.5% cost management) (Pfeuffer, 4T 292-293).

The Company has successfully hardened over 600 line-miles and expects to harden close to 1,600 miles over the next five years. This is appropriate because the Company provided compelling

evidence that the program has resulted in improvements in safety due to reduction in downed wires as well as reliability improvements in circuits that have been hardened, when compared to control group circuits that have not been hardened (Pfeuffer, 4T 293-297, 426). Moreover, the 4.8 kV hardening will deliver safety and reliability improvements faster than 13.2 kV conversion alone could (Pfeuffer, 4T 295).[54]

The PFD adopted arguments raised by MNSC that discount the safety measures incorporated into the 4.8kV hardening program. The PFD states "While not dispositive as to the merits of DTE's program, this PFD finds MNSC's argument that the Commission never ordered DTE to remove arc wire in Case No. U-18484 well supported." Rather, it is the PFD's conclusion that the Commission has not required the Company to remove arc wire that not well founded. The road to get to the Commission's order in U-18484 which MNSC and the PFD cite, is a complicated one – which these exceptions walk through below, and the culmination of which was an order for DTE Electric to submit a plan for approval by the Commission to "address" dangerous arc-wire, and subsequent approval of such a plan.

In the Commission's September 23, 2016 order in Case No. U-18172, a docket opened by the Commission to, in part, investigate circumstances where abandoned Detroit Public Lighting Department power lines became energized after contacting DTE Electric power lines. The Commission ordered the Company to work with the Commission's staff to "protect the public and to remedy any similar circumstances where abandoned power lines could become energized" and required reporting. MPSC Case No. U-18172, September 23, 2016 Order, p 3. Subsequently the Staff submitted a report noting that DTE and DPLD had made strides in ensuring that when DTE

[54] While approximately 14% of the Company's customers are located in the City of Detroit, the Company is investing approximately 29% of its 2021-2023 Strategic Capital in the City of Detroit to address aging infrastructure and improve safety and reliability, and these significant investments will continue in future years (Pfeuffer, 4T 298-299).

was notified of DPLD downed wires, and made referrals to DPLD, that those reports were followed up on by DPLD in a timelier fashion. Despite these improvements, the Staff noted that "Only the future removal of the arc wire will entirely eliminate the safety threat posed by the arc wire system to the residents of the City of Detroit." MPSC Case No. U-8172, November 23, 2016 Staff Arc-wire Report, p 7.[55] The Staff recommended that DTE begin making annual reports to the Commission regarding the progress of addressing the threat of arc-wire in conjunction with the City of Detroit, which the Company did on September 1, 2017. DTE Electric outlined the progress of two pilots, one where DLPD removed arc-wire and the other where DTE Electric removed the arc-wire. During the pilots, it was determined that rebalancing of cross-arms and/or replacement of crossarms was necessary following removal of arc-wire. MPSC Case No. U-18172, September 1, 2017 DTE Electric Company's 2017 Annual Report, pp 1-3. Shortly thereafter, on December 7, 2017, the Commission entered its order closing the investigation and concluding that "out-of-service arc wire presents a potential safety hazard to the residents of Detroit." The Commission also stated that it was "concerned about the potential hazard posed by out-of-service arc wire that may come in contact with energized DTE Electric facilities." MPSC Case No. U-18172, December 7, 2017 Order, p 6.

In that case, the Commission determined that DTE working with the Detroit Public Lighting Department's (DPLD) via "Make Safe" programs "while an improvement, are short-term and reactive, and do not address the long-term problem of out-of-service arc wire in Detroit." *Id.* The Commission noted that "A full resolution may involve the eventual removal and/or isolation of all

[55] Staff also noted that "As owner of the PLD assets, it is the City of Detroit's responsibility to remove abandoned arc wire and it has presented a cost estimate to remove that wire, but has provided no commitment to implement a plan to remove it." *Id.*

arc wire, a daunting task because the complex system spans the entire city of Detroit and some outlying areas."

On the same date as it closed its initial investigation, the Commission opened a new docket, in Case No. U-18484, *In the matter, on the Commission's Own Motion, to address out-of-service ARC Wire in the City of Detroit.* In its order opening the new docket, the Commission explained that it had opened the docket to follow up on its order of same date in U-18172, which "ordered that a comprehensive effort be undertaken to avoid similar incidents and improve safety within the city of Detroit ***by removing potentially hazardous, out-of-service arc wire***." MPSC Case No. U-18484, December 7, 2017 Order, p 1. The order discussed the challenges of dealing with arc-wire and ordered the Company to assess Detroit arc-wire and then "develop a detailed report of the results, including cost projections, the priority of work to be completed, and the potential for coordination with related activities, such as general distribution system modernization efforts." *Id.* at 4-5. The Commission emphasized that "Safety must continue to be a focus. If particularly hazardous areas are identified, those areas should be prioritized as part of the plan." *Id.* at 5. The Commission also required progress reporting. DTE Electric sought rehearing, arguing that it "does not own, operate, or have any legal rights or obligations whatsoever to the DPLD arc wire." MPSC Case No. U-18484, March 15, 2018 order, p 2. And, while the Commission stated its December 7 order was not to be interpreted as a "directive to remove the arc wire," (*Id.* at 4) the Commission also expressed its expectation that DTE address it somehow, and soon:

> Nevertheless, there is a sense of urgency in dealing with the arc wire, in that lives may be harmed or lost so long as the wire remains in proximity to DTE Electric's distribution system. DTE Electric must take a proactive approach. To be clear, the Commission is less concerned about prescribing the specific approach to identifying and remedying the potential hazards or directing DTE Electric's interactions with the City. But, in bringing about solutions to maintain its electric facilities in a manner that protects the safety of the public and its employees, the Commission believes it is essential that the company have a sense of urgency and commitment to address

> any safety concerns, collaborate with appropriate entities, and provide a transparent and risk-based assessment to cost-effectively address safety hazards. [*Id* at 5.]

The Commission also specifically contemplated including arc-wire removal in 4.8kv hardening. It stated: "Any methodology to address the hazard presented by the arc wire coming into contact with DTE Electric's facilities that is incorporated into its 4.8 kilovolt (kV) hardening program should isolate where the hazards are more pronounced and provide a prioritization of remediation that is commensurate with that risk." *Id.* The Commission concluded:

> It is imperative that DTE Electric work with the Staff, the DPLD, and other relevant entities to ensure the safety of DTE Electric's distribution system ***by facilitating the removal of arc wire wherever it presents a potential hazard to the residents of Michigan by coming in contact with DTE Electric's equipment***. For reasons set forth in this order and in the December 7 order, maintaining proper line clearances and the safety of DTE Electric's electric distribution system are too important to be left to "working in good faith." [*Id.* at 6 (emphasis added).]

DTE Electric filed its plan to address arc-wire on March 29, 2018, Staff filed its report on July 31, 2018. The Commission noted in its subsequent order on September 28, 2018, that "In evaluating DTE Electric's planned remedial actions, the Staff considered whether the plans are adequate to meet regulatory and statutory requirements. The Staff states its belief that '***arc wire removal is necessary to operate in a safe manner and maintain compliance*** with Michigan Administrative Code Rules 460.3801 and 460.3505.' Staff's report, pp. 3-4." MPSC Case No. U-18484, September 28, 2018 Order, p 3 (emphasis added). The Company incorporated Staff concerns into its revised report, filed March 29, 2018. The Commission stated that it

> [R]emains firm that the dangers posed to the public by abandoned arc wire juxtaposed with overgrown vegetation, obstructed or limited access to alleyways, and the declining ungrounded 4.8 kV system are not acceptable… ***Appropriate integration of arc wire removal*** with other DTE Electric programs, such as the hardening and conversion programs, is a crucial aspect of planning and executing strategies. [*Id.* at 6 (emphasis added).]

The Commission did not specifically order the Company to implement its proposed plan or order rate recovery for the plan, preferring instead "to address these issues, including performance

expectations and cost recovery, in DTE Electric's pending rate case." *Id.* The Commission nonetheless made its intent clear: "However, the Commission emphasizes that DTE Electric is expected to continue to make significant efforts to address safety risks associated with arc wire coming into contact with its distribution system, concurrent with aggressive vegetation management, and hardening and conversion of the ungrounded 4.8 kV system." *Id.* at 7. The currently pending rate case at the time was DTE's U-20162, wherein the Company reiterated, and the Commission approved DTE Electric's plan for arc-wire removal as part of rate recovery for the 4.8kV hardening program (MPSC Case No. U-20162, May 2, 2019 Order, p 32-33). The PFD/MNSC's position on arc wire invites an improvident outcome. Regardless of the nuances of arc wire, the Commission has indicated its expectation that DTE Electric remove the old DPLD arc wire,[56] and the Company is doing just that, expeditiously and safely.

MNSC witness Ozar suggested that the Commission maintain the same level of annual spending in 4.8kV hardening as in 2021 (8T 3984). The PFD states:

> This PFD concludes that the Commission should adopt MNSC's recommendation to limit DTE's expenditures on hardening until a proper analysis of hardening versus enhanced tree trimming can be made. Mr. Ozar's testimony is clearly correct: DTE did not adequately control for tree-trimming in its hardening analysis…

The cornerstone of the PFD/MNSC's recommendation is Mr. Ozar's suggestion that "an effective tree trimming program targeting the worst-performing 4.8kV lines would achieve significant reliability improvements, at a lower cost to ratepayers" (Ozar, 8T 3978). This narrow focus neglects that tree trimming alone will not remove the DPLD-owned arc wire that is a core safety benefit of the hardening program or address the aged pole and pole top equipment in Detroit circuits. Disaggregating the 4.8kV Hardening program and raising doubts about individual parts (or

[56] MPSC Case No. U-18484, December 7, 2017 Order, p 5; March 15, 2018 Order, p 6.

suggesting that the parts should be pursued individually instead of coordinated in the program) neglects that the program is a well-designed and approved multi-part program that has achieved success and continues to be appropriate, as indicated above.

Mr. Ozar narrowly focused on reliability benefits of the program, incorrectly assuming (as apparently did the PFD) that the 4.8kV Hardening program only targets the worst-performing substation areas in Detroit. Instead, as indicated above, the prioritization methodology targets safety (wire downs and foot traffic) in addition to performance and reliability (Pfeuffer, 4T 292, 427). The Company also cannot just remove arc wire without other pole top work because that would leave cross arms dangerously unbalanced. When line workers remove arc wire, they must also rebalance and properly support the remaining wires. The 4.8kV Hardening program is fully developed, well supported in past cases, efficient, and providing immediate safety and reliability benefits for customers.

Mr. Ozar and the PFD also fail to correctly analyze the Company's comparison of performance following hardening, as compared to lines that have not been hardened. Mr. Ozar's analysis is flawed in several respects. First, Mr. Ozar neglects that the analysis DTE Electric presented compared the performance of the 28 hardened circuits to 153 circuits unhardened circuits, not just the 55 Mr. Ozar discussed. The 153 circuits included 55 overhead lines with tree trim dates, and also included 69 underground lines, and 29 lines which have since been reconfigured, or decommissioned. [57] The performance averages the Company compares include the performance of all these circuits, including even those without risk of a downed wire. Second, Mr. Ozar claimed in his comparison that all of the 28 hardened circuits had been trimmed in 2019 or more recently.

[57] In his testimony, at Ozar, 8T 3975, the witness references MNSCDE-9.37cxi in footnote 40, which provided the data for the 153 included circuits.

In actuality, 8 circuits, or nearly a third of the circuits, had been trimmed in 2018.[58] Finally, and critically, Mr. Ozar neglected that the tree trim report numbers he used for comparison are not a complete picture of all downed wires on those circuits – rather, they are only those downed wires that were caused by trees (MEC-97, p 5 regarding "Methodology Used to Calculate ETTP Performance" the narrative explains "*ETTP Performance…uses the average of three years of… tree-outage events,*" and p 9 regarding wire-down performance calculated "*Using the same methodology discussed above*"). The comparison the Company used for hardening included all causes, including overhead equipment failures, which account for approximately 25% of all events, including downed wire events (Pfeuffer, 4T 305). Cumulatively, the effect of these differences means that the Company's analysis provides a more accurate picture of the performance of the program when measured against the remaining un-hardened system.

Therefore, the PFD's recommendation to adopt MNSC's proposal to cap the 4.8kV Hardening program at the 2021 investment level should be rejected.

The PFD further states:

> This PFD further recommends that the Commission adopt Staff's recommendation to require DTE to explore, with some urgency, alternatives to convert the circuits. While Staff requests that the company analysis be complete by the time of its next rate case filing, this PFD concludes that a collaborative or other forum would be a preferable approach to explore options outside of the constraints of a 10-month rate case, which DTE could file within 2 months of a Commission order in this case with little time for the anticipated analysis. [PFD, p 194.]

The Company disagrees that exploring alternatives to the current 4.8kV Hardening program is necessary or appropriate but agrees that a collaborative or other forum would be a preferable venue if the Commission wishes to explore the PFD's suggested issue. Again, this program has already

[58] In his testimony, at Ozar, 8T 395, footnote 41, the witness references MNSCDE-9.37bxi, which shows that 8 of the Hardened circuits were trimmed in 2018 not 2019 or after.

received considerable attention. The Commission previously approved rate recovery for the program agreeing with the ALJ in that case, who "agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient" and that a "more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit" in the short term (May 2, 2019 Order in Case No. U-20162, pp 31, 33). Conversion will take many years, and 4.8kV hardening provides many of the safety and reliability benefits of conversion much more quickly. In the Company's last general rate case, the Commission stated that it "concurs with the ALJ that Soulardarity's concerns were largely addressed in Case No. U-20162" (May 8, 2020 Order in Case No. U-20561, p 110). [59]

Ms. Pfeuffer also provided a broad discussion of Energy Justice (Pfeuffer, 4T 505-21), including corrections to various apparent misperceptions regarding the 4.8kV system, explaining for example that most areas of the system have sufficient capacity to incorporate some level of EVs and DERs, and that hardening does not in itself delay the conversion to 13.2kV (Pfeuffer, 4T 508-509, 119).

Therefore, the Company maintains that the 4.8kV Hardening program is appropriate, fully supported by data-driven results, and should be approved as proposed.

b. Pole and Pole Top Maintenance and Modernization (PTMM).

This program proactively identifies and replaces damaged or defective equipment before unexpected failures occur (Pfeuffer, 4T 301). The Company inspects poles on a 10- to 12-year cycle. Results from these patrols have typically shown that approximately 8% of the total poles

[59] Issues fully decided in earlier MPSC proceedings need not be relitigated in later proceedings unless a party presents new evidence or shows by changed circumstances that the earlier result is unreasonable. *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1, 420 NW2d 156 (1988).

inspected have reduced strength and need remediation (Pfeuffer, 4T 302). The Company is increasing its investments in this program due to enhancements made to the program specifications based on benchmarking and learnings from other key programs, in support of greater reliability and resiliency. The enhanced pole inspection specification and process align with industry best practices and will reduce the risk of pole failures, improve customer reliability, and reduce reactive costs during trouble or storm events. Customers will benefit because overhead-equipment related outages account for almost 25% of all events. As a result of the planned improvements to the Pole/PTMM program, the Company expects a reduction in equipment-related outage events, which will drive reliability improvements, reduce reactive costs, and improve safety by reducing downed wires (Pfeuffer, 4T 303, 124-125).

MNSC witness Ozar proposed to cap the Pole/PTMM program at the 2021 investment level (disallowances of approximately $15.7 million for the 10 months ending October 31, 2022; $54.3 million for the test year), indicating disagreements with the Company's reasons for increasing investments (8T 3989-3997). The PFD states:

> This PFD finds Mr. Ozar's testimony persuasive. DTE was not clear regarding its standards for remediation versus replacement. It also has not explained the basis for its cost projections. Looking at the tables in Mr. Ozar's testimony at 8 Tr 3991, the company is projecting an approximately 6% increase in pole inspections between 2022 and 2023, yet is projecting a 60% increase in total cost, and a70% increase in the "modernization" component of its total cost. The data from Exhibit MEC-101 is further confounding because it seems to show no basis for the company's cost increases over 2019 levels. DTE did not refute Mr. Ozar's testimony that the company has been using an upgraded pole class at least since Mr. Bruzzano's direct testimony was filed in Case No. U-20162 [citing 8T 3994, n 84]. Nor did DTE refute Mr. Ozar's testimony regarding the equipment failures that cause outages. Reviewing the evidence, it appears that DTE's program is unsupported by credible projections.
>
> Similar to the adjustment above, this PFD computes the additional amount needed to reduce the 10-month bridge and test year projections to an annual expense level of $33.4 million, the 2021 expense level included on line 10 of schedule B5.4, after Staff's 15% reduction is taken into account. The result is an additional reduction of

> approximately $13.9 million to the 10-month bridge and a reduction of $41.1 million to the test year. To clarify, after Staff's adjustment and the additional adjustment recommended in this subsection, the 10-month bridge expense level included in rate base will be $27.9 million (10/12ths of $33.44 million) and the test year expense will be $33.44 million. [PFD, pp 200-201.]

The Company maintains that its reasons are valid and fully support its proposed level of funding, as indicated above and further discussed below.

First, the Company has a goal of achieving a 10-year inspection cycle using only the Pole/PTMM program (instead of also relying on the 3rd party pole inspection process) because (1) inspections under the Pole/PTMM program are now performed to an updated, more robust standard; (2) benchmarking showed that a 10-year inspection cycle (or less) was industry best practice; and (3) the Pole/PTMM program will efficiently meet the Staff's 10- to 12-year cycle recommendation (Pfeuffer, 4T 430).

Second, the Company changed its pole inspection process to specify pole testing (instead of visual inspection alone) for poles 20 years or older. Thus, more poles are now inspected for below-grade decay that is not visible in above ground visual inspections. This results in the identification of more poles requiring replacement or remediation, and a corresponding increase in capital to replace or reinforce these poles (Pfeuffer, 4T 431).

Third, a change in pole specifications has increased the strength of new poles by a factor of more than 2.5. And while the PFD notes that "DTE did not refute Mr. Ozar's testimony that the company has been using an upgraded pole class at least since Mr. Bruzzano's direct testimony was filed in Case No. U-20162 [citing 8T 3994, n 84]" (PFD, p 200), Witness Pfeuffer also testified that, nevertheless, only about 12% of the Company's current poles are higher-class poles called for in the updated specification, meaning 88% of poles remain at a lower class. Customers will receive safety and reliability benefits from stronger poles that are more resilient to storms and wind

(Pfeuffer, 4T 251, 432). Witness Ozar himself noted the importance of the program when he suggested that DTE Electric should be on a 5-yr cycle (Ozar 8T 3997/3998).

The PFD also appears to neglect that, as the Company said when introducing this topic, the program proactively identifies and replaces damaged or defective equipment *before unexpected failures occur* (Pfeuffer, 4T 301). Nearly 30% of the Company's poles are now more than 60 years old, with an industry life expectancy of 40-60 years (Exhibit A-23, Schedule M1, DGP p. 176). The Company disagrees with suggestions that it should wait for pole failures before acting. Failing poles put customers and linemen at risk when they break and cause outages that are sometimes difficult to repair; discovery of below grade decay (and subsequent replacement) prevents poles from failing (Pfeuffer, 4T 256, 301, 305). There is simply no merit in MNSC's overall theme that the Company is being overly "proactive" (*e.g.*, PFD, pp 164-66; MNSC Initial Brief, pp 31, 58).

The PFD's suggestion that "DTE was not clear regarding its standards for remediation versus replacement" similarly neglects the record and the nature of the work. In addition to the discussion above, Ms. Pfeuffer further explained that the Company has placed a greater emphasis on replacing outdated equipment rather than repairing it but does not require replacement. The decision to repair or replace is often made in the field by line workers, depending on factors including the amount and type of damage, and field conditions that affect the difficulty of a repair or replacement during storm or emergent conditions (Pfeuffer, 4T 250-251, 498).

Therefore, and as further discussed on the record, the PFD/MNSC's proposed investment cap should be rejected, and the Pole/PTMM program should be fully funded.

ii. Infrastructure redesign and modernization.

Infrastructure Redesign and Modernization focuses on major projects that generally involve the construction of substations and the rebuilding of large portions of circuits. The Company

projects capital expense associated with these projects of $307.5 million for 22 months ending October 31, 2022, and $314.3 million for 12 months ending October 31, 2023 (Pfeuffer, 4T 313; Exhibit A-12 Schedule B5.4, page 9, line 89, columns (f) and (g); Exhibit A-23, Schedule M5).

Staff proposed a 40% disallowance ($70.958 million in the bridge period; $86.034 million in the test year) based on underspending in 2020 and 2021 compared to the forecast from Case No. U-20561, similar to Staff's proposed percent disallowance for Infrastructure Resilience and Hardening (Becker, 8T 5415-5416), discussed above. The PFD states:

> This PFD finds Staff's analysis persuasive and recommends that its recommendations be accepted, including the additional adjustments discussed in subsections ii and iii below [PFD, p 203.]

The Company disagrees because the Company fully supported the reasonableness and prudence of the projects, and Staff did not contend that any of the projects are not reasonable or prudent, or that they will not provide customer benefits. Staff simply relied on a methodology that is flawed for four reasons discussed above (in summary: (1) historic spending should not be used to forecast future strategic capital need; (2) the "average of percentages" methodology is flawed; (3) 2020 and 2021 had unique circumstances, and (4) the Company has instituted changes that will improve its planning and project execution) (Pfeuffer, 4T 433-434).[60]

Therefore, the Commission should not accept the PFD and Staff's proposed 40% disallowance.

a. Subtransmission Redesign & Rebuild.

DTE Electric's Subtransmission system is operated at a mid-level voltage of 24 kV, 40 kV, or 120 kV, and is used to step down transmission voltage to serve distribution and industrial

[60] If an average method is adopted (which it should not be), then it should be based on the Company's analysis, which in this category would result in disallowances slightly less than Staff suggests (Pfeuffer, 4T 434; Exhibit A-41, Schedule FF4).

substations. The Subtransmission Redesign & Rebuild program focuses on installing new station equipment and rebuilding both the overhead and underground portions of the subtransmission system. The program is needed to increase capacity for loads from existing and new customers, support DER interconnections, and improve reliability due to aging equipment. Benefits include safety improvements, improved reliability and operability, and increased capacity (Pfeuffer, 4T 315-323).

Staff proposed a complete ($2.917 million in the test year) disallowance for Small projects & Reserve (Exhibit A-12, Schedule B5.4, page 9, line 36), characterizing it as premature and inadequately supported (Becker, 8T 5414-5415). The PFD states:

> This PFD finds Staff's argument persuasive that DTE did not adequately support this line item, providing conflicting information that was not reconciled with earlier information. [PFD, p 207.]

The Company disagrees because it identified and supported actual projects that are needed to support grid reliability for 2023, as stated in response to discovery (Exhibit A-41, Schedule FF5) and Exhibit A-23, Schedule M5, pages 140-43 (Pfeuffer, 4T 435-436). The PFD (at p 206) was apparently concerned that Exhibit A-23, Schedule M5 refers to four projects, but STDE-25.16, Exhibit A-41, Schedule FF5 refers to six projects. The PFD neglects Ms. Pfeuffer's testimony that "STDE-25.16, Exhibit A-41 Schedule FF5, was the final and correct response that meant to correct the record" (4T 436). Therefore, the projects are supported, and their costs should be approved. Though mistakes are regrettable, they can happen. The Company should not be held to testimony that it has indicated was made in error. When the Company calls out an error and corrects it,

correcting the error does not create ambiguity – the corrected testimony or discovery supersedes the prior incorrect statements, and should be treated as such.[61]

b. Strategic Undergrounding Pilots

The Company's strategic undergrounding pilots seek to understand the viability of undergrounding in a number of different technical scenarios to address grid resiliency challenges. The Company received feedback from customers and the Commission following 2021's historic storm season which had a significant number of overhead outages to determine whether undergrounding might provide a solution to alleviate weather-related outages including those caused by trees impacting overhead infrastructure. In addition, and as explained more fully in the Company's DGP (Exhibit A23, Schedule M1), one of the planning scenarios contemplates the anticipated long-term effects of climate change (increasing temperatures and frequency of catastrophic storms) on the distribution grid. One option for addressing this scenario is undergrounding in some circumstances to improve reliability as compared to overhead

[61] This argument is similar to an argument made by Staff in DTE Electric's last rate case, Case No. U-20940. *See, e.g.* MPSC Case No. U-20940, December 9, 2021 Order, pp 127-128. In that case, the Company asked for O&M expense for nine meter read employees. The Staff proposed a disallowance for expenses associated with eight employees, based upon a report and a discovery response from the Company stating that the Company only employed one meter reader. MPSC Case No. U-20940, September 28, 2021 PFD, p 179. In rebuttal, the Company's witness corrected the error testifying that there are nine meter read staff – one meter reader, and eight meter read staff employees who perform back office, customer service, and meter analysis functions. *Id.* at 180. In briefs, the Staff stood by its disallowance, indicating the conflicting testimony provided ambiguity and if there was an error it was DTE's in providing an unclear discovery response. *Id.* at 181. The PFD found persuasive the Company's corrections made in discovery and rebuttal (one meter reader and eight meter-reading staff). *Id.* at 182. The Commission agreed with the ALJ:

> DTE Gas proposed a $5,349,000 O&M expense for nine meter read employees. Exhibit A-13, Schedule C5.4. The Staff proposed a disallowance of $1,603,493… In rebuttal, the company explained that the proposed expense relates to all nine meter read staff and not just the sole meter reader… The ALJ found DTE Gas's rebuttal persuasive and recommended that the Commission reject the proposed disallowances… Therefore, the Commission adopts the findings and recommendations of the ALJ in adopting the company's $5,349,000 O&M expense pertaining to meter reading. [MPSC Case No. U-20940, December 9, 2021 Order, pp 127-128.]

Both the Commission and the ALJ in that case agreed that when the Company corrected its error, doing so does not create conflicting testimony or ambiguity.

construction. The pilots seek to test whether undergrounding is a viable solution to current weather-related outage frequency, and a potential solution in the event of even greater increases in catastrophic storm frequency in the future, since underground infrastructure is less susceptible to wind/weather conditions than is overhead. On the other hand, underground construction cost is higher, undergrounding does not completely eliminate the potential for outages, and outages in underground systems might take longer and be more costly to locate and repair. Thus, the Company must thoughtfully implement Strategic Undergrounding to balance the benefits with the challenges. Pilots will help develop and refine analysis of overall life cycle costs and criteria for Strategic Undergrounding (Pfeuffer, 4T 336-340). The PFD does not mention that the Commission specifically asked utilities to consider undergrounding, asking "Are there potential utility pilots or industry best practices that can improve customer safety and reliability by moving overhead lines on specific circuits or in segments of the electric distribution system underground at reasonable costs?" (August 25, 2021 Order in Case No. U-21122, p 10). The pilots proposed here will also allow the Company to fully answer the Commission's inquiry.

In addition to completing the currently ongoing Appoline DC 1346 pilot, the Company is developing a balanced set of pilots with two approaches to undergrounding: (1) Replacing overhead services with underground services; this pilot will begin in 2022 if recovery is approved (see Exhibit A-12, Schedule B5.4.2 for details), and (2) replacing both overhead laterals and services with URD. For this second pilot, the Company plans to relocate rear-lot overhead assets to front-lot URD on a portion of a Fairmount circuit in Detroit (Pfeuffer, 4T 341-343). Replacing laterals has the additional benefits of preventing overhead primary wires down and preparing for eventual conversions to higher voltages for the areas. Focusing on both lateral and service pilots provides a

balanced approach that will provide information that is necessary to identify the most benefits for customers while also considering the cost of the work (Pfeuffer, 4T 343-344).

The PFD proposed a complete disallowance, stating

> This PFD finds that the spending for continuation of this program should be rejected at this time, for the reasons articulated by Mr. Becker, Mr. Ozar, and Mr. Coppola.
>
> …
>
> This PFD concludes that DTE has not established that its proposed pilots are reasonable and prudent, or that it has a credible cost estimate or timeline for the work it proposes to undertake. [PFD, pp 218-19.]

The Company disagrees as discussed below in the context of responding to testimony that apparently persuaded the ALJ.

Staff proposed disallowances ($15,100,000 (of $17,248,000) for the ten months ending October 31, 2022; the entire $36,783,000 for the test year) reasoning that "capital expenditures for new undergrounding pilots should not be put into rates until the Appoline DC 1346 pilot is completed, and the results known and analyzed" (Evans, 8T 5430). The Company disagrees because the Appoline DC 1346 pilot is essentially complete, and the Company has gained key learnings that it is using for the new Strategic Undergrounding pilots (Pfeuffer, 4T 339, 438-440, 449).

Staff further reasoned that "[u]ndergrounding existing overhead lines is far more expensive than building overhead lines, so the potential for undergrounding being a cost-effective solution for DTE Electric's service territory is likely quite limited" (Evans, 8T 5431). The Company disagrees that the potential for undergrounding is this "limited." The Company can obtain cost advantages of larger scale by increasing the volume of its Strategic Undergrounding work. There are also safety and reliability benefits beyond construction cost (Pfeuffer, 4T 343, 440-443). Witness Pfeuffer explained that the "Company's view of Strategic Undergrounding is that it is a well-suited option for circuits that consistently experience outages and down wires, despite regular maintenance including tree trim." (Pfeuffer, 4T 441) She explained that the Fairmount DC 1593 circuit provides

an example, where "many downed wires are still occurring even after tree trimming has been completed." She explains that "Considering the importance of reducing down wires and the fact that the most effective storm resiliency program, tree trimming, did not correct the situation; a circuit reconfiguration countermeasure is needed." (Pfeuffer, 4T 441) This pilot will test this solution as on option for addressing these types of high-trouble circuits.

The PFD neglected these considerations beyond cost even though Local 223, the workforce that helps to address customer outages today and which will be involved with rebuilding parts of the grid underground in the future, agreed with the Company and supports the undergrounding pilots, explaining in part:

> [T]he Union submits that undergrounding will also protect the lives and safety of the public and utility workers…
>
> The benefits of undergrounding warrant further exploration. This can be accomplished through the Company's pilots. Undergrounding programs must be further developed to safeguard the safety and welfare of the public and the Company's workforce. [Local 223 Initial Brief, pp 1-2.]

AG witness Coppola proposed a complete disallowance (8T 4763-4764). In addition to the discussion above, the Company disagrees with the three reasons that Mr. Coppola suggested for his proposal. First, he suggested that the same process used on the Appoline pilot will be repeated on the proposed pilots. To the contrary, there is a major difference in scope and approach between assets being relocated from rear-lot overhead to rear-lot underground (Appoline pilot) versus rear-lot overhead to front-lot underground (Fairmount DC1593 pilot) (Pfeuffer, 4T 444; Exhibit A-23, Schedule M1, pp 344, 350). Another significant difference is a greater level of effort and proactiveness for customer engagement in the proposed pilots (Pfeuffer, 4T 444-445, 447; Exhibit A-23, Schedule M1, p 346). Finally, the pilot for undergrounding services[62] differs from the

[62] "Services" refers to individual service drops that connect a single customer location to a nearby distribution line.

previous pilot because it is focused strictly on undergrounding customer service feeds (Pfeuffer, 4T 445; Exhibit A-23, Schedule M1, pp 349-51).

Mr. Coppola further suggested that DTE Electric has not considered what other utilities have done, and not identified new lessons to be learned (8T 4763). To the contrary, the Company has learned from continued benchmarking as well as the Appoline pilot to test more cost-effective methods and customer-engagement approaches, which will enable further learnings regarding scalability and cost efficiency. The Company is also interested in assessing the improvement potential that undergrounding services has on overall storm restoration times. Finally, if the results of the services pilot show that it is cost effective and results in enhanced reliability for customers, then the pilots might be expanded, or be suitable for widespread adoption (Pfeuffer, 4T 342, 445-447, 349; Exhibit A-23, Schedule M1, pp 346, 349, 356).

The discussion above also essentially applies to MNSC witness Ozar's proposal for a complete disallowance of Strategic Undergrounding pilots (4T 448-449). He further proposed that the Commission approve up to $1 million to support assessments of lifecycle costs of underground and overhead systems (Ozar, 8T 4016). The PFD was persuaded to recommend a disallowance of pilot funding because "the company has not provided a lifecycle analysis" (PFD, p 218). It should be noted that the need for a lifecycle analysis has never before been communicated to the Company. DTE Electric has followed the Commission's directives to provide the evidence requested in the standard pilot forms, approved in Case No. U-20645. The Company agrees that lifecycle cost analysis is important, but the PFD neglects that this lifecycle work can only be informative when supported by the actual experience that the Company will gain from the Strategic Undergrounding pilots (Pfeuffer, 4T 449). Also, if the Commission would like a lifecycle analysis (as the PFD

suggests is important), then the Commission should approve necessary funding to conduct the analysis (instead of disallowing it as the PFD recommends).

In summary, the Commission has stated that utilities, like DTE Electric, must continue to improve safety and reliability, and we continue to hear customer questions and strong feedback supporting the undergrounding of parts of the distribution grid. Understanding the potential for Strategic Undergrounding is an important part of the Company's plan to achieve its reliability goals. In the pilots, the Company expects to reduce the cost by increasing the volume of work and utilizing the lessons learned from the Appoline pilot and benchmarking, allowing strategic undergrounding to become another important reliability tool. Therefore, the Commission should fully approve the requested funding (Pfeuffer, 4T 450).

iii. Technology & Automation.

Technology & Automation projects and programs are tightly linked to the grid modernization process, and include investments that develop capabilities in observability, analytics and computing, controls, and communications. They meet current grid needs and provide immediate benefits to customers. They also lay the foundation for grid modernization and will support increased adoption of DERs and EVs. Exhibit A-12, Schedule B5.4, page 11 provides details, with additional details at Exhibit A-23, Schedule M6 (Pfeuffer, 4T 277, 347-348, 451). Significant investments include Grid Automation Telecommunications, Distribution Automation, Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO), and Non-Wire Alternatives (NWA).

a. Staff's general disallowance methodologies

The PFD, pp 219-29, begins with general comments on Staff's proposed disallowance methodologies, which are "general objections Staff has to many of the company's projections

without regard to the reasonableness and prudence of the underlying projects" (PFD, p 220). The PFD concludes:

> For these reasons, this PFD concludes that Staff's adjustments are a reasonable means of addressing the evidentiary deficiencies in the company's presentation, and should generally be adopted. PFD, p 229.]

The Company disagrees that Staff's methodologies and resulting adjustments are either "reasonable" or "should generally be adopted" as discussed below. The PFD's comments also, while lengthy, neglect much of the evidence and procedural context. The Company also takes exception to other instances where the PFD follows its characterization of Staff's view of the Company's "t-shirt sizing" methodology and "other" cost component to recommend disallowances, without further analysis (*e.g.*, PFD, pp 275-77, 283).

Staff proposed a generic 20% disallowance across eleven projects (disallowances of $3.623 million in the bridge period; $4.258 million in the projected test year) by comparing them to a forecast of 2020 historical spending that Staff calculated. The Company disagrees for three primary reasons. First, it was improper for the Staff to calculate a forecast for 2020, ignoring the forecast that the Company provided in Case No. U-20561 (Exhibit A-12, Schedule B5.4, page 9, column (d); Exhibit A-41, Schedule FF6). Staff also materially changed the forecast by "adding four months of the forecasted bridge period… and eight months of the projected test year" (Wang, 8T 5223). Staff's use of its own unique calculation method resulted in forecasted amounts different than those that the Company actually presented in Case No. U-20561 (Pfeuffer, 4T 455-457).

Second, Staff performed its analysis based on only a select number of projects in the Technology and Automation category. This category (excluding ESOC and ASOC because they include major building construction) should be viewed as a whole. Excluding approximately half of the projects in this category results in incorrect analysis. The Company is particularly concerned

that Staff did not consider four projects (reflected on the chart at 4T 457) with investments that exceeded their 2020 forecasts (Pfeuffer, 4T 457-458).

Third, Staff's methodology (calculating a percentage of overinvestment/underinvestment per project, and then averaging the percentages to derive an overall percentage) is flawed as discussed above in section IV.C.2.i. If one were to use this type of analysis, however, then it should be correctly performed using all the projects/programs in the Technology and Automation category, excluding ESOC and ASOC. The Company did so, reflecting a "% Projected Cost Actually Spent" of 137% (Pfeuffer, 4T 458-459; Exhibit A-41, Schedule FF8).

Moreover, it is improper for Staff to use its own analysis selectively, applying it to investments when doing so would support proposed disallowances, but then not applying that same analysis to investments when doing so would not support a disallowance. For example, Staff calculated that the ADMS: Network Management System had a "% Projected Cost Actually Spent" of 133.8%, yet instead of applying that 133.8% factor, Staff proposed a 20% disallowance based on Staff's calculated average (Pfeuffer, 4T 460). Applying a disallowance, based on questioning the Company's ability to spend to forecast, to a category where the Company over-invested its forecast, lacks logical support.

In summary, Staff's analysis has numerous flaws, and it applied its analysis inconsistently across the projects analyzed. While the Company asserts that the Commission should not apply a disallowance based upon historical spending in 2020 (or 2021) on technology and automation capital investments, if it chooses to do so, the Commission should at least apply a complete analysis including all like projects in the category.[63] The Company's analysis, applying Staff's

[63] ESOC and ASOC are rightly excluded because, as major building construction projects, they are different in kind from all other technology and automation investments.

methodology to all applicable projects in the category, produces a "% Projected Cost Actually Spent" of 137%. This result highlights the flawed nature of using an average of percentages, as discussed more fully above. When comparing actual dollars spent to actual dollars forecast, the Company was able to invest 92% of its forecast even in the pandemic-impacted year analyzed. Therefore, the ALJ and the Commission should reject the Staff's proposed 20% disallowance (Pfeuffer, 4T 461).

In Staff's Initial Brief, Staff acknowledged that the Company is correct on the first point summarized above, resulting in changes to Staff's recommendations:

> The Company is correct that Staff's calculated forecast amounts for 2020 led to different amounts than the Company's forecast. Staff, therefore, revises its recommended disallowances by using the Company's U-20561 projections and the new level percentage of projected cost that was actually spent. This results in the changes detailed in Table 1 below and a revised projected bridge period recommended capital disallowance of $14,695,000 and projected test year recommended capital disallowances of $9,980,801 across eight projects. [Staff's Initial Brief, pp 85-86. See also, p 87, reflecting that Staff's change is not included in its proposed revenue requirement.]

In her direct testimony, Staff witness Wang stated:

> Of the projects examined, Staff finds an average of 73.3% of projected costs were actually spent. One project spent only 0.36% of the projected spend. Given that an average of 73.3% of projected costs were actually spent in 2020 for the projects analyzed by Staff, Staff finds a downward adjustment of 20% to be reasonable and prudent. [8T 5221.]

This statement contradicts Staff Initial Brief, p 87:

> Though Staff provided the average percent of projected funds that were unspent, this was provided for general understanding. For projects with recommended disallowances, Staff only recommends adjustments based on the percent of projected costs that was actually not spent in 2020 for that particular project.

Staff, as noted in testimony, relied on the analysis to propose disallowances as "reasonable and prudent" to several projects, including: ADMS: Network Management System, Distribution Sensing and Monitoring (including Line Sensors), SCADA/AMI Enhancements, DERMS, DER

Control, Mobile Technology, Substation Design Tool Upgrades, Microwave End of Life, SCADA Remote Access and Configuration Platform, Sensor, Network and Algorithm Development (Solar Deployment) and Substation Cybersecurity; as noted in Staff Exhibit S-7.42 (any line in Exhibit S-7.42 that has a line for 20% disallowance). The PFD agrees that "Staff makes clear that it considers this analysis an estimate of the company's forecast accuracy." (PFD, p 221.)

Additionally, it is unclear why Staff relied on 2020 data when the Company provided 2021 data in discovery and rebuttal for Technology and Automation. This is especially confounding where Staff did include 2021 information provided for Infrastructure Resilience and Hardening and Infrastructure Redesign and Modernization categories. In Staff's Initial Brief on page 86, Staff proposed new disallowances for ADMS: DMS/OMS, Distribution Automation, and Non-Wires Alternatives based solely on 2020 investments. When looking at ADMS: DMS/OMS, Distribution Automation, and Pilot: Non-Wires Alternatives in 2021 it becomes clear that in two of the programs, the Company actually overspent the 2021 forecast for these strategic programs – yet Staff still recommends a disallowance, for underspending in the previous year.

Projects ($000s)	U-20561 2021 Forecast Exhibit A-2 Sch B 5.4	2021 Actuals Exhibit A-41 Schedule FF9	% Projected Cost Actually Spent
ADMS: DMS/OMS	9,900	22,390	226%
Distribution Automation	10,000	111	1.11%
Pilot: Non-Wires Alternatives[64]	2,500	7,698	308%

Again, Staff did not look at every project in this category to determine the Company's overall ability to invest in Technology and Automation, nor did Staff consider all available information including the most recent year's investments. The Company finds it perplexing that

[64] Non-Wires Alternative project list for 2021 includes: O'Shea Energy Storage, Omega Load Relief, Fisher Load Relief, Small Solar and Storage Testbed, and EV Charging Demonstration at ACM.

Staff would consider all available information for Infrastructure Resilience and Hardening and Infrastructure Redesign and Modernization, including reviewing all projects in each category together as a whole and including the most recent year investment profile; but in Technology and Automation, Staff appears to only utilize limited data. (Wang, 8T 5224; Pfeuffer, 4T 457-458).

Staff also proposed disallowances ($6,927,699 in the bridge period; $3,698,781 in the projected test year) that represent a reduction in assumed "Other" costs to 5.17% of total project cost across 22 projects (Wang, 8T 5221-5223). The Company disagrees because it allocates many different overhead costs, consistent with the Uniform System of Accounts (USOA) requirements. The costs for overhead activities are collected into pools and allocated to the capital projects. For example, Facilities overhead costs (related to preventative maintenance, repairs, and improvements to facilities) are allocated to capital projects based on direct labor. Depending on the nature of the capital project, it could have more or less of the specific driver(s), for example, labor, leading to different amounts of overhead allocations (Exhibit A-43, Schedule HH6 provides a list of possible "other" overheads and a description of how they are allocated). Since other overheads can vary depending on the type of project and the direct costs charged to the project, Staff's proposed fixed rate has no sound basis and is unreasonable.

The PFD also errs when it states as additional support for disallowance that the Company "has not explained how it filed its case with flat rates, while now contending that would be unreasonable." (PFD, p 229.) DTE Electric admits that it filed its case with flat rates, however, the Company also explained that doing so was the result of human error (a single cell was accidentally copied into all the cells in the column) and promptly submitted Revised Schedule M6, which provided the actual calculations used in the "other" category, as soon as it realized its error. Thus,

DTE Electric's approach is not at all inconsistent. It was an error when DTE Electric provided flat rates, and it is also an error to apply flat rates as Staff and the PFD propose.

Moreover, the Company provided actual incurred Other Costs information in discovery (Exhibit A-41, Schedule FF9), but Staff indicated that it did not review this discovery response (Exhibit A-41, Schedule FF10). Staff simply made an assumption and did not review other available information to verify (or in this case, disprove) that assumption. Therefore, Staff's proposal to reduce "Other" capital costs by a flat rate of 5.17% should be rejected as unfounded and disproven (Pfeuffer, 4T 61-63; Uzenski, 7T 2785-2786).

Staff's Initial Brief responded:

> The Company's rebuttal position fails to incorporate Staff's actual recommendation. It is not that the Company should only have 5.17% of Other Costs for all projects. "Staff's recommendation is that, in the absence of information regarding how Other Costs are determined and differ for projects, only 5.17% of total project costs should be included in rates at this time for Other Costs." (Wang, 8 TR 5221-22.) Given the information provided by the Company, including in rebuttal, it is unclear how Other Costs are determined for specific projects. [Staff Initial Brief, pp 82-83.]

To the contrary, the Company squarely addressed Staff's recommendation, and demonstrated with evidence that it should be rejected, as discussed above and further explained on the record. It is similarly inaccurate for Staff to suggest that information is lacking where Staff did not review the readily available information (Pfeuffer, 4T 463, further discussed above), and to maintain that "it is unclear how other costs are determined," even after Ms. Uzenski further explained that the Company allocates costs consistent with the USOA, provided examples, and sponsored an exhibit with further detail, as reflected in part above (7T 2785-2786; Exhibit A-43, Schedule HH6).

Staff proposed disallowances ($9,726,000 in the bridge period; $16,060,000 in the projected test year) for capital costs of all Technology and Automation projects (Asset Management Upgrades, Hosting Capacity Enablement, Load Forecasting & Analytics, Other Modernize Grid Management, and Work Management & Scheduling Upgrades projects) based solely on an

indicated concern that the costs were developed using a "high level" methodology that "seems to only consider project size/complexity and duration in estimating the project cost" (Wang, 8T 5188).

The Company disagrees because it is not reasonable or prudent to propose disallowing an entire group of projects based solely on a concern about a cost-estimating model. This is especially true where the Staff does not question the reasonableness or prudence of the projects themselves. The Company also explained in response to Staff discovery (Exhibit A-41, Schedule FF11) that the high-level estimates (referenced in Exhibit A-23, Schedule M6) were developed based on defined scope and timelines and have been vetted thoroughly by the Company's Technology Investment Committee. Staff's further suggestion that there seems to be "[l]ittle consideration for the project scope, goals, and desired outcomes" (Wang, 8T 5188) is similarly inaccurate, and neglects how the Company plans these investments following the Company's multi-year Annual Planning Cycle (APC) process. Therefore, Staff's proposed disallowances should be rejected (Pfeuffer, 4T 464-465; Sharma, 7T 1928, 2129).

Staff maintained its initial position, as stated in witness Wang's direct testimony, but neither addressed the Company's position nor provided additional support for its own. The bottom line remains that: "Staff recommends all projected bridge and test year costs for the five projects with high-level IT costs be disallowed" (Staff Initial Brief, p 57). The Company maintains that its cost-estimation methodology is appropriately detailed and employs the Company's extensive experience in conducting similar projects. Even assuming for argument's sake that there is some merit in Staff's "concern[] about the accuracy of the high-level IT cost estimates" (Staff Initial Brief, p 56), the cost of all five projects is not $0. There is no sound basis for Staff's proposed 100% disallowance, particularly where nobody (including Staff) raises any issue about the projects being reasonable and prudent.

b. Grid Automation Telecommunications.

Robust and secure communications channels are foundational for a modern grid. Many devices on DTE Electric's system, however, are either not connected for remote monitoring and control, or are connected through a communication network that is not fully integrated. The Grid Automation Telecommunications program will address communication gaps, deploy a consistent channel with sufficient and reliable bandwidth to meet the current and growing requirements of a modern electrical system, and allow deployment of the appropriate cybersecurity protocols. In addition, the Company will strategically extend its existing fiber ring to locations that provide the most benefit, providing improved reliability and increased cybersecurity (Pfeuffer, 4T 348-351)

Staff proposed disallowances based on historical spending. The Company objected to Staff's reliance on historic spending. The PFD "finds Staff's reduction reasonably tailors the future projections to the current pace of spending, and should be adopted" (PFD, p 255).

The Company also disagrees that it is appropriate to calculate this disallowance based on historic spending, as explained more fully above, in section IV.C.2.ii.

c. Conservation Voltage Reduction (CVR)/Volt Var Optimization (VVO).

The Company initially began evaluating CVR/VVO as a generation alternative to reduce peak demand and energy consumption as part of the Company's Integrated Resource Plan (IRP) that the Commission approved in Case No. U-20471.[65] The Company continues to implement and evaluate CVR/VVO through pilots both as an offset to peak generation, and additionally because of the potential benefits to the distribution grid. In addition to completing the pilot that the

[65] VVO manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives, which can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters, and/or optimizing power factors. CVR, as one of the VVO options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand, or energy consumption (Pfeuffer, 4T 355).

Commission authorized in the IRP (see February 20, 2020 Order in Case No. U-20471, pp. 74-76), the Company installed or plans to install CVR/VVO on 8 substation transformers and 28 circuits in 2021, 18 substation transformers and 56 circuits in 2022, and 44 substation transformers and 136 circuits in 2023. Based on discussions with industry experts and utilities that have implemented advanced CVR/VVO, savings in energy consumption and peak demand for substations with advanced CVR/VVO in the range of 1.5% to 3.5% may be achievable,[66] but the Company will confirm the actual savings through the projects described in this case (Pfeuffer, 4T 355-359).

Staff proposed a $14,500,000 disallowance in the projected test year for CVR/VVO, reasoning that the projects were in the preliminary stage because the Company expected to select substations for 2023 in the third quarter of 2022 (Evans, 8T 5433). The Company disagrees because it began the project in 2019, and through 2021 had successfully invested $4.6 million (Exhibit A-41, Schedule FF9, page 9, line 11) against a forecast of $4.5 million (Exhibit A-12, Schedule B5.4, page 11, line 11). The Company also maintains a prioritized list of substations for CVR/VVO based on expected energy savings, which currently has 17 substations and 126 circuits identified for 2023 (Pfeuffer, 4T 488). Thus, the project is not in the preliminary stage.

Staff responded that "[w]hile the CVR/VVO project as a whole is not in the preliminary stage, future individual projects that are part of the larger CVR/VVO effort are. Even though the year the projects will be undertaken is known – 2023 – the fact that selection of the circuits and substations that will be upgraded has not yet occurred yet makes the projects preliminary."

The PFD states:

> This PFD finds Staff's testimony persuasive on this point. The Commission has made clear that placeholders with lists of potential projects for the utility to choose from do not justify including ratepayer funding in rate base. [PFD, p 257.]

[66] Details of the results of the initial pilots did fall within this range, as reported in DTE Electric's April 13, 2002, Integrated Resource Plan Annual Report in MPSC Case No. U-20417 (Docket No. 0789).

The Company disagrees because this is an established program as Staff acknowledged, the program has an undisputed track record, and there is no basis to think that the program will simply stop in 2023 as the PFD effectively suggests, given the mature stage of the program. The PFD's proposed 100% disallowance (0% for 2023) is contrary to the record and unreasonable.

Staff also did not indicate any concerns about reasonableness or customer benefits. The sole basis for the Staff's proposed disallowance concerns the timing of identifying specific circuits for 2023. The Company maintains that it is reasonable to identify circuits in the third quarter of the year before execution because identifying circuits from a list of prioritized circuits too far ahead of time would lock the Company into work on circuits that might not be the optimal choice. Therefore, the PFD's proposed disallowance should be rejected (Pfeuffer, 4T 487-489).

d. Automation Configuration and Test Record Database.

Staff has recommended a full disallowance ($2,043,000 in the bridge period; $1,827,000 in the projected test year) for the Automation Configuration and Test Record Database (Test Record) project (Wang, 8T 5193). Staff indicated a concern that the project includes preliminary-stage activities and data conversion costs, and that such items should be expensed (Wang, 8T 5191). Staff's concerns are unwarranted because the project does not include preliminary-stage activities, and data conversion costs will be expensed (Pfeuffer, 4T 452). Therefore, Staff's proposed disallowance should be rejected as unfounded and disproven.

Staff's Initial Brief, p 59, responded that "there is no data supporting the Company's rebuttal claims… Staff cannot assume the Company's rebuttal assertions are correct given the lack of opportunity to confirm these claims and identify how much, if any, of the project costs for data conversion and cleanup costs will actually be expensed."

The PFD states:

> As discussed above, this PFD finds that the company has failed to establish that the project is not in a preliminary stage, or that it identified O&M costs associated with this project that were already capitalized. Staff's adjustment is reasonable and should be adopted. [PFD, p 281.]

The Company incorporates the discussion above and maintains that it appropriately explained that Staff's concern was unfounded, and the Company's testimony alone is sufficient evidence. There was no need to provide additional "data" on a non-issue (plus proving a negative presents logical and practical problems). Staff also did not have to "assume" anything about the Company's rebuttal. If Staff had some lingering doubt (*e.g.*, as indicated, the project *has* preliminary activities because it *had* preliminary activities), then it could have pursued the matter. For example, the AG's Initial Brief references extensive discovery responses that she received regarding the Company's rebuttal testimony (and which further support the Company's positions). It is also too late in the process for Staff to raise new criticisms of the Company's evidentiary presentation in briefing.[67]

The context also bears emphasis. Staff did not contend that the project should not be done, or that the money should not be invested. Instead, Staff's indicated concern was (and is) only that a portion of the expense should be expensed rather than capitalized (affecting, at most, a portion of the return "on" the investment, but not any of the return "of" the investment). Thus, Staff/PFD's

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[67] The Commission previously explained:

> The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position. [January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

proposed 100% disallowance has also always been unreasonable as well as unfounded. For all of these reasons, Staff/PFD's unfounded, unreasonable, and disproven proposal should be rejected.

e. Operational Technology and Error Free Communication (EFC)

Staff proposed a full disallowance ($12,608,000 in the bridge period; $333,000 in the projected test year) for the Operational Technology and Error Free Communication (EFC) project (Wang, 8T 5195) based on the apparent misperception that the project is a minor system upgrade or enhancement that should be expensed (Wang, 8T 5194: "The project appears to be focused on manipulation of the Company's current data from various areas into one single source of data to generate a new type of data report"). To the contrary, the EFC project is a significant project that fundamentally changes the Company's underlying process to communicate with customers, and the project scope goes well beyond simply generating a new type of report and facilitating data retrieval. Unlike IT maintenance work, this project is a major undertaking that requires reworking the interfaces between Company systems (order management, customer information, outbound notification, and outage management) to work in ways that the systems were not originally designed to operate. The project also, and among other things, includes building a new system (Premise Power Status, or PPS) to house the data and business logic driving the flow of information. Therefore, this is a significant project (not simply data manipulation or writing new reports for current systems as Staff suggested) that is appropriately classified as capital, and Staff's proposed disallowances should be rejected as unfounded and disproven (Pfeuffer, 4T 452-454).

Staff's Initial Brief, p 62, responded that costs can be capitalized if they meet three criteria, and: "The Operational Technology and Error Free Communication project meets criteria (2) and (3). However, does it meet criteria (1)? Staff asserts the Company being able to tell customers whether the Company definitely knows whether customers have power or not does not constitute

significant additional functionality." The company responded that Staff's new assertion is unfounded and contrary to the record, as summarized above. Therefore, Staff's proposed disallowance should be rejected.

The PFD disregarded the evidence and arguments that the parties presented on this issue, and instead stated:

> This PFD finds that DTE has not supported its expense projections and concludes that Staff's exclusion of the bridge and test year projections should be adopted. Even putting aside Staff's legitimate concerns about capitalization, as Staff argues, DTE has not explained the $12.6 million cost. Schedule M6, for which some of the deficiencies have been noted above, does not even have minimal cost detail for the $12.6 million bridge period expenditure for this project, with the labor/material/other cost breakdown in M6 limited to the $333,000 projected test year expense. DTE has also made no effort to integrate this "error free" project with its IT "error free" projects, including the $8.1 million expense projection presented in Schedules N1.351 and N1.352, which are duplicative business case documents each covering the April 2021 to October 2021 time period and identified as the support for Schedule B5.7.3, page 1, line 44. Likewise, DTE has not explained how this project relates to all its other OMS expenses, including its difficulty with the OMS component of ADMS as discussed above. [PFD, pp 285-86.]

The Company maintains that it properly supported its requested recovery and responded to Staff's indicated concerns, incorporating the discussion above. The Company also objects to the PFD raising new issues after the record has closed, as discussed in section II above. Contested cases are adversarial proceedings. Many potential issues are eliminated or narrowed through discovery and audit requests. The ALJ should evaluate the issues presented on the record. Here, nobody challenged the cost. Instead, the narrow issue was just whether the cost should be capitalized or expensed (affecting, at most, the return "on" the investment, and not the return "of" the investment). The Company proved that the cost should be capitalized. Therefore, the PFD's recommendation should be rejected.

f. Non-Wires Alternatives (NWA).

NWAs are defined in section 4.3 of the DGP (using the Staff's definition that the Commission adopted in the August 20, 2020 Order in Case No. U-20147, pp 11, 41) as:

> An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

The Commission further advised that it "expects to be presented with 'a robust suite of NWAs that may be evaluated for prudency as possible programs'" (August 20, 2020 Order in Case No. U-20147, pp 43-44, quoting the May 8, 2020 Order in Case No. U-20561, p 112). Accordingly, the Company developed a suite of NWA pilots that focus on using alternative technologies to address circuit or substation overload concerns to help delay or offset traditional grid upgrades (Pfeuffer, 4T 359-360, 468). Ms. Pfeuffer described the Company's methodology for developing NWA pilots (Pfeuffer, 4T 362-364). The suite of NWA pilots proposed in the DGP (along with the technology the Company is testing and objectives) is shown in Table 17 of Ms. Pfeuffer's direct testimony (at 4T 365-366). This includes the first NWA pilot at Hancock substation that began in 2018 and concluded in 2020, and which achieved 57kW of peak reduction (141% of the goal) and provided multiple lessons learned. The pilots the Company is currently pursuing are building blocks, which will form a foundation for future NWA projects (Pfeuffer, 4T 364-369). The Company made expenditures on NWA pilots in 2020 and 2021, with additional commitments and spending in 2022 (Pfeuffer, 4T 469; Exhibit A-12, Schedule B5.4, page 11, lines 12 and 18; Exhibit A-41, Schedule FF9, page 9). The proposed NWA pilots ((Exhibit A-12 Schedule B5.4) include Primary Deconductoring (Exhibit A-12 Schedule B5.4.1), Strategic and Service Undergrounding (Exhibit A-12 Schedule B5.4.2), O'Shea Energy Storage (Exhibit A-12 Schedule B5.4.3), Battery Trailer (Exhibit A-12 Schedule B5.4.4), Omega Load Relief (Exhibit A-12 Schedule B5.4.5), Fisher

Load Relief (Exhibit A-12 Schedule B5.4.6), Port Austin Load Relief ((Exhibit A-12 Schedule B5.4.7), Veridian (Exhibit A-12 Schedule B5.4.8), Small Solar and Storage Test Bed (Exhibit A-12 Schedule B5.4.9), and EV Charging Demonstration at ACM (Exhibit A-12 Schedule B5.4.10). To validate the proposed suite of NWA projects and associated learnings, the Company also engaged EPRI to evaluate the Company's NWAs. EPRI completed its report in June 2022, and states:

> DTEE's approach of incrementally developing NWA capabilities by implementing a series of demonstration projects is appropriate. The existing suite of planned pilot projects will cover several NWA use-cases and leverage multiple DER technologies. The demonstrations will identify key control, protection, cyber security, and other considerations that will shape future standard processes to address NWA effectively and efficiently within planning, operations, and other areas. [Pfeuffer, 4T 484.]

Staff proposed numerous disallowances for NWA expenditures, referring numerous times in discovery responses to a need for "ample evidence" (Exhibit A-41, Schedule FF13).[68] To the contrary, and in addition to the Company's audit and discovery responses, the Company provided: (1) direct testimony (10 pages); (2) Exhibit A-23, Schedule M1 (33 pages); (3) Exhibit A-23, Schedule M6 (36 pages); and (4) Exhibit A-12, Schedule B5.4 (30 pages). Staff also did not indicate any concerns about the Company meeting the pilot documentation requirements described in Case No. U-20645, and the Company provided Exhibit A-12, Schedule B5.4 for that purpose (Pfeuffer, 4T 470).

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[68] "Ample evidence" is not the correct standard. See generally, *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence"). The "preponderance of the evidence" standard is generally defined as follows:

> "***The greater weight of the evidence***, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that has the most convincing force; ***superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other***." *Black's Law Dictionary* 1301 (9th ed 2009). (Emphasis added).

In addition to being unfounded, Staff's "ample evidence" criticism is also inappropriate because Staff was unable to identify what type of evidence it would want the Company to provide, above and beyond what it already provided. Instead, Staff took no position on whether the Company presented a "robust suite of NWAs," and did not define how a "robust suite of NWAs" will be evaluated (Exhibit A-41, Schedule FF2). The Commission should not instruct utilities to develop a "robust suite of NWA" and expect utilities to do so, at significant cost, then deny recovery on the basis of a failure to meet vaguely outlined, inconsistent, or nonexistent requirements over and above those approved by the Commission in U-20645, as the Staff and the PFD suggest.

Staff recommended that 1/3 of the NWA: Omega Load Relief project be disallowed ($2,366,000 in the bridge period; $223,333 in the projected test year) to remove costs which it believes are associated with solar implementation (Wang, 8T 5212-5213). The Company disagrees because it made clear in discovery responses that the project cost does not include any investment in solar capability. See, for example, Exhibit S-7.30 ("The Company will not be pursuing utility scale solar or rooftop solar for NWA Omega load relief project. The project scope and *associated costs does not include solar*") (*Emphasis added*). The proposed 1/3 disallowance is also arbitrary and cannot reflect solar costs because no solar costs exist in the first place (Pfeuffer, 4T 471).[69]

Staff also proposed an additional disallowance ($1,692,396 in the bridge period; $159,750 in the projected test year) by "adjusting the total labor costs so that it is 11% of total material costs,

[69] Ms. Pfeuffer further explained:

> Initial conceptual engineering scope for the Omega project considered adding solar. However, as stated in Staff Witness Wang's Exhibit – S-7.30 response to STDE-15.35 "The Company will not be pursuing utility scale solar or rooftop solar for NWA Omega load relief project. The project scope and associated costs does not include solar." The Company made clear that the project cost does not include any investment in solar capability through discovery responses such as the one quoted above. Additionally, the amount of one third proposed for the disallowance is an arbitrary value that does not, and in fact *cannot*, reflect the cost of solar related to this project since no such costs exist. [4T 471. Emphasis in original.]

more like the NWA: Battery trailer project" (Wang, 8T 5213). The Company disagrees because the projects are not comparable in this regard. The labor cost for the Omega project includes site preparation, which entails cable and conduit installation, and below-grade work. The labor for the mobile battery trailer project does not include site preparation costs. Thus, there are different labor costs for different types of labor. Staff's proposed disallowance should be rejected as unfounded and disproven (Pfeuffer, 4T 472).

The PFD agreed with DTE Electric on the first point (rejecting Staff's proposed 1/3 disallowance for solar), and otherwise agreed with Staff, and presented total disallowance numbers stating:

> [I]t does appear that DTE did not intend this project to include a solar component… Thus, this PFD finds that Staff's adjustment for the scope of the project should be rejected, and Staff's remaining adjustments to this line item should be accepted.
>
> DTE seems to defend the labor allocation in Schedule M6, page 54, although that schedule only has a breakdown of test year project costs of $670,000, with no cost detail for the bridge period projection of $7 million and does not explain the basis for the allocation. DTE's general assertion being site preparation being labor intensive is untimely, given the opportunities—in multiple documents it filed in the project—the company had available to provide meaningful cost detail. Based on Exhibit S-7.2, this PFD finds that the bridge period projections should be reduced by $2.48 million and test year projections should be reduced by $234,553. [PFD, p 262.]

The Company disagrees with the PFD's proposed labor disallowance, incorporating the discussion above. This is especially the case where DTE Electric did in fact provide meaningful cost detail. Exhibit A-41 Sch FF9 provided the 2021 actual cost breakdown by labor, material, and other, of the $5.5M invested in 2021, of which $4.2M was material, which supports the need for more labor in 2022 to install the material purchased in 2021. The Company further disagrees with the PFD's reasoning that "DTE's general assertion about site preparation being labor intensive is untimely." To the contrary, until Staff filed its testimony, the Company had no reason to suspect that anybody

would assert Staff's proposed comparison of this project involving site preparation to a battery trailer project that does not involve site preparation (by rough analogy, like comparing a house to a mobile home). The Company filed a "timely" response in rebuttal, and the Company explanation is beyond credible dispute in light of the indisputable differences between the projects – the Omega project includes site preparation at a real property location (and thus higher labor costs), and the battery trailer project does not include site preparation (and therefore does not include those higher costs). There is no sound basis for the PFD's proposal to disregard the Company's timely and definitive evidence, and in any event, the record firmly supports the Company's recovery. Therefore, the PFD's proposed disallowance should be rejected.

Staff proposed a $2,083,000 disallowance in the projected test year for the NWA: Port Austin Load Relief project, by (1) reasoning that the costs associated with the re-use of the Omega battery for the NWA: Port Austin Load Relief project might not materialize, (2) estimating the solar scope to cost $2 million, and (3) proposing that all costs beyond the $2 million (which Staff attributed to the mobile battery trailer) be disallowed (Wang, 8T 5214). The Company disagrees, first noting that the cost that Staff associated with mobile battery transportation and connection is a small fraction of the costs that Staff attributed to its proposed disallowance. The Port Austin project entails the installation of solar, site preparation including below-grade work, overhead construction, and mobile battery transportation and installation. This scope is necessary regardless of the timing of the mobile battery installation, which is one of the last phases of the project, and only includes battery transportation from Omega and connection to the system (Pfeuffer, 4T 473).

Also, even assuming that there are delays with Omega project completion, this would not eliminate the need for the battery, since the Port Austin project requires both solar and storage to address the loading situation. In the interest of cost efficiency, the Company plans to reuse the

battery first used at Omega, rather than purchase a new battery for this pilot. Thus, there is no sound reason to think that these costs might not materialize as Staff suggested (Pfeuffer, 4T 474-475; Exhibit A-23, Schedule M1, page 409).

The PFD states:

> This PFD finds Staff's analysis persuasive. DTE has not established that its actual spending will align with the amounts forecasted. As stated in the company's DGP, the pilot has certain goals: "test solar and storage to address substation capacity," and "test redeployment of stationary battery from Omega" [citing Exhibit A-23, Schedule M1, p 403]. Part of the pilot goals would be abrogated if DTE were to procure a new battery due to time constraints. DTE has not established that this program is to be in place during the projected test year, so a delay beyond the end of the test year is not compatible with the project as described. [PFD, p 265.]

The Company maintains that it properly supported its cost recovery under the controlling preponderance of the evidence standard. The PFD's newly-asserted[70] speculation[71] that the future might not develop as planned cannot support a decision. The PFD's further reasoning that "DTE has not established that this program is to be in place during the projected test year" also neglects that there is no "used and useful" requirement,[72] and the record evidence that the battery installation

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[70] The Commission previously explained:

> The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position. [January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

[71] An agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986).

[72] *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994) (rejecting argument that the Commission is required to use the "used and useful" test in setting rates).

is one of the last phases of the project, and only includes battery transportation from Omega and connection to the system (Pfeuffer, 4T 473).

Moreover, instead of supporting the Company's efforts to reduce NWA costs by reusing a mobile battery system, Staff has taken the position that it cannot say whether batteries are needed for the Port Austin project (Exhibit A-41, Schedule FF13), in apparent disregard of the evidence. In addition to the discussion above, see Exhibit A-23, Schedule M1, pages 408-10; Exhibit A-23, Schedule M6, pages 59-62; and Exhibit A-12, Schedule B5.4.7, pages 1-4 (Pfeuffer, 4T 475).

Thus, the Company squarely addressed Staff's indicated concern, the PFD's additional musings cannot support a decision, and the proposed disallowance for the Port Austin project should be rejected.

Staff proposed a full disallowance ($1,534,000 in the bridge period; $4,952,000 in the projected test year) for the NWA: Veridian project, reasoning that it lacked internal Company approval (Wang, 8T 5176). The Company explained that it internally approved the project, and it is proceeding (Pfeuffer, 4T 476; Exhibit A-51, p 2). The PFD states:

> As Staff argues, DTE did not present the approval document and a review of Ms. Pfeuffer's testimony references "internal approval for detail engineering being received on May 11, 2022" [citing 4T 476]. This is not an academic issue… [*sua sponte* discussion of project cost and potential funding omitted] As Staff argues, and as MI MAUI and Ann Arbor seem to recognize, it is premature to include funding for this project in rates. [PFD, pp 268-69.]

The Company disagrees and maintains that it properly supported funding for this project. The PFD's primary reason for a proposed disallowance – that the Company did not present the approval document – lacks relevance because it is undisputed that the project is approved. Staff's Initial

Brief, p 48, acknowledged that "the Company internally approved the project."[73] The PFD's suggestion that it was somehow inappropriate for the Company to provide additional information in rebuttal neglects the entire point of rebuttal. Staff raised a concern, and the Company responded to that concern with evidence. The Company has a right to rely on the Commission's standards for rebuttal. [74] The context also bears emphasis – this was internal approval. It is a technical Company internal requirement but does not suggest a substantive issue concerning the project or its cost. It is analogous to adding a signature to a document that Staff and Intervenors have had ample time to review, and do not otherwise contest. The PFD's suggestion that MI MAUI and Ann Arbor opposed the project is also incorrect, as reflected for example by PFD, p 267 (quoting MI MAUI and Ann Arbor's reply brief's recommendation that "the Commission approve the Veridian NWA"). The Company also again objects to the PFD raising new issues after the Company can effectively respond, as discussed in section II. Therefore, the PFD's proposed disallowance should be rejected.

Staff also proposed a 90% disallowance of the labor portion of the costs associated with the NWA: EV Charging Demonstration at ACM for the sole reason that it is a "high-level estimate" (Staff Initial Brief, pp 76-77). The PFD agreed, without elaboration (PFD, p 272). The Company disagrees, and the proposed disallowance should be rejected, for the same reasons the Company

[73] "The state, as well as an individual, may be estopped by its acts, conduct, silence and acquiescence." *Wiersma v Michigan Bell Telephone Co*, 156 Mich App 176, 185; 401 NW2d 265 (1987). *See also, Michigan Gas Utilities v Public Service Comm*, 200 Mich App 576, 584-85; 505 NW2d 27 (1993) (rejecting agency's attempt to disavow its prior decision, explaining that if an estoppel existed, it was against the agency); *Entergy Gulf States, Inc v Louisiana Public Service Comm*, 730 So2d 890, 901 (1999) (reversing agency's decision as "untenable" and finding all its reasons to be "arbitrary or capricious or unsupported by the record").

[74] See for example, *In re Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002) (reversing the MPSC because it misinterpreted and misapplied its own rule in order to reach its desired result); *DeBeaussaert v Shelby Twp*, 122 Mich App 128, 130; 333 NW2d 22 (1982) ("Once an agency has issued rules and regulations to govern its activity, it may not violate them"); *Bohannen v Sheridan-Cadillac Hotel, Inc*, 3 Mich App 81, 82; 141 NW2d 722 (1966) ("When an administrative agency promulgates a rule for the benefit of litigants and then deprives a litigant of this right, it is a violation of both the 1908 and 1963 Michigan Constitutions").

disagrees with other PFD/Staff disallowances based solely on the "high-level estimate" issues discussed in these Exceptions.

g. Technology programs & NWA.

Staff asserted that "[g]iven that the Technology Programs & NWA programs subparts are all either completed with no ongoing costs or are now separate projects with capital costs included elsewhere in the U-20836 case, Staff recommends full disallowance of the projected bridge period capital costs for this project totaling $2,000" (Wang, 8T 5185). The Company disagrees because these are past investments that were made in 2021. Staff incorrectly attributes these past (2021) investments to the future (2022 bridge period), so Staff's proposed disallowance should be rejected (Pfeuffer, 4T 466).

Staff's Initial Brief, pp 53-54, responded that (1) the bridge period includes 2021, and (2) the programs and subprojects are either completed or located elsewhere. Staff's response misses the Company's point and neglects the temporal context: (1) 2021 is the past, and (2) Staff's reasoning concerns the present and future. There is a disconnect in Staff's reasoning that the Company fully explained, so Staff's proposed disallowance should be rejected. The PFD states:

> While this is not a material adjustment, this PFD defers to Staff's recommendation and finds that the $2,000 adjustment should be made. DTE chose the 2020 historical year and did not present final numbers for 2021 in its filing. Its discovery response to Staff was arguably ambiguous, but it is the company, not Staff, that has the obligation to support details of its expense projections. It is also troubling that DTE would transfer additional spending for projects in this group to other line items, without providing a reconciliation, making it more difficult to evaluate this line item and the other line items that now include expenditures for this project. [PFD, pp 273-74.]

The Company disagrees, incorporating its discussion above. Furthermore, the response was not ambiguous – the Company stated that it made the investment, when it made the investment, and

provided the amount of the investment. The PFD's reasoning is disconnected from the evidence, which instead supports the Company's requested recovery.

In summary, the Company developed a "robust suite of NWAs" in response to the Commission's stated expectation. The Company also provided voluminous evidence supporting its pilots and the expenditures that it made on them. The PFD/Staff's proposed disallowances are unfounded, and at times contrary to Staff's own evidence. Therefore, the proposed NWA disallowances should be rejected (Pfeuffer, 4T 484).

h. Advanced Distribution Management System (ADMS)

The Advanced Distribution Management System (ADMS) is the technology platform that will substantially improve DTE Electric's ability to manage electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages more quickly. DTE Electric is replacing several systems that are at end of life with the following components that comprise ADMS: Generation Management System (GMS); Energy Management System (EMS); Outage Management System (OMS); and Distribution Management System (DMS). The Company is also adding the Network Management System (NMS) as part of ADMS. Customer benefits include reduced outage durations and better communications on the status of their electric service and expected restoration times (Elliott Andahazy, 7T 1490-1495. See section 12.1 of the DGP for details regarding benefits of the ADMS in different scenarios). The Commission previously found "this capital expense amount to be reasonable in light of the significant improvements in reliability, integration with distribution resources, and substation outage risk that are offered by ADMS, and the fact that it is becoming commonplace in the industry" (May 2, 2019 Order in Case No. 20162, p 29).

i. Outage Management System (OMS) / Distribution Management System (DMS)

Ms. Elliott Andahazy further discussed the progress and strategy for deploying the OMS and DMS components of the ADMS project, due to delays in the delivery of the Compass mobile tool, driven largely by the complexity of the technology and restrictions imposed during the COVID pandemic. The Company modified the project management process to ensure that the delivery dates of the OMS and DMS components will not be further delayed and will leverage another field work force (field force) management solution called ClickSoft, which is already included in the Company's strategic plan for overhead and underground field resources. Customers will benefit from shorter restoration times and improved response to trouble in the field. Despite the delays, it is still important for DTE Electric to pursue the OMS and DMS components of ADMS for SAIDI improvements, replacement of end-of-life technology, seamless integration of components, automating manual processes, and improved situational awareness. The Global Prioritization Model (GPM) also continues to rank ADMS as the top project due to its importance to the Company's plan to improve reliability for customers and modernize the grid to respond to increasing weather volatility, new technologies, and electrification (Elliott Andahazy, 7T 1502-1513).

The PFD states:

> This PFD finds that DTE has not justified the additional costs it now projects for this project. DTE seems to acknowledge it is standard industry practice to hire a System Administrator when implementing ADMS, yet DTE did not retain one until 2020, well into the project and well after the first version of OMS was supposed to be approved [citing 7T 1498.] Nor has DTE explained whether it took any contractual steps or has identified any contractual remedies associated with the delay. For these reasons, it has failed to show that it reasonably and prudently implemented this project, and the cost overruns should not be funded by ratepayers, This PFD recognizes that DTE has not completed its efforts to implement OMS; it should be allowed to seek recovery of the total project costs following implementation, with a detailed presentation to show how it protected ratepayer interests throughout the project. [PFD, p 238.]

The Company agrees only that it should be allowed to seek recovery of total project costs (including any cost recovery not provided in this case) in subsequent proceedings. The Company disagrees with the PFD's recommendation that the Commission should disallow all cost overruns in this case, further noting that the PFD's rationale is based on new criticisms (unfounded speculation that hiring a System Integrator earlier[75] would have changed results that were driven by COVID and other issues, and criticizing the Company for not explaining something that was not an issue) rather than a discussion of the evidence and arguments that were presented, and which are discussed below for a proper understanding of this area.

In addition to the overview presented above, the Company further supported its cost recovery in response to AG witness Coppola's proposal for a complete ($40,879,000) disallowance for the DMS/OMS project ($28,449,000 for the ten months ending October 31, 2022, and $12,430,000 for the test year) based on his assertion that the Company made a "premature decision to proceed with a suite of products that were not fully developed and proven" (Coppola, 8T 4769). Mr. Coppola similarly recounted his testimony from Case No. U-20162 criticizing new technology (8T 4768), but the ALJ in that case noted that the ADMS projects will help address systems "that have reached end-of-life" (PFD, p 83), and the Commission adopted the ALJ's findings, further noting: "Simply because technology is new does not mean that it should be ignored, or that it will not provide a benefit to ratepayers" (May 2, 2019 Order in Case No. U-20162, p 28).

[75] DTE Electric hired the System Integrator in early 2020 (Elliot Andahazy, 7T 1502-1503) and there is no evidence in the record that would support a conclusion that hiring a system integrator earlier (a very expensive proposition) would have avoided delays in vendor development of the software package. It is the system integrator's job to integrate a software package into an existing system, which cannot be done without first having the software package. *Id.* In addition, hiring a system integrator in 2019 or even earlier than spring of 2020 would not have lessened the impacts of COVID, which did not begin until mid-March 2020. Executive Order 2020-21, March 23, 2020 "Stay Home, Stay Safe."

The Company further explained that the DMS/OMS provides benefits to customers including SAIDI improvements (outlined above), and the AG did not provide any evidence showing any lack of customer value. The AG also ignored that ADMS (of which DMS/OMS is an essential component) is the essential technology to support the modernized grid, and that the ADMS investment was required to replace existing systems that were reaching end-of-life (Elliott Andahazy, 7T 1494-1495, 1540-1542).

Moreover, the AG's $40.9 million proposed disallowance is substantially greater than the total increase that the Company requests (the Company's original $29.2 million request has been corrected to $27.0 million as described in discovery responses; see Exhibit A-46, Schedule KK2). Ms. Elliott Andahazy further explained that the total project cost increased by (1) $3.7 million of planned investment that was disclosed but not included in Case No. U-20561 due to the years involved in that case; (2) $6.6 million for an expanded ADMS Reporting project (as corrected in STDE-4.28, Exhibit A-46, Schedule KK2; the original ADMS project assumed a nominal investment in reports associated with ADMS data, but the Company then learned about the rapidly-evolving benefits of Cloud computing and made the strategic decision to move its IT investments in that direction for all future development where the Cloud approach is consistent with safety or regulatory standards); (3) $6.9 million included for the emergent trouble portion of the ClickSoft project already planned in the Company's strategic investment, but which is merely being pulled forward to correspond to the OMS cutover date; and (4) $9.8 million for project delays due to COVID and the delayed delivery of the Compass mobile tool (as corrected in STDE-4.25, Exhibit A-46, Schedule KK2). The AG did not even claim that items 1-3 are unreasonable or imprudent, and item 4 is a combination of the impacts of the delayed Compass mobile tool and the COVID pandemic. It appears that the AG seeks to retroactively disallow capital that the Commission

approved previously because witness Coppola maintains his overall disagreement with the investment because it encompasses new technologies, not because of project delays and project investment increases (Elliott Andahazy, 7T 1503-1505, 1513-1517, 1541; Exhibit A-12, Schedule B5.4, page 11, line 2).

In summary, when the Company selected OSI Inc., that company offered a fully integrated platform of ADMS components, with multiple components seen as industry leading. When OSI had challenges meeting the timely delivery of the new Compass mobile tool with the required functionality, the Company was able to pull ahead the emergent trouble portion of the ClickSoft project that was slated to come later as an alternative to ensure no further delays would affect field personnel's use of this system. The Commission has already reviewed and approved project investments, and there is no new evidence claiming that the project is not providing the value that the Company identified. Therefore, the AG's proposed disallowance should be rejected (Elliott Andahazy, 7T 1497-1498, 1542-1543).

Staff's Initial Brief increased witness Wang's proposed disallowance for ADMS: DMS/OMS from the blanket 20%,[76] to the percent underspent on this project in 2020. However, as explained more fully above, this is inappropriate where in 2021 the Company overspent on ADMS: DMS/OMS, which is shown in Exhibit A-41 Schedule FF9:

[76] Staff witness Wang proposed two disallowances associated with the ADMS: DMS/OMS project - one for "other cost" adjustment, and one for "historic spend adjustment." The Company incorporates its discussion of Company witness Pfeuffer's Rebuttal Issue 12 regarding the "other cost" adjustment" (4T 461-463; 7T 2785-2786) and witness Pfeuffer's Rebuttal Issue 11 regarding the "historic spend adjustment" estimate (4T 454-461). Witness Elliott Andahazy further explained that regarding the "historic spend adjustment," Staff based its disallowance on an underestimate from 2020 (Exhibit S-7.42) but neglected to address the cause of the delays in 2020 (discussed at Elliott Andahazy, 7T 1503-1505) and assumed that these delays would continue into 2022 and 2023, without providing any supporting evidence.

Projects ($000s)	U-20561 2021 Forecast Exhibit A-12 Sch B5.4, p 9, ln 4.	2021 Actuals Exhibit A-41 Schedule FF9	% Projected Cost Actually Spent
ADMS: DMS/OMS	9,900	22,390	226%

Ms. Elliott Andahazy's direct testimony also discussed mitigation steps that the Company put in place to prevent further delays (examples include modifying the implementation sequence of remaining components, pulling up the implementation of the emergent trouble portion of the ClickSoft project for the OMS rollout, and modifying the project management processes), but Staff did not address these measures (Elliott Andahazy, 7T 1506-1507, 1512, 1543).

As discussed above in response to the AG, the Commission previously found the investment in ADMS: DMS/OMS to be beneficial to customers. The remaining investment is needed to complete the project and ensure its full functionality for the benefit of customers. Staff offered no argument against the importance of the investment and did not mention either customer benefits or the replacement of an end-of-life system. Staff's proposed disallowances ($8.756 million in the bridge period, and $2.161 million in the projected test year) are based on the arbitrary use of one year of historical capital investment, and the arbitrary selection of "other costs" percent of total project capital. Therefore, Staff's proposed disallowance should be rejected (Pfeuffer, 4T 454-463; Elliott Andahazy, 7T 1544-1545; Uzenski, 7T 2785-2786).

Returning to the PFD, in light of this evidence, DTE has fully justified its requested cost recovery and there is no sound basis for any disallowance. Therefore, the Company's requested cost recovery should be approved.

j. Network Management System (NMS)

Company witness Elliott Andahazy further explained that the Company successfully completed the implementation of the GMS in 2018, followed by the EMS in 2019, and NMS in

2020. As part of the recent grid modernization efforts, however, the Company determined that it needed additional investments in the Network Model data quality to support the advanced planning tools and process for scenario planning. Therefore, the Company seeks an additional $6.3 million related to NMS in 2021-2023 to support further development of high-quality data in the Network Model that it did not include in the original scope of the NMS project. Customers will benefit through downstream planning and operational processes that leverage the as-built network model. For example, the Company has been able to respond even faster to requests for connecting customers' distributed generation and distributed storage through the Company's planning processes (Elliott Andahazy, 7T 1498-1502; Exhibit A-12, Schedule B5.4, page 11, line 3).

AG witness Coppola asserted that "it is not clear what the additional data requirements are and what incremental value will be generated by the additional functionality" (8T 4765), and proposed disallowances of $2,334,000 for the ten months ending October 31, 2022, and $2,883,000 for the projected test year (8T 4766-4767). The Company disagrees because Ms. Elliott Andahazy's direct testimony (summarized above) provided detailed information regarding the successful implementation of the initial ADMS, NMS project investment, how the Company determined the need for additional investments in the network model, and the actual work it will complete for the requested $6.3 million. The Company also provided further details by responding to 16 discovery questions (as seen in Exhibit A-46, Schedule KK1, particularly response AGDE-7.205a). Ms. Elliott Andahazy further explained on rebuttal why it is reasonable that the ADMS data requirements would evolve after completing the initial ADMS and NMS project scope. In summary, the additional investment includes technology to better align field conditions and maps to the digital representation of the grid, integration between asset systems, new data models to support planning and operations topography and characteristics, and advanced analytics to leverage sensor data to

continuously improve the Network Model. Therefore, the AG's proposed disallowance should be rejected. (Elliott Andahazy, 7T 1498-1502, 1536-1537).[77]

The PFD states:

> This PFD finds the Attorney General's analysis persuasive to establish that DTE has failed to justify the additional spending for this project relative to its initial scope. Mr. Coppola has made clear that he reviewed the company's discovery responses regarding the project [citing 8T 4765-66.] Consistent with the discussion of DTE's IT projections in subsection F below, DTE's discussions of its project benefits do not readily allow for evaluation of the benefits of this project relative to the many other DTE projects that similarly promote savings, and the company's decision not to provide any quantification of the project benefits also frustrates review. [PFD, pp 241-42.]

The Company disagrees, incorporating the discussion above, which summarizes the evidence fully supporting cost recovery. The PFD's rationale also lacks merit and relevance. Whether the AG's witness reviews discovery requests and whether other projects have more or less benefits are not a standards for recovery (particularly where, as here, the PFD acknowledges that all of the projects promote savings).

3. System Operating Center (SOC) Modernization: The Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)

The System Operating Center (SOC) Modernization project is aimed at replacing the Company's outdated primary SOC and outdated backup SOC by constructing two facilities (the Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)) designed using current industry security, resiliency, and operability standards. The SOC

[77] For completeness, the Company also notes that Staff witness Wang proposed two disallowances associated with the ADMS: NMS project - one for "other cost" adjustment, and one for "high-level" estimate. The Company incorporates its discussions above regarding Staff's "Other Cost" adjustment and "high-level" estimate disallowance proposals. Regarding the "high-level" estimate, witness Elliott Andahazy further explained that Staff's basis for the 20% disallowance included a review of historic underinvestment in technology projects. The ADMS: NMS project, and the associated costs included in this rate case, are not based on a "high-level" cost estimate, so the project should not be subject to the proposed across-the-board 20% disallowance. For all these reasons, Staff's proposed disallowances are unfounded and unreasonable, so they should be rejected (Elliott Andahazy, 7T 1537-1538).

Modernization project is needed to address the outdated facilities and technology, space limitations, and limited visibility of telecommunication infrastructure performance (Elliott Andahazy, 7T 1518-1520). Expenditures for the project were included in the Company's last two rate cases, and the Commission previously "stresse[d] the need for and importance of this modernization project for system operations from a reliability and resiliency standpoint" (May 2, 2019 Order in Case No. U-20162, p 30).

Case Nos. U-20162 and U-20561 projected a total investment for ESOC and ASOC of $110.7 million from 2017-2021, and $106.9 million was previously approved for inclusion in rate base (due to the difference between test years and calendar years). The new total cost for the ESOC is $98.5 million (historic 2017-2020 plus projected 2021 and 2022 investments), which is an increase of $20.5 million over the original projected investment in ESOC. The increased costs are due to construction delays caused by COVID, plus an increase in square footage (from 42,000 to 63,900 to allow for the co-location of critical support personnel, in addition to system operators and dispatchers in the original plan, to increase efficiency and collaboration), additional testing and permitting, and a new IT datacenter with additional integration efforts (to achieve the desired level of disaster tolerance needed to ensure that the new facility would remain operational during significant events).

The new total cost for the ASOC is $34.5 million, which is $1.5 million more than the original plan (the planned location shifted from a site near the existing backup SOC, to the same location as the new proposed Waterford service center, so the Company will be able to leverage synergies in construction and reduce overall costs closer to alignment with the initial estimates provided in Case No. U-20561). The Company requests to include the incremental $22.1 million in rate base (Elliott Andahazy, 7T 1520-1530; Exhibit A-12, Schedule B5.4, page 11, lines 4 and 5).

The PFD instead recommended that funding for the ASOC is premature, and the Staff's and AG's proposed disallowances for the ESOC should be adopted, explaining in part:

> First, this PFD finds that it is premature to include any funding for the ASOC. As Staff argues, DTE is still in the preliminary design stage, it does not anticipate groundbreaking util 2023, and has a history of not executing this project as planned. If DTE has concrete plans and a firm construction schedule by the time its next case rolls around, it will have the opportunity to seek cost recovery at that point.
>
> …
>
> This PFD finds that DTE has not established a basis for the cost overruns for this project relative to the costs included in Case No. U-20561, and concludes that the Commission should adopt the disallowance for the ESOC recommended by Staff and the Attorney General. [PFD, pp 251-54.]

The Company agrees only that to the extent full funding is not provided in this case, it can seek recovery in subsequent proceedings. The Company otherwise maintains that both facilities are justified and should be fully funded in this case, incorporating the discussion above. The Company further notes that the PFD's recommendation that the "Commission should adopt the disallowance for the ESOC recommended by Staff and the Attorney General." The Company discusses both below and maintains that neither is appropriate.

Further regarding the ASOC, due to the critical nature of the ESOC in operating the electric infrastructure, a backup facility is required in the event the primary facility is inoperable, and the ASOC's location (approximately 25 miles from the new ESOC[78]) will allow the Company to safely operate the grid in the case of a major adverse event at the ESOC (Elliott Andahazy, 7T 1527-1530). Customers will benefit in numerous ways from the SOC Modernization project, as Ms. Elliott Andahazy testified:

[78] The PFD claims that DTE Electric has not been "candid" in providing its reasons for the delay because Mr. Bruzzano previously testified that the originally planned site for the ASOC was also approximately 25 miles away (PFD, p 252). This is pure speculation. Just because both the old location (Western Wayne) and the new location (Waterford) of the ASOC are both roughly 25 miles away from the ESOC does not mean that DTE Electric is not being candid. Rather it says more about the size of the Detroit metropolitan area and the required amount of physical distance required for NERC compliance.

> Customers will benefit from the improved communications paths between resources that will be co-located in the new facilities, which will facilitate quicker and improved coordination to create and implement restoration strategies more efficiently. Plus, customers will benefit from reduced risk in disruption in operations during outage events, and faster restoration times regardless of the facility from which the System Operations organization is forced to operate. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the co-location of the system operators, dispatchers, and support personnel. In addition, ESOC will be more resilient and hardened to withstand adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the event of a major catastrophe. [7T 1530.]

Staff "recommends a capital disallowance of $14,369,000 in the projected bridge period and $62,000 in the projected test year for the SOC: ESOC project" (Wang, 8T 5207). The Company disagrees with what is essentially a total disallowance, and further notes that these are largely historical expenditures because ESOC construction is almost complete, and the building is currently being used for day-to-day operations (Elliott Andahazy, 7T 1548). Staff's reasoning is also flawed, as explained in part above in response to the AG.

More specifically, Staff presented four arguments in support of its proposed disallowance. First, Staff asserted that the Company "failed to indicate that further co-location of additional personnel at the ESOC is well-established industry best practices" (Wang, 8T 5200). To the contrary, the Company supported the co-location of personnel as an industry best practice and otherwise, as discussed above in response to the AG (Elliott Andahazy, 7T 1545-1546, 1548 "*The continued learnings from benchmarking showed that other utilities continue to keep these personnel close to the control room as a best practice*.").

Second, Staff compared the ESOC to the average square footage of other control room facilities (Wang, 8T 5202). Staff's table (originally submitted by the Company in STDE-4.36, Exhibit A-46, Schedule KK3) is a subset of all utilities benchmarked by the Company as set out in Case No. U-20162. The table provides no context on the size of the company, how many customers

each serve, the size/type of system (which determines the NERC operational entity), or volume of day-to-day emergent trouble. The table also lists three control room facilities for PG&E, while excluding the required back-up facility. DTE Electric only has one control room facility for all electric distribution operations while providing back-up for the local balancing authority, which is called the Merchant Operations Center (MOC). Therefore, it was not reasonable for Staff to rely on the average size of these control rooms in comparison to the ESOC (Elliott Andahazy, 7T 1548-1549).

Third, Staff asserted that it "cannot exclude the possibility that the addition of the mezzanine level to the ESOC was motivated by non-functional considerations, such as aesthetics" (Wang, 8T 5202). Staff's assertion is unsupported speculation that cannot support a decision.[79] In contrast, the Company provided record evidence showing that the redesign was driven by operational efficiencies as discussed above (Elliott Andahazy, 7T 1549).

Fourth, Staff suggested that the current hybrid working model for the support personnel indicates that the Company no longer needs the additional space. Staff relied on a discovery response indicating that on a day-to-day basis, up to 50% of personnel work on-site (Wang, 8T 5203), but like the AG, Staff disregarded the final sentence in the response – "At any time, the full team can be required to work at the site as the team mission requires" (discovery response STDE-4.38, Exhibit A-46, Schedule KK3). The Company incorporates its additional response to the AG, explaining why the current hybrid work structure does not negate the need for the additional space (Elliott Andahazy, 7T 1546-1547, 1548-1550).

[79] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by in evidence that a reasonable person would consider adequate).

Staff also "recommends that 2/3 of the SOC: ASOC project capital costs be disallowed from inclusion in rates, given the uncertainty of these costs materializing. This results in a capital disallowance of $5,930,000 in the projected bridge period and $14,424,000 in the projected test year" (Wang, 8T 5208). The Company disagrees, noting that Staff did not offer any data or analytics to support its proposed 2/3 disallowance, but instead simply indicated belief that the investment might not happen (Elliott Andahazy, 7T 1550). Such speculation cannot support a decision, as discussed above. Moreover, Staff's same witness contradicted her own indicated belief by testifying that "with the ESOC nearing completion, Staff believes the Company will turn its attention to construction and occupancy of the ASOC next" (Wang, 8T 5208). The ALJ agreed with DTE that there was no support for the Staff's proposed 2/3 disallowance, but still recommended disallowance for ASOC.[80]

AG witness Coppola also proposed a disallowance for the ESOC, asserting that "the Company has not adequately justified the expanded scope of the project or made a compelling and convincing case that the additional capital expenditures for the ESOC were justified" (8T 4773). To the contrary, details regarding the expanded scope of the project were provided in Company witness Elliott Andahazy's direct testimony (7T 1524-1527) and discovery responses as indicated in Exhibit A-46, Schedule KK3. In summary, the additional personnel at issue (Operational Engineering and SCADA Realtime Support workgroups) were previously located in the same building as the control room operators, so that these employees are close to the control room when required to support real-time operations. Benchmarking further shows that other utilities continue

[80] The PFD narrative is inconsistent with Appendix E.

to keep these personnel close to the control room as a best practice (Elliott Andahazy, 7T 1545-1546). [81]

Mr. Coppola further suggested that "due to the work flexibility offered to employees due to Covid-19, approximately half of the operational engineers and SCADA support staff are not making regular use of the space in the ESOC built for them and will work remotely. This development partially negates the need for the square footage expansion of the building" (Coppola, 8T 4773). This conclusion is faulty because it ignores that at "any time, the full team can be required to work at the site as the team mission requires," as the Company explained in a discovery response to STDE-4.38 (Exhibit A-46, Schedule KK3). Examples of the Company requiring all of these employees to report to the ESOC to work, even during the pandemic, include system upgrades/maintenance, peak load days in the summer, and major storm events, which can occur throughout the year. Without the additional space, the building would not be able to accommodate times when all employees need to be there. It is also unclear whether the hybrid work model will continue post-pandemic. The building will be used for decades, so it would not have been prudent to design it based on day-to-day pandemic statistics, and then have to add to it in the future when more employees return to regularly working on-site (Elliott Andahazy, 7T 1546-1547).

The PFD indicates acceptance of disallowances for ESOC recommended by both the Staff and the AG, despite these parties recommending different amounts. While it appears that the PFD agrees with the rationale of both Staff and the AG, the PFD adopts the $14.4 million disallowance amount suggested by the Staff for the bridge and test period.[82] (PDF, Appendix E, line 46.)

[81] The AG's suggestions that the Company must satisfy a "compelling and convincing" burden of proof or some nebulous "adequately justified" standard are also contrary to applicable law including the "preponderance of the evidence" standard, as above discussed in section II.

[82] The AG had proposed a disallowance of approximately $20.5 million for ESOC.

For the above reasons, the PFD's recommendation to adopt the Staff and AG's proposed disallowance for ESOC should be rejected as unfounded and unreasonable, and the Company's SOC: ESOC and ASOC requests should be fully approved.

4. Advanced Metering Infrastructure (AMI)

Advanced Metering Infrastructure (AMI) meters (also known as smart meters) increase reliability, reduce outage time, and provide other benefits as compared to obsolete electromechanical (analog) meters (See generally, DTE Electric's Initial Brief, pp 104-11). Mr. Smith supported capital investments for AMI technology enhancements including capital spending required for Cell Relay (CR)[83] replacements due to public cellular wireless carriers phasing out of 3G cellular by year-end 2021. The upgrade for residential and small commercial customers was completed in 2020, with DTE Electric installing nearly 2,700 4G relays to cover areas previously supported through 3G technologies. With respect to large commercial and industrial (C&I) customers, as of August 1, 2021, DTE Electric has deployed all sites planned to utilize Power Quality (PQ) meters, and 2,750 of 5,000 meters required to address the remaining C&I sites (Smith, 7T 1905-1906; Exhibit A-12, Schedule B5.4, page 11, lines 30 and 31).

Staff initially recommended disallowance of $0.6 million for meters seasonally affected by vegetation, but "[u]pon the receipt of the additional information, Staff retracts this recommendation… The ALJ and Commission should approve the Company's $0.6 million request…") (Staff Initial Brief, pp 88-89). There is no further dispute on this issue.

Turning to the industrial 3G to 4G program, most of the cost is to purchase 6,000 meters with 4G capability. Approximately 950 of those meters are advanced power quality (PQ) meters

[83] A CR is an "aggregator" or "gateway" within a service area that allows the AMI meter to communicate with the Company's backend systems to capture meter-read data (Smith, 7T 1905).

for the largest C&I customers. The Company spent $10.9 million through December 31, 2020, and projects another $2.2 million through the end of the test year (Smith, 7T 1909; Exhibit A-12, Schedule B5.4, page 11). The PQ meters are a risk-avoidance investment that allows the Company to detect and act on electrical disturbances more precisely, thereby reducing negative impacts to equipment and operations. DTE Electric seeks approval of the $3.9 million of PQ upgrade costs above the $9.2 million approved in Case No. U-20561 based on the risk associated with undetected systemic power quality issues, and because event-based disturbances can impact very costly customer equipment and plant operations run time, as well as Company-owned equipment. The PQ meters were a reasonable and prudent investment made at an appropriate time for the Company's highest-load customers, and the $3.9 million should be approved. If the Commission disagrees, however, then it should at least approve $698,000 to cover the costs of replacing 3G meters with non-PQ 4G meters (Smith, 7T 1911-1912, 1916-1918).

"Staff agrees with the Company on the allowance of $0.7 million in costs to cover the replacement of existing 3G meters with non-PQ 4G meters" (Staff Initial Brief, p 90, further explaining that Staff was unclear in which period this expenditure is included, so Staff reduced its proposed disallowance in the bridge period). The PFD states:

> For the reasons explained in Staff's brief, this PFD finds that Staff's revised recommendation is reasonable and should be adopted. [PFD, p 281.]

The Company appreciates Staff's movement on these issues, but respectfully maintains that the full cost ($3.9 million) of the PQ meters should be allowed. Staff suggested (and the PFD apparently agreed) that "[u]ntil the benefits of the advanced power quality meter can be qualified or proven with actual evidence, the Company's request should be denied." By analogy, that is like not building a bridge because there is no actual count of people driving over the bridge. The Company is in an evidentiary dilemma – it cannot provide "actual evidence" of customer benefits

from the investment until it makes the investment that will provide the "actual evidence" of those benefits by capturing occurrences and responses to power disturbances. There is, however, reasonable evidence of numerous benefits based on industry use of PQ meters by other utilities, as reflected by generally available publications (Smith, 7T 1909-1911).

The investment in PQ meters for the Company's highest-load customers is designed to reduce impact and/or damage to grid assets or customer equipment if disturbances occur. These customers have loads of 1 megawatt or greater and would have the largest potential for equipment damage in these scenarios. The PQ meters must be in service before the electrical disturbances occur so that the disturbances are detected immediately, and relevant data is available to inform personnel and/or customers if immediate, mitigating action is needed (Smith, 7T 1917).

In addition, Staff misunderstood the Company's request for recovery of historical expense, incorrectly recommending disallowance in the bridge period and test year (Staff Initial Brief, p. 90). The Company is requesting recovery of $3.9 million of investments made to deploy power quality metering within its service territory above the $9.2 million approved in U-20561 (Smith, 7T 1911-1912). Therefore, the PQ meters were an appropriate investment made at an appropriate time for the Company's highest-load customers, and the $3.9 million investment should be approved.

5. Community Lighting

Mr. Bellini supported DTE Electric's Community Lighting capital expenditures for 2020 through the projected period ending October 31, 2023 (7T 1710). Capital spending for Community Lighting (detailed on Exhibit A-12, Schedule B5.5) was $15.2 million in 2020, and was expected to be approximately $15.7 million for 2021, $13.9 million for the 10 months ending October 31, 2022, and $16.7 million for the 12 months ending October 31, 2023 (Bellini, 7T 1721).

Staff proposed total capital disallowances of $1,848,079 in the bridge period, and $1,154,236 in the projected test year (Wang, 8T 5172-5173). The Company disagrees because Staff's disallowances are subjective and inconsistently applied. Staff determined its disallowance factor of 5.87% by only analyzing the Company's 2021 actual Capital expenditures as compared to 2021 projected Capital expenditures (Wang, Confidential Ex S-7.2). However, Staff Witness Wang seemingly acknowledges that the Company's "Actual Historical vs Projected Historical" Capital spend was higher for the 12 months ended 12/31/20 (Wang, Confidential Ex S-7.1). Though part of Staff's analysis, there was no consideration given to the Company's 2020 actual Capital overspend vs 2020 projected Capital spend when calculating the proposed disallowance percentage, and instead was solely based on the 2021 Capital underspend vs 2021 projected spend. This percentage was applied indiscriminately and inappropriately. Staff did not account for unique factors that negatively impacted the Company's 2021 Capital expenditures including (1) the slowdown in new business installations due to volatility attributable to COVID, including disruptions in crew availability in 2021, and (2) a high-impact storm season that resulted in crews that would otherwise have been assigned to new business installs, instead being re-assigned to storm restoration work (Bellini, 7T, 1774-1775). Staff also applied this percentage regardless of merit. For example, Staff applies its calculated disallowance percentage to the Company's proposed cable replacement program to replace failing in-service cable, which is new and not reflected in historical spend, (Bellini, 7T 1774-1775), with forecasted Capital expenditures of $1 million per year.

The Company's Capital expenditures should be fully approved. The PFD states:

> At the outset, it appears that DTE misunderstood Staff's analysis. Staff did not look at DTE's 2021 forecast from a prior rate case, but looked at the forecast it submitted in this case, in January of 2022, after the storms of 2021. DTE failed to show any logical relationship between its January 2022 overprojection of 2021 spending and the historical events of 2021. In addition, while DTE has indicated it intends to pursue a new cable replacement program, it did not separately forecast those

> expenses in its evidentiary presentation in this case. As noted above, Mr. Bellini also discussed efforts the company is undertaking to reduce its outage restoration expense, although it also has not forecast the impact of those activities. In the absence of greater detail presented by DTE, Staff's analysis appears reasonable. [PFD, p 289.]

The Company disagrees, maintaining that it properly supported its requested cost recovery as outlined above. There is also no basis for the PFD's suggestion that the Company misunderstood Staff's analysis. The Company understands that "Staff's recommendation is based on [sic "the"] ratio of the Company's 2021 actual spend to forecasted spend for the same period" (Staff's Initial Brief, p 92), but the point remains that 2021 *is* historical and was impacted by COVID and storms (Bellini, 7T 1774-1775). The standard is preponderance of the evidence, not "the absence of greater detail" as the PFD suggests. The PFD further proposes that the Commission should consider requiring DTE Electric to file a new lighting depreciation case sooner than the December 2024 date specified in the Commission's December 6, 2018 Order in Case No. U-18150. (PFD, p. 626-627). The Company disagrees with this proposal. The Commission approved the current depreciation rates in the Company's last depreciation case, Case No. U-18150, based on the settlement agreement reached amongst the parties in that case. The Commission also established that the Company should file a new depreciation case no later than December of 2024 (U-18150 Order, p. 2). This proposal requiring a stand-alone lighting depreciation case should not supersede the agreement reached amongst the parties in Case No. U-18150 and should be disregarded. In addition, the PFD itself recognizes the long-term implications of deprecation rates and their impact on net plant balances[84] which contradicts the PFD's recommendation to file a new depreciation case sooner than previously ordered by the Commission.

[84] "That said, depreciation expense is tracked and will reduce plant balances over time; the depreciation reserve reduces the rate base to which a rate of return is applied in determining revenue requirements, so the value of the additional revenues paid to DTE to cover depreciation expense will be preserved through this process" (PFD, p. 627).

D. Demand Response (DR) Programs and DTE Insight

DTE Electric plans $9.7 million of capital expenditures for its Demand Response (DR) portfolio for the projected test year, consisting of Interruptible Air Conditioning (IAC) ($3.3 million), Programmable Controllable Thermostats (PCT) ($3.5 million), and Other DR Programs and Pilots ($2.8 million million). (Farrell, 7T 1659; Exhibit A-12, Schedule B-5.6, page 1, column (f)). DTE Electric also spent $5.9 million in 2020 and plans to spend $19.9 million in the 22-month bridge period ending October 31, 2022 (Farrell, 7T 1658-1659, Exhibit A-12, Schedule B-5.6, page 1, columns (b) and (e)).[85] (See generally DTE Electric's Initial Brief, pp 113-17). The PFD states:

> The only disputes in this category involve the expense projections for "other demand response pilots" shown on line 3 [of Exhibit A-12, Schedule B5.6.] For the reasons discussed in section IX below, this PFD concludes that the project costs of the residential window air conditioning pilot, the residential generation pilot, and the commercial and industrial customer storage pilot should not be approved. [PFD, p 294.]

The Company disagrees regarding the latter two pilots and discusses them below as the most logical location.

1. Residential Generator Pilot

The Company plans to invest $0.46 million in the bridge and test periods to conduct a residential customer-owned natural gas generator pilot. The pilot will leverage a third-party service provider's platform using telemetry to shift customers' load to the electric generator in real-time peak events. Pilot participants will benefit by receiving an incentive from the Company and reduced electric bills during peak events (Farrell, 7T 1689-1991; Exhibit A-12, Schedule B5.6, page 1, line 3, columns (c) through (f)).

[85] A breakdown of the capital expenditures is shown on Exhibit A-12, Schedule B5.6, page 2. The associated O&M expenses are shown on Exhibit A-13, Schedule C-5.9, line 9 (Farrell, 7T 1659).

Staff recommended capital expenditure disallowances of $183,631 in the bridge period and $235,069 in the test year, indicating its view that the pilot is "not yet very well developed" and that shared learnings might be available from a similar Consumers' pilot. (Doherty, 8T 5528-5529). Mr. Farrell responded that much progress has been made in the development of the pilot since the first of the year, including an RFI process and the selection of Generac Grid Services for the implementation of the pilot. The Commission should approve the pilot because it is moving forward as planned and the Company is committed and prepared to launch a successful pilot (Farrell, 7T 1701-1702).

Staff responded that "[w]hile the Company's rebuttal does provide useful information on the proposed residential generator pilot and shows commitment from the Company to move forward, it does not address all of Staff's concerns" (Staff Initial Brief, p 94). The Company thought that it addressed Staff's concerns, but Staff states "[t]he Company does indicate plans to speak with Consumers Energy about the pilot (7 TR 1702.) but Staff is not aware of any results of that conversation or if it has taken place" (*Id*, p 95). The PFD states:

> This PFD finds that DTE did not establish that it has a well-thought-out pilot program. Clearly, when it filed this case, it had just a germ of an idea. Mr. Farrell's rebuttal does not provide the terms of the arrangements between DTE and its customers, it does not include an estimate of the full cost of the pilot, and it does not address all the elements the Commission has requested for pilot approval. Putting all that aside, it is not appropriate for DTE to offer a pilot program design in rebuttal and expect the parties to be able to evaluate it. [PFD, p 545. See also, p 593]

The Company disagrees with the PFD's assertions. The PFD indicates that the Company did not provide program specific information until the rebuttal, but that is incorrect. Witness Farrell's direct testimony, and as indicated above, details how the pilot program will work, provides an exhibit regarding capital costs, and only then provides additional detail in rebuttal in response to the direct testimony of others. Additionally, as the pilot program was progressing during the

pendency of the case, it is logical that additional information and updates would become available. The Company's commitment to and continued progress with the pilot should not be discounted. Therefore, the Company maintains that it properly supported its proposal and the $0.4 million capital expenditure.

2. Battery Storage Demand Response Pilot

DTE Electric plans to invest in a battery energy storage pilot using a behind-the meter (BTM) lithium-ion battery storage system (BESS) at C&I customers' sites. The pilot is designed to test the ability to achieve peak demand shaving or shifting during demand response events, targeting C&I customers enrolled on Rates D4, D6.2 or D11 (excluding sites or load under Rider 10) since these customers are more suited to pilot participation due to their peak load profiles, outdoor space availability and operational capabilities. The pilot is appropriate because the Company needs to gain experience with the application of storage technology by end-use customers and interactions with the wholesale market in order to develop well-designed tariffs and related pilot programs for customer-owned battery storage, as indicated by the August 11, 2021 Order in Case No. U-21032. The Company forecasts $2.8 million in capital expenditures (Farrell, 7T 1684-1689; Exhibit A-12, Schedule B5.6, page 1, line 3, columns (c) through (f)).

Staff "support[ed] the idea of the pilot," but recommended that the Commission deny the pilot based on the belief that the Company's proposal lacked specific details about how the pilot will be operated or implemented (Mathews, 8T 5282-5283). Mr. Farrell responded that the pilot is sufficiently developed, explaining that since this case was filed, the Company completed both the RFI and RFP processes. The Company selected Hitachi as the pilot integrator and executed the contract in Q1 2022. The size of the batteries will be 500kW/2MWh total at two customer sites to reduce peak customer and system demand over an event of up to 4 hours. Therefore, the

Commission should approve the bridge period expenditures of $1,356,847 and test year expenditures of $1,514,933 (Farrell, 7T 1702-1703). The PFD states:

> This PFD recommends disallowing the C&I Battery Pilot costs, at least currently. DTE demonstrated that it is moving forward with the pilot, but the utility's rebuttal testimony and briefing strangely neglected to address Staff's specific concerns about the lack of key details about the structure of the pilot program. While DTE apparently believes it is "unclear" what information Staff sought, the testimony from Mr. Mathews was unambiguous regarding the topics that Staff believed needed further development to evaluate the overall value of the pilot proposal [citing 8T 5383]. Accordingly, this PFD agrees with staff that it is reasonable for DTE to request approval for funding to be included in rates after the details of the pilot are further developed and clarified. [PFD, pp 543-44.]

The Company disagrees, noting that that it remains unclear what additional information Staff may desire to allow the pilot, particularly after supporting the idea and acknowledging the Company's progress. Specifically, the PFD alleges that the Company failed to comment on Staff's question on customer battery utilization outside of Company called events.[86] However, the Company describes this in Witness Farrell's direct testimony, indicating that the customer will have the option to use the battery storage outside of an event in a frequency and duration to address their facility's day-to-day needs. [87] Additionally, the PFD alleges that the Company did not respond to Staff's inquiry regarding event notification.[88] Again, this was described in Witness Farrell's direct testimony. Customers taking part in this pilot will be notified of scheduled demand events at least the day prior to the event and shall be notified immediately of any emergency events called.[89] Continued work with the customer will help the Company gain insight on how best to alert customers to these events, which will help strengthen the program in the future. The Company

[86] PFD p542

[87] 7 Tr 1685-86

[88] PFD, p542

[89] 7 Tr 1685

maintains that it adequately supported the pilot while continuing to progress with the program, so it should be approved under the applicable standards discussed above.

E. Information Technology

DTE Electric's Information Technology (IT) investment spending is part of the DTE Five-Year IT Plan, which categorizes IT investments into an IT Investment Portfolio, with IT Investment Categories (see the matrix at Sharma, 7T 1930; Pizzuti, 7T 2162). Total IT capital spending was $139.6 million in the 2020 historical test year and is projected to be $279.3 million for the 22-month period ending October 31, 2022, and $159.6 million for the projected test year (Sharma, 7T 1925; Exhibit A-12, Schedule B5.7, page 1, line 11, columns (b), (e), and (f)).

It bears emphasis upfront that if the Commission disallows a capital project that is for a shared asset, then for consistency it must also remove the revenue related to that asset from projected net operating income (Crozier, 7T 2394; Uzenski, 7T 2786-2787). Exhibit A-43, Schedule HH1, column (e) shows the reduction to shared asset revenue for each project proposed for disallowance by Staff.

Staff's Initial Brief, p 135, states: "Staff agrees with this argument. If the ALJ and the Commission adopt Staff's IT project disallowances and Enterprise Automation disallowances, the shared asset revenue for those disallowances should also be adjusted as shown on Exhibit A-43, Schedule HH1. These revenue adjustment impacts are not reflected in Staff's initial brief." The PFD does not reflect the revenue adjustment impacts as well.

The PFD is critical of DTE Electric's evidentiary presentation (*e.g.*, PFD, pp 29-308), asserting, for example, that "the documents DTE provided for the record in this case do not appear to comply with the Commission's instructions," that the Company's cost estimation process "lacks credibility," and that certain projects "are essentially placeholders… with the company's focus on

'spending' approved dollars, not meeting any particular or definitive project scope" (*Id,* pp 299, 301, 308). The Company does not dispute the existing filing requirements, but otherwise disagrees with the PFD. DTE Electric has made significant efforts to address feedback from Staff and the Commission in Case No. U-20561 by providing exhibits with additional project details. These exhibits include all of the requested data and the associated workpapers, which contain project details, investment scope, cost breakdown estimates, benefits, and alternative and cloud strategy for investments in the test period. (Sharma, 7T 2129; Pizzuti 7T 2251). Over the course of the Company's last three rate cases, which have spanned over six years, the Commission has asked for increased levels of detail around IT spending. DTE Electric has complied with each of these requests with new and expanded exhibits and workpapers. Specifically, DTE Electric has created a new exhibit showing project costs, timelines and benefits (Exhibit 23, Schedule M-4), detailed business cases for each project (Exhibit A-24, Schedule N1.2 and associated workpapers), variance summaries (Exhibit A-24, Schedule N2.2), a discussion of project need and alternatives (throughout testimony), and evidence of spending for historic and year-to-date spending (Exhibit A-12 schedules B7 to B5.7.9).

Yet, the PFD suggests that the Company has not met the Commission's ever-increasing evidentiary requests. The Five Year IT plan that the Company was instructed to file with the Commission lays out the capital planning process and the evaluations that are undertaken to complete a project. For many IT projects, the key factor for implementing a project may not be financial benefit. Hence, the Company's Project Prioritization Score ("PPS") system considers many different factors that are laid out in significant detail in the exhibits and workpapers for those projects, including 1) strategic alignment to company's priorities and goals, 2) customer experience, 3) employee engagement, 4) affordability and growth, 5) cost benefit, 6) operational reliability, and

7) foundational capability. 7 T 2166 The PFD, however, puts significant emphasis on a lack of cost benefit analyses and project change orders. The Company does include a cost benefit analysis where appropriate. Although it may not be calculated in the manner Staff would prefer, this does not mean that the Company's planning process is deficient, nor does it warrant a wholesale disallowance of project costs.

The record reflects that DTE Electric has a robust IT capital investment planning process with output from that process included in this case. Exhibit A-12, Schedule B5.7 summarizes IT capital cost by portfolio. Exhibit A-12, Schedules B5.7.1 through B5.7.9 present the capital spending in each portfolio. Exhibit A-24, Schedule N1 presents the executive summaries for each business case associated with each IT project over $250,000.[90] The Company also added a new Exhibit A-24, Schedule N-3 Revised to address feedback from the Commission and Staff in Case No. U-20561 (see generally, May 8, 2020 Order, pp 151-53). This new exhibit provides a greater level of detail for each of the IT projects, presented by year and then in portfolio/project order, with details around investment scope, cost estimates, benefits, considered alternatives, and cloud strategy (Sharma, 7T 1927, 1934). In sum, DTE Electric has taken significant steps in modifying its evidentiary presentation for IT projects consistent with each new Commission order.

1. IT Projects with a Level 1 Cost Estimate

Staff proposed "a complete [$50,726,000] disallowance of the projected costs associated with the 26 business cases identified by the Company as having a Level 1 cost estimate," characterizing them as insufficiently supported (Rogers, 8T 5344). The PFD agreed (PFD, p 324. See also, pp 325, 330-31, 344, 367, 371).

[90] There are also 44 projects with IT capital spending less than $250,000, but which are necessary investments to collectively support the IT Portfolio (Sharma, 7T 2112; Exhibit A-12, Schedule B5.7, page 1, line 18).

The Company disagrees. Investments are marked as "Level 1" only because of the timing of the estimate in the multi-year Annual Planning Cycle (APC) process rather than indicating the accuracy of the estimated costs, so this designation should not lead to an assumption that known cost details are insufficient or will result in significant variance (Sharma, 7T 1927-1928, 2129). The Company also submitted cost breakdown information with Exhibit A-24, Schedule N3 Revised (Sharma, 7T 2129).

Staff also indicated concerns regarding the effectiveness of using historical spend for computing Level 1 cost estimates for "new projects without historical or projected spend prior to 2023" (Rogers, 8T 5343-5344). Mr. Sharma responded by explaining why historical spend is a valid benchmark for estimating future spend for each of the Level 1 projects, as the projects are either considered repeatable, like IT projects executed in prior years, or similar in scope or complexity to other IT projects (7T 2130-2133).

"Repeatable projects" (6 projects totaling $9.2 million as shown in Table 1 at 7T 2130) are those where the scope, implementation and technical details, resource requirements, and timelines are very well defined. The historical spend analysis provides a high degree of confidence for the Level 1 cost estimate, and progression to Level 3 estimation would result in little to no variance, so the costs should be approved (Sharma, 7T 2130).

Those Level 1 projects that are "like IT projects executed in prior years" (14 projects totaling $34.7 million, as shown in Table 2 at 7T 2131-2132), include projects with similar work to recent project implementations. These projects have a dedicated team of subject matter experts that can provide information and historical reference for cost estimation. In most cases, there are also existing vendor relationships, and the vendors can further advise on scoping and estimation efforts.

Thus, there is minimal cost variance as these projects progress to Level 3 estimation, and their costs should be approved (Sharma, 7T 2130-2131).

Finally, there are also "new technology projects comparable in scale and complexity" (six projects totaling $6.9 million as shown in Table 3 at 7T 2132) that do involve new technology implementations; however, the scope is defined, and the cost estimates were developed based on historical labor estimates for implementing technologies that are comparable in scale and complexity. Therefore, their costs should be approved (Sharma, 7T 2132).

The Company maintains that it properly supported the projects under the "preponderance of the evidence" standard,[91] and that Staff's doubts about cost accuracy do not justify a disallowance as the PFD recommends. [92] Staff's proposed remedy (100% disallowance, which the PFD similarly recommends) is also inconsistent with Staff's reasoning, particularly since Staff acknowledges that the Company provided information "necessary to understand the scope of the project" (Staff Initial Brief, p 99), and Staff did not dispute the projects based on reasonableness or prudence. Assuming for argument's sake that there is some merit in Staff's concern about a "lack of precision and uncertainty of Level 1 cost estimates," then there might be a basis to consider a range of outcomes, as discussed below regarding projects with Level 2 costs estimates. But there is no sound basis to assign $0 to the projects for a perceived lack of precision. Lack of precision does not equate to lack of existence. Staff's proposal for no recovery based on an alleged uncertainty about whether the

[91] *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence.").

[92] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

Company is 100% accurate is broad sweeping and does not consider the significant support that DTE Electric has provided for these projects.[93] Therefore, the project costs should be approved.

2. IT Projects with a Level 2 Cost Estimate

Staff proposed a 20% ($36.0 million) capital expense disallowance ($19.596 million in the ten months ending October 31, 2022; $16.353 million in the projected test year) for all 108 projects, reasoning that "[w]hile Level 2 costs estimates are more mature and include a breakdown of cost criteria, these projects do not have a definite scope or schedule. As a result, these projects are incomplete" (Rogers, 8T 5345). The PFD agreed (PFD, p 324. See also, pp 325, 330-31, 345, 368, 376-78).

The Company disagrees because, as outlined in Mr. Sharma's testimony and further supported by exhibits and workpapers, the Level 2 projects are based on defined and detailed scopes and timelines and are vetted by all IT departments/teams during the cost estimation process. Also, 92 of the 108 Level 2 projects ($31.5 million) were in progress at the time the Company filed rebuttal testimony so they are certainly defined and scheduled (Sharma, 7T 2134).

The PFD/Staff's proposed 20% disallowance also neglects that the Company has consistently spent close to its Level 2 estimate or higher. For example, there was just a small 2% overspend variance ($103.3 million projected spend compared to $105.4 million total actual spend) for the 68 projects greater than $0.25 million completed as requested in Case No. U-20561 for the year 2020 (Sharma, 7T 2134-2135; Exhibit A-42, Schedule GG3, 2020 IT Project Historical Spend Variance Comparison).

[93] See, for example, *Entergy Gulf States, Inc v Louisiana Public Service Comm*, 730 So2d 890, 901 (1999) (reversing agency's decision as "untenable" and finding all its reasons to be "arbitrary or capricious or unsupported by the record"); *Bureau of Health Care Services v Pol*, unpublished opinion per curiam of the Court of Appeals, issued June 23, 2016 (Docket No. 327346; 2016 WL 3452174 at * 7) (reversing agency decision).

The PFD asserts "that [this analysis] would make sense only if the primary goal of the rate case prudency review is to assure that DTE will [be] spending at least a specific amount of money on IT projects as a whole" (PFD, p 323). The PFD neglects the Company's point, which is that even assuming inaccuracy in individual project estimates (as Staff suggested), the over-projections and under-projections offset each other, trending back towards the overall projection (a collective variance close to 0). Just as there was a 2% variance for the 68 projects in Case No. U-20561, a similar overall projection accuracy can be expected for the 108 projects at issue here.

The Company also disagrees with the PFD/Staff's 20% disallowance because it is arbitrary and unsupported. Staff chose 20% by equating the Level 2 cost estimates with the American Association of Cost Engineering (AACE) Class 3 estimates and used the lower bound of -20% as the basis for its proposed disallowance (Rogers, 8T 5346). The AACE is just one method of cost estimation, and even if it were applicable, Staff's 20% proposal neglects that the AACE class 3 cost estimate also provides an upper bound of +30% (Sharma, 7T 2134). Also, while the Company does not agree that the Commission should apply any percentage disallowance, it would be more accurate to compare Level 2 estimates to AACE class 2 estimates with a -15% to +20% range (Sharma, 7T 2135-2136).

Therefore, the PFD/Staff's proposed 20% disallowance should be rejected as unsupported and contrary to both the Company's supporting project level detail and to history demonstrating that the Company's overall IT investment does not come in 20% under budget (Sharma, 7T 2136-2137; Pizzuti, 7T 2251).

3. IT Projects without Business Cases

Staff initially recommended a $1.87 million disallowance ($0.36 million for the bridge period; $1.51 million for the test year) for five projects without supporting business cases. The

Company agreed with Staff's $1.51 million test year reduction, but in rebuttal submitted a business case for consideration of a $0.36 million recovery (Sharma, 7T 2137; Exhibit A-42, Schedule GG1 MIGP – Integrate DTE Insight Program business case). Staff's Initial Brief, pp 117-19, maintained Staff's position, but revised Staff's proposed disallowance to $1,539,000 ($0.325 million in the bridge period; $1.214 million in the test year) for accuracy.

The PFD "finds Staff's adjustment excluding the expense projections for this item as shown in Exhibit S-12.7 should be adopted" (PFD, p 367. See also, pp 375, 377). The Company appreciates the PFD/Staff's revision for accuracy, but respectfully maintains that it should recover the $0.36 million based on the business case as indicated above.

4. IT Project Spend Capitalization Policy, and Proposed Disallowances

For convenience and continuity of discussion, IT O&M is addressed here with other IT issues (although the overall discussion concerns capital expenditures), due to the nature of Staff's proposals to (1) shift some IT capital expenditures to O&M expense, and (2) disallow O&M expense. The Company disagrees with both of Staff's proposals, as discussed below.

i. Staff's shifting proposal.

Staff recommended a $7.71 million disallowance, reasoning that costs for some IT projects (ClickSoft Application Health; Distribution Application Health; Fuel Supply Application Health; Fermi Enhancements; and DERMS Implementation) were improperly categorized as capital expenditures when they should be O&M expenses (Wang, 8T 5228-5230). Instead of shifting costs from capital to O&M (which Staff and the Company agreed would be appropriate for any capital disallowance, as further discussed in the next section), the PFD appears to recommend a capital disallowance without a corresponding shift to O&M, stating:

> Given the limited support DTE provided for its IT capital expenditures generally, this PFD recommends that the projections identified by Staff be excluded from rate

> base, but rejects Staff's adjusted O&M transfer. DTE will capitalize what it decides can be capitalized of the future bridge period and test year expenses, and providing the funding in O&M will not prevent that. [PFD, p 372.]

On the other hand, in the context of discussing the Corporate Support Group, the PFD "concludes that it is reasonable to increase the O&M expenses by the amount requested by Staff" for "consistency." (PFD, p 494).

IT is unclear if the PFD is recommending a disallowance, however, the Company disagrees and maintains that any disallowance or shifting of costs should be rejected based on the Company's capitalization policy and the record. As discussed in section II above, it is improper for the PFD to suggest that some additional level of detail was required or that the Company otherwise should have further addressed undisputed matters. The Company further notes that the PFD's discussion confusingly combines Staff's shifting proposal (summarized above and discussed below) and Staff's additional O&M disallowance proposal (discussed in the following section), and then discusses them in two different places (PFD, pp 368-72, and 494-96).

Staff's basis for recommending the O&M shift is an assumption that the ClickSoft, Distribution Operations, and Fuel Supply IT projects are for maintenance to existing systems and do not provide the "significant, additional functionality" required for capitalization (Wang, 8T 5228-5229). Company accounting expert Uzenski explained that the application changes that are capitalized in the projects provide new functionality that did not exist previously, as requested by the business unit, and provided specific examples of new functionality for each project. The ClickSoft project includes minor enhancements, which will be expensed to O&M as incurred and not reflected in the capital forecast. However, the programming changes that add significant functionality will be identified in the third quarter of 2022 and only the upgrades and costs that agree with DTE Electric's policy will be capitalized. (Uzenski, 7T 2793).

With respect to the Distribution Operations IT projects, some of the updates include upgraded VPN access for Tree Trim Contractors to enable seamless access to Vegetation Management solutions for scheduling, dispatching, and completing jobs and the addition of new database instances to support the expansion of Tree Trim activities. Other Distribution Operation IT enhancements include the purchasing of hardware and servers to support re-platform initiatives (PSO and OSA) and updated power engineering software to utilize features provided in a newer version of software and account for new data attributes from ESRI system upgrades. (Uzenski, 7T 2793-2795).

The Fuel Supply project implementations include a variety of enhancements relating to automated processing of Fuel Quantity information and Pet Coke fuel invoices as well as the implementation of replacement software to integrate coal train car location information into the Automated Rail Receipt (ARR) application. Accordingly, since the projects result in significant additional functionality which did not previously exist, they meet the criteria to be capitalized. (Uzenski, 7T 2793-2795).

Therefore, the Company appropriately responded to Staff's indicated capitalization concerns (that the projects "are not being properly categorized between capital and O&M costs" (Staff Initial Brief, p 127) – not that they should be disallowed) and otherwise supported its projects, and their corresponding costs should be approved.

Additionally, the $7.71 million proposed by Staff appeared to include a duplicative disallowance for the Company's DERMS project. (Sharma, 7T 2138-2139). Staff's Initial Brief, pp 77-78, and 132-33, later asserted that Staff recommends two separate DERMs disallowances – one for duplicative costs, and the second because the DERMS project allegedly is in a preliminary stage, and allegedly not eligible for capitalization. Staff alleges that because the Company has not selected

a vendor this is indicative that the project is in its preliminary stages and, therefore, costs should not be capitalized. Staff has assumed, without evidence, that the Company's capital projections for software development include project costs that must be expensed to O&M under GAAP. They do not. The Company's capital request reflects only those costs properly capitalizable (*i.e.*, starting with the development stage) (Uzenski, 7T 2793).

The PFD states:

> Based on DTE's assertions that the capital expenditures in its projection for this line item are only intended to reflect the development stage, this PFD concludes the expense projection should be rejected because it is premature for DTE to project the development stage costs when it is still conducting a preliminary analysis. [PFD, p 375.]

The Company maintains that its capital request reflects only costs that are properly capitalizable, so they should be approved.

ii. Staff's disallowance proposal.

Staff proposed a $6.86 million O&M reduction and suggested that this disallowance is related to the IT capital expenditures that it proposed to disallow (see generally, Rogers, 8T 5342; Exhibit S-12.8). Staff also proposed an additional 0.5% ($2,876,229) IT O&M disallowance based on the general assumptions that "[g]iven that 10% of capital cost is typically used as a baseline for IT O&M costs and that it varies from 6-13% in actuality, Staff recommends the midpoint of 9.5% instead be used" (Wang, 8T 5236). The PFD recommends adopting both of these disallowances (PFD pp. 495-496).

In addition to the discussions above that capital expenditures should be approved, the Company disagrees with the proposed disallowances for two additional reasons.

First, Staff's proposed IT O&M reductions were not included in the Company's requested revenue deficiency. Instead, the Company's projected O&M uses 2020 historical investment and

adjusts for inflation and other specific projection adjustments (Exhibit A-13, Schedules C5). Since the Company's projection adjustments did not include the amounts at issue, they should not be disallowed (Uzenski, 7T 2777).

Second, if the Commission were to decide to disallow any O&M expenses, then that disallowance should be reduced to the portion that applies to DTE Electric only. The O&M cited by Staff is the amount supporting all DTE Energy users of the assets. The IT O&M costs recorded at DTE Electric are based on the bill down of costs from the LLC, or about 73% of the total, as reflected by Exhibit A-43, Schedule HH1, column (f). Therefore, if the Commission disallows any O&M related to these IT projects, the amount should be calculated in accordance with column (f), which applies to DTE Electric only. (Uzenski, 7T 2777-2778).

"Staff agrees with this argument. If the ALJ and the Commission adopt Staff's IT project disallowances and Enterprise Automation disallowances, the shared asset revenue for these disallowances should also be adjusted as shown on Exhibit A-43, Schedule HH1. These revenue adjustment impacts are not reflected in Staff's Initial Brief" (Staff Initial Brief, p 135. See also, p 172: "Staff agrees with the Company that the O&M adjustment should be attributable to DTE Electric only, therefore reducing the recommended disallowance for projects with Level 1 and Level 2 cost estimates by 27%").

Staff also proposed an additional 0.5% ($2,876,229) IT O&M disallowance based on the general assumptions that "[g]iven that 10% of capital cost is typically used as a baseline for IT O&M costs and that it varies from 6-13% in actuality, Staff recommends the midpoint of 9.5% instead be used" (Wang, 8T 5236).

The Company also disagrees with Staff's 0.5% reduction analysis and resulting proposal. Staff incorrectly assumed that all IT O&M is related to capital projects. Instead, as the Company

explained in response to Staff's discovery questions (included as Exhibit A-43, Schedule HH2), not all IT expenses are associated with a capital project, and the O&M noted in individual business cases is not used to calculate projected O&M. IT O&M expense includes cloud computing fees, hardware and software defect remediation, business support service, and IT administration. Thus, Staff's proposed disallowance should be rejected (Uzenski, 7T 2778-2779).[94]

Therefore, the Company properly supported its position on the record, [95] and the Commission should deny any proposed disallowance.

5. IT Projects Historical Spend Analysis

Staff proposed a $1.85 million disallowance based on calculations shown at Wang, 8T 5231-5232. The PFD states:

> This PFD agrees that the projected historical underspending in one year, 2020, is not a sound basis to adjust DTE's 2021 projection in the absence of any other evidence that its 2021 estimate of actual 2021 spending is inaccurate. This PFD does agree that the bridge and test year projections for the one line item for which Staff proposed an adjustment should be adjusted accordingly. As discussed above, DTE does not presented [sic] a detailed basis of its cost projections and 2022-2023 spending is not known at this point. Additionally, although DTE relies on its project prioritization to support its spending projections, it does not have prioritization scores for its 2022 spending. [PFD, p 374.]

The Company agrees that there is no sound basis for a 2021 disallowance (See also, PFD, p 378), but disagrees with the proposed disallowance for 2022-2023. Staff extrapolated data from a

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[94] Staff's Initial Brief, p 170, responded: "The values used in Staff's IT O&M disallowance were not assumptions but provided by the Company in discovery responses. (See Exhibit S-7.49.)" It is true that the Company provided the *values*, but those values were in the context of responding to Staff's request concerning one specific project (Exhibit S-7.49, p 4). Then, Staff incorrectly *assumed* it was appropriate to apply those project values to an across-the-board IT disallowance, including other matters such as cloud computing fees, as discussed above.

[95] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

very small sample size to arrive at the conclusion that a portion of IT project cost estimates should be disallowed. The entire exercise is unnecessary and leads to an incorrect conclusion because (1) the projects are prudent and in progress, (2) the cost estimates are very detailed and commensurate with the scope of work being completed, and (3) the actual expenditures for the 2020 historical period on the sample of projects chosen by Staff was higher than the projected spend in Case No. U-20561. There is no basis for Staff's calculated $1.85 million disallowance for project underspending, where even the projects in Staff's sample were not underspent (Sharma, 7T 2139-2140; Exhibit A-42, Schedule GG4, showing projected spend of $8.2 million and actual spend of $12.3 million).

The Company further notes that the PFD agrees that there is no basis for a 2021 disallowance. It is inconsistent and unreasonable for the PFD to apply the same methodology that it rejected for 2021 to a proposed disallowance in 2022-2023. Accordingly, there should be no disallowance in this category.

6. Other Individual IT Project Disallowances

As general background, the Company has many projects that are clearly targeted at achieving cost savings, improving electric and operational reliability, and ensuring the safety of customers and employees. The Company also evaluates the strategic nature of a project and if it supports a broader and multi-year strategy with a focus on improving customer service and customer satisfaction, and providing alternative options (digital channels and/or products and services) for customers to engage with the Company and their electrical usage (Pizzuti, 7T 2252).

The Company also has a goal of providing Distinctive Service Excellence (reflected for example in the DTE IT 5-Year plan), and appropriately identified product and service providers that are considered the "best" in delivering the key elements of a distinctive experience. The

Company also researched and benchmarked peer utilities, which identified key trends and confirmed that the Company is on the right path with adding more self-service transactions to its digital channels, and revealed best practices that the Company has applied (Pizzuti, 7T 2257-2261; Exhibit A-44, Schedule II1, II2, and II3).

The PFD agreed with Staff's recommended disallowances for three IT projects (discussed in subsections i – iii below) that support a multi-year strategy to improve the customer's transactional journey. Evaluating these projects as individual, stand-alone projects, without considering how they fit into the context of delivering Distinctive Service Excellence, overlooks this additional value that they provide (Pizzuti, 7T 2253). The PFD also largely agreed with Staff's proposal for a total of $13.4 million capital disallowances for six IT projects (Reservation Application; Network Advanced Metering Infrastructure Support; Controllers Financial Planning Tool; Virtual Desktop Infrastructure (cost recovery recommended at PFD, p 379); Command Center Stand Up; and GRC Tool Expansion for Regulatory Assets). The Company disagrees because the projects are prudent, necessary and well supported, as outlined below, and further detailed in Mr. Sharma's rebuttal testimony (7T 2140-2145).

i. Platform integration-SAP integration.

Staff proposed a complete disallowance of integration ($1.836 million in the bridge period; $0.514 million in the projected test year), reasoning that the Company "did not provide any benefits to customers, including savings, safety, or reliability in the business case… [and] did not identify any alternatives considered for the investment" (Rogers, 8T 5353). The PFD agreed, stating:

> This PFD concludes Staff's recommendation should be adopted. DTE's arguments about the benefits of integration are generic and do not justify any particular level of expenditure. DTE made no effort to quantify the benefits associated with the proposal, and this PFD finds that DTE has not justified the expenditure. [PFD, p 366.]

The Company –disagrees. The benefits of integration, while presented in broad terms, are not generic. Like many of the Company's projects, the purpose of integration is to remove disparate legacy systems to allow for greater functionality and smoother experiences for the user. (Pizzuti, 7T 2253-2254). While customers may view their balances and receive their bills without the project, as Staff suggests, this does not mean that the project is not a reasonable and prudent project to implement. Integration allows the Company to streamline interactions and all communications to the customer and ensure that if they do call or use one of the Company's self-serve channels that these sources of customer information are available, reliable, and dependable. This leads to a better customer experience. The SAP integration tool will not only support the Company's digital projects as noted by the PFD (p. 365), but all front-end customer experiences that require the exchange of data will benefit from this project. Customer Service Representatives (CSRs) also benefit from having higher quality, dependable data since they can more quickly and comprehensively respond to a customer's request or investigate a customer concern. (Pizzuti, 7T 2254)The Company has not articulated the quantitative benefits from this project because the benefits of integration are inherent. Regardless of the way the customer interacts with DTE, either through our digital channels, the Contact Center, or with a field employee, the Company will be able to better serve the customer with more timely and accurate data.

ii. Automation application monitoring enhancement.

Staff proposed a complete disallowance of automation application monitoring enhancement ($2.4 million in the bridge period; $0.4 million in the projected test year), reasoning that the Company did not demonstrate that it "improves the safety and reliability of electric service to customers… [so] this project falls short of being a prudent expense at this time" (Rogers, 8T 5354). The PFD agreed, stating:

> A review of the business case documents for this project (one for 2021 spending and one for 2022 spending) show a hodge-podge of technical changes, but nothing about any savings and no quantification of any system improvements. This PFD finds that Staff's position should be adopted. DTE has been given multiple opportunities to present quantification of the benefits of its proposed projects as part of its direct case, but such offerings are not persuasive or reliable when offered in rebuttal. [PFD, pp 346-47.]

The Company maintains that it has in fact quantified the benefits of the project. As stated in Ms. Pizzuti's testimony, the project is expected to improve the SAP Customer Relationship and Billing (CR&B) system's uptime by 1% and reduce unplanned outages by 1%, which equates to an approximately $50,000 per year reduction in IT support time to resolve unplanned events (Pizzuti, 7T 2255). There is also value in avoiding system downtime, which prevents customers from transacting business with DTE Electric in their channels of choice. There are also other non-quantifiable benefits, such as enabling interface monitoring, job monitoring, user experience monitoring, business process modeling, and providing an alert when computing power/performance is low for supporting these processes. (Pizzuti, 7T 2255) These benefits were also provided in testimony. Therefore, the suggestion that the Company has not presented any evidence, or any reliable evidence is not accurate and the Company's requested cost recovery should be approved.

iii. Supporting capabilities – test data and test data management.

Staff proposed a complete disallowance of the test data and test data management project ($0.9 million in the bridge period; $0.3 million in the projected test year), reasoning that the Company did not demonstrate "safety or reliability benefits… [so it would be] imprudent to pass [the costs] on to ratepayers who will receive no benefit" (Rogers, 8T 5355). The PFD agreed, stating:

> This PFD finds Staff's analysis persuasive. Clearly, product or project testing has been a part of the company's IT cost projections to avoid adverse effects; the only benefit of this project may be greater efficiency in avoiding adverse effects, but DTE has not established that or that the efficiency gains justify the expense. [PFD, p 349.]

The Company agrees only that IT projects must be thoroughly tested before they are put into production to avoid adverse effects. The Company maintains that the project provides benefits by increasing the efficiency, and improving the effectiveness, of the Company's IT project testing processes and ability to meet IT project delivery deadlines, and prevent potential defects or issues from occurring downstream of the project (Pizzuti, 7T 2255-2256).

The additional testing functionality and enhanced testing environment provided by this project will allow the Company to bring current its testing processes and practices. While not directly connected with improving electric reliability, all IT investments, including those that support DTE Electric's ability to deliver better electric reliability, safety or more accurate bills, must be tested. (Pizzuti, 7T 2255). The speed and comprehensiveness of the testing will more assuredly reduce the possibility of adverse effects.

Therefore, and as further discussed in the introductory comments regarding strategic context and additional customer benefits, all of the costs for these projects should be approved.

iv. Digital Experience Group (DEG).

Staff recommended a 60% ($3,109,000) disallowance of historical 2020 capital costs associated with DEG, reasoning that "[w]hile Staff supports the goal of eliminating silos and creating a cross-functional team to improve Customer IT, the Company has not provided adequate detail of the customer benefit for this expenditure in relation to the cost… [and] customers are more concerned with reliable, affordable electricity, correct meter reading, and accurate billing" (Armstrong, 8T 5493). The PFD agreed with Staff's proposed 2020 disallowance, and then *sua sponte* recommended a further disallowance for 2021 though the projected test year, stating:

> This PFD finds that the 60% of the 2020 spending on line 42 should be disallowed as recommended by Staff, while the remaining estimated 2021 expenditures and projected bridge and test year expenditures on lines 43 and 49 should be rejected as

> unsupported. This PFD notes that Staff's adjustment to line 49 removed 20%, which this PFD adopted, so that leaves the remaining 80% that this PFD finds should be excluded from rate base. [PFD, p 362.]

The Company disagrees and maintains that it properly responded to Staff's indicated concern and otherwise supported this project through evidence of benchmarking with utility peers demonstrating that customers care about being able to use digital channels to interact and transact business with the Company. Successful results, such as order tracking and enhanced notifications that reduced the need for a customer to call, led to call reduction savings from the Move In/Move Out (MIMO) DEG; and an improved outage web experience and more accurate outage reporting from the Outage DEG investments confirmed the need for these projects and their customer benefits, justifying their full cost recovery (Pizzuti, 7T 2190, 2262-2263).

Therefore, the Company's requested cost recovery should be approved.

v. Prepay billing program.

Staff proposed a total disallowance of the Company's proposed voluntary PrePay Billing Program's capital costs of $8.0 million in the bridge period and $4.6 million in the projected test year. The Company disagrees because PrePay represents an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage or who struggle with paying their bill with today's post-pay billing model. The Company further maintains that the capital expenditures related to PrePay are reasonable and prudent but appreciates Staff's position that recovery for these costs would be pending formal approval of the filed PrePay Case U-21087 (Armstrong 8T 5491; Pizzuti, 7T 2267). The Company understands and agrees that the necessary billing rule waivers are required to proceed with the program. However, the Company disagrees to the extent Staff suggests that the Company should seek costs in a subsequent and separate case even

if the Commission were to approve the necessary waivers prior to the conclusion of this case as the Company has demonstrated that the costs are reasonable and prudent (Pizzuti, 7T 2267).

The PFD noted but did not address the AG's objection,[96] and then stated:

> This PFD finds Staff's analysis persuasive that the program will be evaluated in the separate docket, and if the company receives approval, which is uncertain given opposition in that case, it can then seek cost approval for the program. [PFD, p 366.]

The Company disagrees because Case No. U-21087 was properly addressed above, the expenditures were presented for review in this Case No. U-20836, and they are reasonable as indicated above.

vi. Reservation application.

Staff recommended a total ($0.5 million) disallowance in the 22-month bridge period ending October 31, 2022, reasoning that the cost is unnecessary, there are less expensive options, the COVID-19 pandemic is transforming to an endemic state, and the Company can contact trace and sanitize workspaces and equipment without this software (Rogers, 8T 5348-5349). The PFD indicates agreement, but does not articulate a specific recommendation (PFD, p 330). Appendix E reflects a $0.5 million reduction to capital for the reservation application so it appears that the recommendation is to disallow recovery.

[96] AG witness Coppola proposed a complete ($12.6 million) disallowance ($6.7 million for the twelve months ended 12/31/2021; $1.3 million for the ten months ending 10/31/22; and $4.6 million for the projected test year), suggesting that there is no evidence that customers are seeking this type of service, and questioning whether customers would benefit from it (8T 4805-4806). The Company disagrees because it provided extensive evidence that PrePay is an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage, or who struggle with paying their bills with today's post-pay billing model. The Company further maintains that the capital expenditures are reasonable and prudent, and has provided significant details about the design of the program, customer segments that might benefit most from participating in it (see Exhibit A-44, Schedule II4), enrollments, eligibility requirements, and how Phase 1 of the program will help the Company understand the customers who are interested in PrePay and what they find most compelling about the program (Pizzuti, 7T 2270-2271).

The Company disagrees with all the suggested reasons for disagreement with the reservation application and any associated disallowance. The project started during the pandemic, and although COVID-19 may be transitioning to an endemic state, there are continuing requirements to maintain employee health and safety through social distancing and contact tracing. The program also positions the Company for any future outbreaks. Finally, Staff's suggestion that the Company could contact trace and sanitize used facilities in an effective way without this application neglects the complexity of the manual effort needed to complete contact tracing and sanitizing requirements (Sharma, 7T 2141).

vii. Controllers financial planning tool.

Staff recommended a complete disallowance of the Controllers financial planning tool ($2.187 million in the bridge period and $0.613 million in the projected test year). The Company disagreed, explaining that it had a Level 2 estimate that reflected the costs of the products that were considered, and provided scope details. The project is currently in progress following the Company's selection of one of the alternatives that it considered (Oracle EPM product) as a viable solution to replace the current SAP BPC Planning tool. Thus, Staff's indicated concern has been addressed. Staff also indicated that it is not opposed to this type of investment (Rogers, 8T 5352), and Mr. Sharma's testimony further demonstrates that the investment is prudent and necessary (7T 1958-1959, 2143).

The PFD found that "Staff's adjustment is appropriate," reasoning that the Company initially submitted a placeholder and improperly "substitute[d] a more complete project in rebuttal" (PFD, pp 327-28). The Company respectfully disagrees based on the record and its right to submit rebuttal responding to issues raised by Staff, as discussed in section II above. Even assuming for argument's sake that Staff's indicated concern about cost-estimate accuracy has merit, then the

result should be in accordance with other projects having a Level 2 cost estimate, where Staff proposed, and the PFD recommends, a 20% disallowance (see the discussion above – IT projects with Level 2 Cost Estimate). The PFD's Draconian (100%) disallowance arising from cost-estimate accuracy concerns is inappropriate and contrary to the PFD/Staff's own reasoning. Plainly the cost is not $0, and there is no other sound basis for a disallowance, so the proposed 100% disallowance should be rejected in favor of full cost recovery of $2.8 million based on the record, or at least a Level 2 percentage cost recovery consistent with other Level 2 projects.

viii. Command Center stand up.

Staff proposed a total disallowance of the Command Center stand up project ($0.406 million in the bridge period and $0.044 million in the projected test year) "due to the ambiguous nature of this request" and an alleged lack of evidence regarding how the project will benefit safety or reliability of electric service to customers (Rogers, 8T 5358-5357). The PFD agreed that DTE has not supported the reasonableness and prudence of its expenditures and they should be excluded from rate base. (PFD, p 381.)

The Company maintains that the project is supported and should be approved. Mr. Sharma explained that this investment is required, and that it will establish a physical command center where the Company will be able to monitor critical IT assets with enhanced dashboards allowing improved response times to IT applications trouble events. While this, may not directly relate to improved reliability of electric service, this project relates directly to customers because the critical applications support key business operational processes that allow the Company to fulfill its business processes, operations, and customer service requirements. Mr. Sharma also provided numerous examples of critical assets and applications that are monitored by the Command Center and that directly support customers (Sharma, 7T 2099, 2144).

ix. GRC tool expansion for regulatory assets.

The PFD discusses this area, but does not offer a recommendation (PFD, pp 376-77), so the Company takes exception as discussed below.

Staff proposed a complete disallowance ($0.103 million in the historical year; $0.45 million in the bridge period) reasoning that the benefit of reducing manual labor does not outweigh the project's cost (Rogers, 8T 5360 26). The Company disagrees because there are benefits beyond annual time savings, and cost-benefit was not the only consideration in selecting this as a prudent investment. The investment will ensure that IT assets have the necessary compliance and risk elements associated to comply with regulations and standards. The investment will also manage regulation, business, and technology changes more effectively, and allow the Company to proactively respond to risks (Sharma, 7T 2044, 2145).

Therefore, there should be no disallowance in this area, and if the Commission disallows a capital project that is for a shared asset, then for consistency it must also remove the revenue related to that asset from projected net operating income.

x. Time of use.

AG witness Coppola proposed a complete disallowance ($18.9 million for the bridge period; $11.2 million for the test year), reasoning that the "project appears to be much more than the pilot program approved by the Commission," and recommends "that the Commission suspend any further work and spending on the pilot program until a lower cost path is agreed to by the parties and approved by the Commission" (8T 4803-4804).

The Company responded by explaining that the AG's proposals appear to be based on the incorrect premise that the projected costs are for the pilot; however, the costs are for the full implementation of TOU rates that the Commission directed the Company to achieve for the summer

of 2023. The Company also proposed an alternative TOU implementation plan, with a capital cost reduction of approximately 35% as reflected in Exhibit S-23.01, which Staff supported.[97] The project is critical for the successful implementation of TOU rates, so full cost recovery of TOU IT costs should be approved (Foley, 6T 1146-1147; Pizzuti, 7T 2268-2269).

The PFD states:

> Given that the infrastructure required to support full implementation has not yet been determined, and that there is a 2023 business case that is different from the 2022-2023 business case in terms of objectives and total cost, it is unclear that DTE had any intention of following the 2022-2023 business plan. This PFD recommends that the Commission decline to include the 2022 and 2023 projections in rates, including the projected O&M expenses. DTE's TOU proposals are discussed specifically in section XI below. Once the Commission makes a determination as to an appropriate TOU rate design, it should demand a comprehensive analysis from DTE of all the work done in prior years and the additional work remaining to be done to implement that selected rate design. [PFD, p 344.]

The Company disagrees. As indicated above, the AG's position was based on an incorrect premise. The project is also critical for the successful implementation of TOU rates, so full cost recovery of TOU IT costs should be approved (Foley, 6T 1146-1147; Pizzuti, 7T 2268-2269). The Company also incorporates its discussion in section VIII. D below, taking exception to the PFD's recommendation for further delay in TOU rate implementation, and explaining that the Company's proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), either as originally proposed or as defined in the "Alternative TOU Full Implementation" proposal in DWI-1.1, should be approved, along with related cost recovery.

F. Corporate Staff Group

[97] Staff's Exhibit S-23.01 shows the TOU Alternative capital costs to be $19.5 million ($10.1 million for twelve months ending October 31, 2022 and $9.4 million for twelve months ending October 31, 2023). The Company understands that Staff fully supports the Company's "Alternative" TOU proposal costs as outlined in Exhibit S-23.01, less contingency, and requests that the Commission approve these costs (Pizzuti, 7T 2256-2257). Staff agrees (Staff Initial Brief, p 146).

Corporate Staff Group (CSG) capital spending for physical infrastructure, fleet, and other projects, was $123.0 million in 2020, and is projected to be $227.4 million for the 22 months ending October 31, 2022, and $139.9 million for 12 months ending October 31, 2023 (Uzenski, 7T 2727; Exhibit A-12, Schedule B5.8, page 1, line 10).

1. HQ Energy Center

The HQ Energy Center is a new facility that went in service in November 2021. It includes a steam plant fueled by natural gas, and a chilled water plant for the downtown campus. The Company needed a steam production facility because it depended on purchasing steam from Detroit Thermal, at prices that increased annually, and the Company experienced negative impacts from Detroit Thermal's planned and unplanned outages. The Company also needed a new chilled water system because the current chilled water system was at the end of its useful life (Uzenski, 7T 2732-2733).

The Commission previously approved capital expenditures for the HQ Energy Center (May 2, 2019 Order in Case No. U-20162, pp 46-47). The Commission also approved additional capital expenditures in Case No. U-20561, where the total capital investment was forecasted at $39.4 million, resulting in a lower net present value of the revenue requirement (NPVRR) compared to an NPVRR under the status quo. The project subsequently incurred construction cost increases, resulting in an updated forecasted total cost of $47.8 million. The project still made sense, however, due to Detroit Thermal's rates and other service considerations (Uzenski, 7T 2735).

Staff proposed a "disallowance of $7,700,00 in bridge period capital expenditures for this project. This adjustment would bring the total approved capital expenditures for this project to $40.1 million, or the breakeven point identified in the NPVRR analysis" (DeCooman, 8T 5297). Staff alternatively recommended a partial disallowance that "splits the incremental costs above the

breakeven point identified in the NPVRR analysis between ratepayers and shareholders" (DeCooman, 8T5298). The Company agrees with Staff's alternative recommendation, but the underlying analysis should be updated to reflect a $1.4 million difference between the breakeven point and the updated project costs (Uzenski, 7T 2781-2784).

The PFD states:

> This PFD finds Staff's adjustment should be adopted. DTE chose to base its decision regarding this project on saving energy costs; it did not establish that any such savings materialized. The company's contrary analysis was presented in rebuttal, wrongly incorporated only five months of a year, and failed to reflect any natural gas increases at the same time. DTE's attempt to shrug off the Attorney General's reference to gas prices as "not comparable to Detroit Thermal's full cost of steam service" clearly ignores that gas prices must be an element of its comparison between Detroit Thermal service and the HQ project DTE undertook. Additionally, DTE did not show that it undertook reasonable efforts to confirm its construction costs, including coordinating with the City of Detroit before it presented its savings analysis to the Commission. While DTE also cites "increased AFUDC," it did not establish that increase as reflective of anything other than the company's cost overruns, and as the Attorney General argues, did not establish why it labeled AFUDC as "increased project management costs." [PFD, pp 392-93.]

The Company maintains that it supported its requested recovery, which is based on an update of Staff's alternative recommendation. The Company further notes that the Commission is required to base its decision on the evidence and disagrees with the PFD's suggestions that the Company cannot present evidence in rebuttal (which would improperly limit evidence) and that the PFD can raise new issues (after the record is closed so there is no ability to present evidence on them) as discussed in section II.

More specifically, the breakeven point referenced by Staff was based on the updated $47.8 million spend and the assumption that Detroit Thermal's rates would increase at a compound annual growth rate (CAGR) of 4.5%, consistent with actual rates from 2018-2020, which were the rates assumed in the Company's original analysis (Exhibit A-43, Schedule HH4, column (b)). Detroit Thermal's rates actually increased at a 6.2% CAGR from 2020-2022 (Exhibit A-43, Schedule HH4,

line 2). Using that actual 6.2% CAGR, the NPVRR for the status quo increases to $68.1 million, as compared to $59.7 million in the original analysis (Exhibit A-43, Schedule HH4, line 4, columns (b) and (c)). The updated breakeven point is $46.4 million (Exhibit A-43, Schedule HH4, line 5, column (c)). Using Staff's method of comparing the updated project cost of $47.8 million to the updated breakeven point of $46.4 million, Staff's proposed $7.7 million disallowance becomes $1.4 million (Uzenski, 7T 2782-2783; Exhibit A-43, Schedule HH4, line 6, column (c)).

The PFD states that the Company's update "wrongly incorporated only five months of a year" (PFD, p 392). This is inaccurate and neglects the context. Staff suggested that instead of the Company's updated CAGR relying in part on 5 months of 2022 data (the most recent data available), a CAGR calculation using the three most recent full years of data (2019-2021) could be used, and would produce a lower CAGR. That is mathematically accurate, but reaching back another year in history (to 2019) skews the CAGR downward and neglects the whole point of doing an *updated* analysis. For example, Detroit Thermal's base rate increased pursuant to the August 11, 2021 Order in Case No. U-20824, as Ms. Uzenski observed (7T 2782). The Company maintains that it properly performed the analysis based on the most recent data available.

The PFD was also apparently persuaded by AG witness Coppola, who proposed a $5.2 million disallowance ($3.9 million for a revised cost of new gas service, and $1.3 million of DTE project management), reasoning that the Company did not justify why the cost of installing gas service would increase by $3.9 million, or why its own project management costs exceeded previous estimates (8T 4815-4816). To the contrary, the Company explained in response to discovery request STDE-23.11c that the increased cost of installing gas service was caused by the City of Detroit's requirement to open cut along Fort Street, Third Street, and Plum Street instead of direct boring as the Company originally planned. Further, in response to discovery request STDE-

23.11b, the Company explained that the increase in project management cost was due primarily to an increase in Allowance for Funds Used During Construction (AFUDC). Therefore, these costs are justified and should be approved (Uzenski, 7T 2781).

The PFD's characterization of the Company "attempt[ing] to shrug off the Attorney General's reference to gas prices (PFD, p 392) is inaccurate and neglects the nature of discovery (questions are answered; there is no sound basis to criticize an answer for not responding to some different/unasked question). The Attorney General asked in discovery to: "Provide the CAGR of the Company's GCR factor over the same period." The Company answered accurately:

> The CAGR for the CGR factor is 10.49%. However, the CAGR for Detroit Thermal rates is for the delivered cost of steam, reflecting a full cost of service including their rate base, and is therefore not comparable to a CAGR for natural gas prices. [Exhibit AG-1.63, p 2.]

Therefore, the Commission should adopt Staff's alternative recommendation using the updated $1.4 million difference (updated project costs of $47.8 million compared to updated breakeven point of $46.4 million), resulting in a disallowance of $0.7 million, and the additional capital expenditures should be approved.

2. Enterprise Automation

Enterprise Automation engages in automation, digitalization, and process improvement initiatives across the Enterprise. Robotic Process Automation (RPA) software is used to program automations that perform repeatable, rules-based, and digitized tasks. The Company projected capital costs of $10.5 million for 2021 and $11.0 million per year in 2022 and 2023 (Uzenski, 7T 2737-2738).

Staff proposed disallowances of $0.596 million for 2021 (as not spent), $9.161 million for the ten months ending October 31, 2022, and $11.0 million for the projected test year. The Company agreed with the $0.596 million reduction for 2021, but disagreed with the remaining $9.2 million

and $11.0 million disallowances (Uzenski, 7T 2784). Staff withdrew its recommended disallowance for the ten months ending October 31, 2022 (Staff Initial Brief, p 141) and the PFD found that this issue was resolved (PFD, p 394). The only remaining dispute concerns Staff's proposed $11.0 million disallowance for 2023. The PFD states:

> Regarding the projected test year expenditures, this PFD finds Staff's analysis persuasive that DTE has not established sufficient details regarding the automation efforts it will undertake. It clearly considers its spending target reliable, but meeting a spending target is not equivalent to spending money reasonably and prudently. [PFD, p 395.]

The Company disagrees because it anticipates spending a (now undisputed) $11.0 million in 2022, and plans on using the same methodology to identify, evaluate, prioritize, and execute Enterprise Automation projects to spend the same amount in 2023.

The PFD/Staff's proposed 100% disallowance is also unreasonable and inconsistent. Staff never disputed the $9.9 million of actual spending in 2021, and now does not dispute any of the $11.0 million for 2022, as discussed above. Staff also did not dispute the nature of Enterprise Automation spending and noted that Enterprise Automation has grown 63% since its inception (Rogers, 8T 5364 30). The PFD effectively proposes $0 spending for 2023 on a well-established and undisputed program, which is contrary to the record and unreasonable. Therefore, the Commission should fully approve Enterprise Automation capital expenditures, except for $0.6 million for 2021 (Uzenski, 7T 2784-2785).

G. Marketing Pilots

1. Charging Forward

The Company proposes a Charging Forward Expansion.[98] (See generally, DTE Electric's

[98] The following existing elements of Charging Forward would be extended based on lessons learned: Customer Education & Outreach, Residential Smart Charger Support (Residential Rebates), Bring Your Own Charger, EV-Ready

Initial Brief, pp 147-53, reflecting overwhelming support for Charging Forward Expansion, and responding to various witnesses suggested modifications). The Company generally agrees with the PFD's recommended resolution of the issues, with concerns discussed below.

The PFD appropriately recommends approving the Company's proposed Charging Hubs pilot, but then states:

> Nevertheless, as requested by EVgo, ChargePoint, and other parties, this PFD also recommends requiring DTE to facilitate the siting of third-party charging hubs by providing regularly updated capacity maps with additional information like load serving capacity at a substation and circuit levels, feeder identification and characteristics, substation source, voltage information, and other "last mile" grid information. DTE presumably possesses such information, and it touted its ability to identify areas with sufficient power supply as a reason that it was uniquely suited to build charging hubs. However, DTE did not provide cogent reasons against sharing this grid information to better assist interested non-utility market participants in locating sites that are potentially suitable for charging hubs. [PFD, pp 568-69.]

To the contrary, the Company presented "cogent reasons" for its disagreement with various suggestions that the Commission require the Company to either update distribution hosting capacity maps or publish EV charging maps (Burns, 7T 2515).[99] Ms. Pfeuffer further explained that the Company's hosting capacity map was created to guide development of DERs in an efficient manner and inform planning decisions, in accordance with the August 20, 2020 Order in Case No. U-20147.[100] Proposals to update the map to include loading information raise concerns because load is dynamic and load maps are quickly outdated and involve significantly different analysis than DER hosting capacity. Any attempt to create an up-to-date and accurate EV hosting capacity map

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Builder Rebates, and Charging Infrastructure Enablement (Make-Ready Rebates). The Company also proposes to introduce the following new elements to address identified gaps: Residential Charging as a Service (CaaS), Charging Hubs, Transit Batteries, Transportation Network Company (TNC), Driver Rebates, Income-Eligible Rebates, Commercial CaaS, and Emerging Technology Fund (Burns, 7T 2413-2414. See also Exhibit A-12, Schedule B5.9.2 for a high-level summary of how the Charging Forward expansion is meeting the requirements for a pilot as provided in the February 4, 2021 Order in Case No. U-20645).

[99] A Hosting Capacity Analysis (HCA) is the amount of Distributed Energy Resources (DER) that can be accommodated without adversely impacting operational criteria such as power quality, reliability, and safety under existing grid control and operations, and without requiring infrastructure upgrades (Robinson, 7T 1577).

[100] Company witness Robinson further discussed the Company's HCA efforts (7T 1577-1582).

would require substantial investment in real-time IT infrastructure and significant business process change to serve an undefined need and a small stakeholder group of developers with speculative projects. Plus, the information could potentially be misleading, and the associated costs to implement these changes would effectively subsidize third-party EVSPs at customer expense. Therefore, the suggestions should be rejected (Pfeuffer, 4T 530-35).

The Company also does not agree with the PFD's *sua sponte* recommendation that DTE Electric update capacity maps with additional information, which goes beyond the underlying suggestions by parties (discussed above), based on DTE Electric "presumably" having such additional detail conveniently available to supply to third parties, as indicated in section II above.[101]

> Regarding a future full-scale program proposal, the PFD states:
>
> This PFD recommends that the Commission should direct DTE to present a plan for a permanent program for its currently existing Charging Forward pilots in its next rate case. DTE expressed concern that some elements of Charging Forward

[101] See *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.) See also *Consumers Power Co v. Public Service Comm,* 189 Mich App 151, 180; 472 N.W.2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority."; *Consumers Power Co v. Public Service Comm,* 460 Mich 148, 155-56; 596 NW2d 126 (1999) holding, inter alia, "The Public Service Commission has no common law powers. It possesses only that authority granted by the Legislature. Union Carbide v Public Service Comm 431 Mich 135, at 146, 428 N.W.2d 322. Moreover, this Court explained in Union Carbide, supra at 151, 428 N.W.2d 322, quoting Mason Co. Civic Research Council v. Mason Co, 343 Mich 313, 326-327, 72 N.W.2d 292 (1955): "The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist." Furthermore, Mich Const 1963, art 10, Sec. 2 provides "Private property shall not be taken for public use without just compensation therefor being first made or secured in a manner prescribed by law." The Fifth Amendment of the United States Constitution similarly provides that "the government may not take private property unless it is done for a public use and with just compensation." "[S]haring this grid information to better assist interested non-utility market participants" as proposed by the PFD violates these constitutional protections. See additionally Missouri ex rel Southwestern Bell Telephone Co v. Public Service Comm of Missouri, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); Federal Power Comm v. Natural Gas Pipeline, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942) Duquesne Light Co v. Barasch, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). See also Northern Michigan Water Co v. Public Service Comm, 381 Mich 340; 161 NW2d 584 (1968); Consumers Power Co v. Public Service Comm, 415 Mich 134; 327 NW2d 875 (1982); ABATE v. Public Service Comm, 430 Mich 33; 420 NW2d 81 (1988).

> are more mature than others. This PFD believes that most of the pre-exiting pilots are generally well-developed, and the utility should be able to present a permanent proposal for as many of the currently existing EV pilots as possible. Nevertheless, to address DTE's concerns, this PFD recommends that if the Company has cogent reasons that certain pilots are not sufficiently developed for final proposals, then it can so state in its next rate case and the Commission may consider setting another timeline to address final proposals for those specific pilots.
>
> DTE also objected to including a cost-benefit analysis asserting that doing so would end its ability to transition the pilots to permanent offerings. This PFD stresses that the Commission should have cost-benefit analysis to assist in evaluating the merits of proposals relative to their costs. This PFD notes that to the extent that there may be disagreement about the approach to use to measure costs and benefits, such issues can be further explored ad resolved in the next case. [PFD, p 587.]

The Company agrees in part that it propose a permanent charging Forward program, but will not be able to file a "final plan" as Staff suggested (Freeman, 8T 5545) because various elements of Charging Forward are at different levels of maturity and the EV market continues to evolve quickly. Therefore, the Company proposes to begin introducing permanent offerings, as applicable, starting with its next rate case. The Company also does not agree with the indicated expectation for a cost-benefit analysis because there is not yet alignment on the approach and requiring it would unnecessarily end the Company's ability to transition relevant Charging Forward elements to permanent offerings. The Company also disagrees with proposals by MNSC (Jester, 8T 3765) and MEIBC/IEI (Sherman, 8T 4380-4381) to determine the net effects of EV adoption and charging. These proposals are infeasible because they assume that the Company has access to information that instead is not available (Burns, 7T 2506-2510).

2. Residential Battery Pilot

The Company proposes a customer-sited behind-the-meter residential battery pilot for up to 500 residential customers. At full enrollment, the batteries would provide 5 megawatts (MW) of stored energy (10 kW per customer). 250 income-eligible participants would be offered a free battery system and 250 participants would pay a monthly subscription fee to have access to use the stored battery energy in the event of an outage. Outside of outage events, DTE Electric would have

access to use the battery to derive key learnings to determine the best path forward for residential battery storage (Burns, 7T 2484). See also Exhibit A-12, Schedule B5.10.1 for a high-level summary of how Residential Batteries meets the requirements for a pilot as provided in the February 4, 2021 Order in Case No. U-20645).

Mr. Burns further explained and supported the pilot with regard to Market Overview & Role of Utility (7T 2485-2486), Pilot Design (7T 2486-2492), and Estimated Costs and Proposed Treatment (7T 2492-2494). The Company requests to recover capital costs of $1.1 million for the 22-month bridge period and $3.1 million for the projected test year, as well as $0.2 million of O&M costs for the projected test year (Burns, 7T 2492; Exhibit A-12, Schedule B5.10, line 11, columns (e), and (f)).

The pilot's costs exceed its revenues (test year subscription revenue is estimated to be approximately $12,000), but the economics might improve in the future as battery costs are expected to continue to decline. The pilot should be approved despite the costs outweighing the revenues because the pilot seeks important new learnings regarding the ability of storage to participate in wholesale markets under FERC Order 2222, and this will also inform any potential future program design (Burns, 7T 2493). Mr. Burns further explained:

> [I]n response to FERC Order 2222, the Company may see the introduction and growth of aggregated energy storage resources on its distribution system. In this environment, the Company's ability to track and potentially control associated electricity flows, especially during times of system distress, will be critical to the continued safe operation of the distribution system. The pilot proposed here will allow the Company to test and better understand the technical and operational needs and considerations of aggregated energy storage on its distribution system, including aggregated storage which may respond to wholesale market signals. The learnings driven through this pilot should better prepare the Company for the implementation of FERC Order 2222 and ensure it is able to safely operate its distribution system in this future environment. [Burns, 7T 2493-2494.]

The income-eligible portion of the proposed pilot appears to have overwhelming support, but the pilot otherwise did not receive broad support as currently structured. The PFD agrees with

the intervening parties and states:

> This PFD recommends rejecting the residential battery pilot as currently proposed by DTE and disallowing all associated expenses; indeed, the various concerns raised by the intervening parties have substantial merit, and they touch upon nearly every aspect of the pilot. This PFD notes that the Commission recently rejected a similar home battery pilot proposed by Consumers Energy in case U-20963 expressing concerns that the Consumers Energy pilot was limited to back-up power, failed to explore the full range of benefits that batteries can provide, and raised questions about the necessity of utility ownership of BTM batteries. DTE's current home battery proposal suffers from those same shortcomings. [PFD, p 593. Footnote omitted.]

DTE Electric maintains that this is a small, properly-focused pilot, and the purpose of a pilot is to provide utility learnings, not advance third-party interests. Company ownership of the battery systems is the optimal structure for a residential storage pilot due to (1) the ability to achieve critical circuit level concentration, (2) current market dynamics, and (3) safety considerations (Burns, 7T 2524-2526). More specifically:

Company-owned battery systems will support achieving critical circuit level concentration to function as a grid asset and capture associated learnings. Company ownership of multiple battery systems is the most efficient and effective way to achieve the level of concentration that would allow the Company's Systems Operations Center (SOC) the ability to impact circuit performance by using the battery systems. Company ownership will also enable key learnings, which include the ability to test concentrated storage's impact on the firm rating of a circuit during a peak event, and how the outflow of energy from sited storage onto the grid might impact items such as volt/volt-amps reactive (VAR) and frequency (Burns, 7T 2525-2526).[102]

[102] See also *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public*

The current market is nascent and adoption to date is skewed towards higher-income segments. A utility-owned battery pilot will help with equity, especially the portion offered for free to income-eligible customers on targeted circuits (Burns, 7T 2526).

From a safety perspective, alternative ownership models, specifically BYOD, have the potential to exacerbate system issues during high-demand events by allowing customers to control charging/discharging onto the grid. Company ownership of the battery systems mitigates this risk by creating a layer of monitoring and controls to prevent battery assets from becoming harmful to the grid (Burns, 7T 2526).

For all of these reasons, the Company requests that the Commission approve the pilot as proposed and reject the PFD's recommendation.

V. RATE OF RETURN

The PFD recommends a weighted, after-tax overall rate of return of 5.42% (PFD, pp 457, 729 and Appendix D). DTE Electric takes exception regarding this and the PFD's 9.9% return on equity (ROE). (PFD, pp 457, 729). The Company requests a weighted, after-tax 5.56% overall rate of return (Vangilder, 7T 2809; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed below.

H. Return on Common Equity

The PFD "recommends that the Commission should keep DTE's authorized ROE at 9.90%" (PFD, p 456). The Commission should instead adopt DTE Electric witness Dr. Villadsen's

Service Comm, 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

recommendation that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.25%. This is the midpoint of Dr. Villadsen's range of 9.9% to 10.6% and is conservative because DTE Electric has greater-than-average risk (Villadsen, 7T 1309-1310, 1355-1356, 1398).

The PFD also found "that the ROE's recommended by Staff (9.6%), the Attorney General (9.5%), and ABATE (9.4%) are reasonable and supported by the record" (PFD, p 455). DTE Electric disagrees, but notes that as indicated above, the PFD does not adopt any of those recommendations. Thus, this finding may be moot (at least for purposes of these exceptions), but it is discussed for context and completeness.

The Commission has also emphasized, and the PFD recognized (at pp 455-56), that proposals to radically reduce a utility's ROE (as Staff, the AG, and ABATE suggest) are neither realistic nor helpful to the Commission (September 13, 2018 Order in Case No. U-18999, p 52). The Commission has repeated its recent request for parties "to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions." *Id*, quoting March 29, 2018 Order in Case No. U-18322, p 44. Here, the underlying economic conditions support an increase in DTE Electric's ROE, as Dr. Villadsen recommended, rather than any decrease.

The PFD rejected the Staff's, AG's and ABATE's recommendations based in part on Dr. Villadsen's testimony emphasizing recent events including rising interest rates and inflation (which also supports a ROE increase):

> In light of the evidence provided by Intervenors, it is evident that interest rates have increased in recent months. This is supported by, for example, when the Federal Open Markets Committee in March raised interest rates by 25 basis points, and then again by 50 basis points in May 2022. This was the first "tightening" since December

> 19, 2018. This year, more tightening is anticipated, with the funds rate projected to reach 3.0 percent by late 2023. Further, as acknowledged by Mr. Walters, the Russian army invaded Ukraine on February 24, 2022. The ongoing war resulted in increased uncertainty regarding oil and agricultural prices. Consistent with these events, Blue Chip Economic Indicators (BCEI) now project inflation at 6 percent this year, up from 4.2 percent just a month ago. Further, forecasts for U.S. GDP growth have declined, where first quarter of 2022 reported *negative* GDP growth of 1.4 percent, raising questions of a "recession" for many consumers. [PFD, p 455, quoting Villadsen, 7T 1428-1429. Emphasis in original; footnotes omitted.]

The PFD, however, disagreed with DTE Electric (at p 455, n 1327) that the Commission might further take notice of more recent events including a 75-basis point interest rate increase in June 2022, and another 75-basis point interest rate increase in July 2022. The PFD reasoned that the information is not part of the evidentiary record, which is literally true, but neglects that the Commission can take official notice under R 792.10428 where, as here, these well-known and relevant instances of further rate increases are not subject to dispute.

The Commission should take further notice that there was another 75-basis point interest rate increase on September 21, 2022. Thus, there have been five consecutive interest rate hikes (so far) this year. The AG's Initial Brief, p 88, also acknowledges that "more recently inflation has become a concern and to combat that, the Federal Reserve has pledged to increase short term interest rates and has taken actions expected to increase long term interest rates."

The PFD's suggestion that the Commission cannot monitor and consider market factors also neglects that in DTE Electric's last general rate case, after the Commission set DTE Electric's currently-authorized ROE at 9.9%, the Commission stated:

> The Commission will continue to monitor a variety of market factors in future applications, including market reactions to recent events and measures of volatility and uncertainty, as well as measures of investor confidence, and the utility's risk profile. [May 8, 2020 Order in Case No. U-20561, pp 176-177.]

The Commission similarly stated in DTE Electric's previous rate case that it "will continue to monitor a variety of market factors in future applications to gauge whether volatility and

uncertainty continue to be prevalent issues that merit more consideration in setting the ROE" (May 2, 2019 Order in Case No. U-20162, pp 67-68). In Case No. U-20940 (DTE Gas's most recent general rate case), the Commission "agree[d] with DTE Gas that because of the ongoing COVID-19 pandemic, there may be continued uncertainty in the capital markets that may affect the cost of capital" (December 9, 2021 Order in Case No. U-20940, p 92). See also the December 17, 2020 Order in Case No. U-20697, pp 165-166, where the Commission stated that it "will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE").

Dr. Villadsen further explained that the determination of DTE Electric's ROE takes place during the ongoing impacts from the COVID-19 pandemic, which has led to unprecedented low Treasury bond yields and shifts in the relative risks of industries. Since Case No. U-20561 (where the Commission set DTE Electric's ROE at 9.9%), the systemic risk of utilities (measured by beta) has increased, as has the MRP, while the risk-free rate as measured by government bonds had decreased up until the filing. The dramatic increase in beta (0.91% as of June 30, 2021, as compared to approximately 0.6% in Case No. U-20561) combined with an increase in the MRP has resulted in a substantially higher utility-specific risk premium (Villadsen, 7T 1308-1311, 1329-1330, 1335).

Dr. Villadsen further explained, as indicated in part above, that interest rates are expected to continue increasing, and it is the expected risk-free rate over the period when rates will be in effect that is needed to estimate DTE Electric's ROE (7T 1320-1322). The VIX and SKEW index indicate that investors expect volatility to continue for at least a year (Villadsen, 7T 1322-1324). It is reasonable to expect that the current MRP will remain elevated compared to historical levels, especially given the uncertainty related to the extent of economic and financial impacts from COVID-19 (Villadsen, 7T 1328). Rising inflation has also introduced new uncertainties to the

capital markets, and points to an increase in the return that investors require to hold risky assets (Villadsen, 7T 1331-1335).

This is also a particularly inopportune time to weaken the Company's credit metrics due to the Company's need for capital spending, as discussed above. The Commission has declined to follow such arguments in past cases. (January 31, 2017 Order in Case No. U-18014, pp 65-66; December 11, 2015 Order in Case No. U-17767, pp 54-55).

The PFD's evidentiary discussion (PFD, 445-54) is also incomplete adopting certain criticisms of Dr. Villadsen's presentation suggested by other parties, without analyzing those parties' presentations or evaluating them in complete context, on the way to finding that those parties' proposed ROE's are both reasonable and supported (which is improper) and rejected (which is ultimately the correct result). Therefore, DTE Electric presents the following additional discussion of the evidentiary record.

Staff recommended a 9.6% ROE (Ufolla, 8T 5085-5100-5101). The AG recommended 9.5% (Coppola, 8T 4818, 4846). ABATE recommended 9.1% (Walters, 8T 3046-3047). MEC/CUB recommended 8.8% (Garret, 8T 3868-3869).[103] Dr. Villadsen explained that the Staff, AG, ABATE and MEC/CUB all make recommendations which are too low in today's financial environment where it is imperative to analyze up-to-date data. For example, the AG, ABATE and MEC/CUB's recommendations are below the average ROE for "Vertically Integrated" electric utilities from 2021 through May 20, 2022. As such, these recommendations are not even within the range of reasonableness in the current environment of high inflation and rising interest rates. The ROE recommendations are also downward biased due to analytical errors and fail to take into

[103] Walmart witness Perry disagreed with Dr. Villadsen's recommendation, but did not offer a specific proposal (Perry, 8T 4125).

account the interaction of capital structure (financial risk) and ROE. The changes in the capital markets (rising interest rates, high inflation, and increased market volatility), the challenging Michigan economic environment, and the differences in financial risk for DTE Electric as compared to sample companies, justify an increase in DTE Electric's ROE (Villadsen, 7T 1399-1409).

Dr. Villadsen selected a sample of 27 regulated electric utility companies, 8 natural gas distribution companies, and 8 water utilities. The sample of natural gas and water utilities are similar to DTE Electric because they are rate regulated by state utility commissions, serve customers through a network of assets, and are capital intensive (Villadsen, 7T 1314, 1318, 1336-1342). Staff, the AG, ABATE and MEC/CUB criticized Dr. Villadsen's inclusion of natural gas and water utilities. She responded by further explaining the appropriateness of her proxy group, and that the issue is ultimately moot because her ROE recommendation is fully supported by the results from her sample of electric utilities (Villadsen, 7T 1408-1409).

Dr. Villadsen estimated the ROE for each company in her sample using two versions of both the Capital Asset Pricing Model (CAPM),[104] and Discounted Cash Flow (DCF) approaches, as well as a risk premium model. She also considered differences in financial risk inherent in each company's capital structure (the higher the debt-to-equity ratio, the higher the financial risk, and the higher the cost of equity) using (1) the overall cost of capital approach, and (2) the Hamada approach. In recognition of the Commission's past decision to not rely on the overall cost of capital approach, however, her CAPM / ECAPM recommended range is based on the Hamada approach. This approach cannot be applied to the DCF model (Villadsen, 7T 1342).

[104] The CAPM is a risk positioning risk positioning approach. Dr. Villadsen also used the Empirical CAPM (ECAPM) (7T 1343).

Her rebuttal testimony further discussed well-established financial principles, and responded to criticisms and apparent misunderstandings by Staff, the AG, ABATE and MEC/CUB (now echoed by the PFD at pp 446-47) regarding the impact of financial leverage on the cost of equity (Villadsen, 7T 1429-1441). By failing to account for fundamental financial principles, the Staff, AG, ABATE, and MEC/CUB's ROE estimates are downward biased by at least 150 basis points (Villadsen, 7T 1440-1443).

1. CAPM and ECAPM Estimates

Dr. Villadsen developed ROE estimates based on the CAPM and an empirical approximation to the CAPM (ECAPM). The CAPM is based on the idea that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk using (a) a risk-free rate, (b) beta,[105] and (c) a market risk premium (MRP). (Villadsen, 7T 1343-1344).

Dr. Villadsen further explained that empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta. Low-beta stocks tend to have higher risk premiums than predicted by the CAPM, whereas high-beta stocks tend to have lower risk premiums than predicted by the CAPM. Dr. Villadsen adjusted by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests (Villadsen, 7T 1343-1344).

As a proxy for the risk-free interest rate, Dr. Villadsen used the average yield on the 10-year U.S. Treasury bond forecasted by *Blue Chip Economic Indicators* to be in effect for 2022 - 2024,

[105]Beta is a measure of the risks that cannot be eliminated by diversification. It measures the "systematic" risk of a stock – the extent to which the stock's value fluctuates more or less than the market fluctuates (Villadsen, 7T 1343).

and adjusted it upward by 50 bps, which is her estimate of the representative maturity premium for the 20-year over the 10-year Treasury bond, for a risk-free rate of 2.73%. Her Scenario 1 combines the 2.73% risk-free rate with the 7.25% historical average MRP. Her Scenario II combines the 2.73% risk-free rate with Bloomberg's forecasted MRP (over the 20-year Treasury bond yield) of 7.89% (7T 1345). She did not make a yield spread adjustment as she has done in the past (Villadsen, 7T 1345, n 80). As of the time of rebuttal, the actual yield on the risk-free rate increased to 3.07 percent (Villadsen 7T 1405), which was higher than the rate used in Witness Villadsen's Direct Testimony.

The Electric Utility Sample's results are consistent with a cost-of-equity range of 10.3% to 11.4% (ignoring the financial risk adjustment that the Commission criticized in the past). Rounding to the nearest ¼ percent (which is Dr. Villadsen's practice), the CAPM / ECAPM indicates a ROE range of 10.25% to 11.5% for the Electric Utility Sample before any DTE Electric risks are considered. The Natural Gas and Water Utility Sample has a similar ROE range of 10.25% to 11.25% (Villadsen, 7T 1346-1347).

Staff computed a ROE of 9.08% using an historical CAPM, and 10.69% using a projected CAPM (Ufolla, 8T 5094-5095). Dr. Villadsen agreed with the use of multiple CAPM scenarios, but explained that Staff's historic CAPM was downward biased because it used a MRP of 7.25% from 2020, instead of 7.46% from 2021, when this updated data was available and should have been used. Also, Staff used a 2.86% risk-free rate, but as of June 1, 2022, the 30-year yield was 3.16%. Using the current risk-free rate (3.16%) and MRP (7.46%) increases Staff's historical CAPM by 51 basis points (from 9.08% to 9.59%) and Staff's average CAPM estimate becomes 10.14%, which is very close to DTE Electric's requested ROE (Villadsen, 7T 1399, 1418-1419).

AG witness Coppola similarly used an outdated MRP. Simply using updated data from 2021 increases his CAPM estimate from 9.39% to 9.56% (Villadsen, 7T 1399, 1419).

Dr. Villadsen disagreed with ABATE witness Walters' beta analysis, emphasizing that it is imperative that betas reflect the best estimate of systemic risk. Mr. Walters' use of the historic average of betas since 2014 lacks relevance and downward biases his CAPM results by 0.85% to 1.6%. He also neglected to account for DTE Electric's capital structure, even though he relied on a document clearly showing that it is fundamental to do so (Villadsen, 7T 1419-1420).

Dr. Villadsen further emphasized that consistency is important. For example, MEC/CUB witness Garrett used the MRP from Duff & Phelps, yet ignored that same source's corresponding risk free rate. This inconsistency alone downward biased his CAPM estimate by 26 basis points. His analysis is also flawed in using backward-looking selective data, and not considering forward looking MRPs, which is significant because DTE Electric's ROE will be in effect going forward (Villadsen, 7T 1400, 1420).

Staff (Ufolla, 8T 5097) and ABATE (Walters, 8T 3108) suggested that it is inappropriate to both use adjusted beta estimates and apply the ECAPM. Dr. Villadsen explained that these are two fundamentally different and complementary adjustments, with no redundancy. The adjustment to beta corrects the estimate of the relative risk of the company. The ECAPM adjusts the risk-return tradeoff. Both adjustments are necessary to produce the most accurate forward-looking estimate of the required return on equity. Thus, there is no merit in suggestions that using both adjustments leads to biased results, as further reflected by the ECAPM resulting in a ROE estimate that is close to the traditional CAPM (Villadsen, 7T 1421-1427).

MEC/CUB suggested that Dr. Villadsen's 7.89% equity risk premium is too high as compared to other sources (Garrett, 8T 3922). Dr. Villadsen disagreed, noting that it is within the

range used by the AG and ABATE. Capital market conditions also indicate that the MRP is likely to remain elevated due to rising inflation and interest rates (Villadsen, 7T 1328, 1427-1428).

MEC/CUB also suggested that Dr. Villadsen's risk-free rate is over estimated (Garrett, 8T 3928). Dr. Villadsen disagreed, emphasizing recent events including rising interest rates and inflation:

> In light of the evidence provided by Intervenors, it is evident that interest rates have increased in recent months. This is supported by, for example, when the Federal Open Markets Committee in March raised interest rates by 25 basis points, and then again by 50 basis points in May 2022. [The Commission might further take notice of a 75 basis point interest rate increase in June 2022.] This was the first "tightening" since December 19, 2018. This year, more tightening is anticipated, with the funds rate projected to reach 3.0 percent by late 2023. Further, as acknowledged by Mr. Walters, the Russian army invaded Ukraine on February 24, 2022. The ongoing war resulted in increased uncertainty regarding oil and agricultural prices. Consistent with these events, Blue Chip Economic Indicators (BCEI) now project inflation at 6 percent this year, up from 4.2 percent just a month ago. Further, forecasts for U.S. GDP growth have declined, where first quarter of 2022 reported *negative* GDP growth of 1.4 percent, raising questions of a "recession" for many consumers. [Villadsen, 7T 1428-1429. Emphasis in original; footnotes omitted.]

AG witness Coppola also acknowledged that "in late 2021 and early 2022, inflation has become a concern" (8T 4837) and "the current state of the economy and financial markets has increased business risk" (8T 4844).

2. DCF Estimates

Dr. Villadsen explained that the DCF model assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The single-stage DCF model assumes that the stream of future dividends will grow at a constant rate into perpetuity. The multi-stage DCF model accommodates different dividend growth rates at different points in time (Villadsen, 7T 1347-1348).

Dr. Villadsen calculated both the single-stage and multi-stage DCF using growth rates from *Value Line* and *IBES*, as well as GDP forecasts from *Blue Chip Economic Indicators* for the multi-

stage DCF. The corresponding ROE estimates range from 8.7% to 10.4% for the Electric Utility Sample, and 8.0% to 11.1% for the Natural Gas and Water Sample. Dr. Villadsen viewed the multi-stage results (8.7% and 8.0%) as unrepresentative, however, because they fail to include the very-high near-term GDP growth, and are out of line with other results. Therefore, she considered the range determined by the upper half of the estimation results representative (*i.e.*, and again rounding to the nearest ¼ percent, 9.5% to 10.5% for the Electric Utility Sample, and 9.5% to 11.0% for the Natural Gas and Water Sample, before any DTE Electric risks are considered) (Villadsen, 7T 1349).

Dr. Villadsen's rebuttal responded to other witnesses' criticisms and their implementation of DCF models (Villadsen, 7T 1412-1417). For example, MEC/CUB witness Garrett implemented a quarterly version of the single-stage DCF model using a 2021 nominal GDP growth, which is meaningless as a growth rate for electric utilities. It fails to consider any unique features of the industry, and downward biases his DCF estimate by about 2% (Villadsen, 7T 1399, 1412-1413).

ABATE's sustainable growth method is not properly implemented for at least three reasons. First, it relies on only one source for its growth rates. Second, an input to the model, the expected return on equity, averages 10.83%, but Mr. Walters calculated a ROE of 8.58%. This inconsistency in inputs and output proves that the recommendation should be disregarded. Third, the model does not account for companies in ABATE's sample engaging in share buybacks, which downward biases the estimated ROE (Villadsen, 7T 1400, 1413-1414).

MEC/CUB witness Garrett indicated that Dr. Villadsen used an 8.3% long term growth rate, which he claims is too high (8T 3910). Dr. Villadsen explained that this was just the long-term growth rate from one company in her proxy group. She used the *average* across the sample in her proxy group, which was 5.5% (Villadsen, 7T 1414-1415).

Mr. Garrett further suggested that the analysts' long-term growth rate projections, which Dr. Villadsen used, are unreliable to provide fair indicators of utility growth over a long horizon (8T 3906). This criticism is incorrect because most estimates of growth rates in DCF models rely on analysts' forecasted growth rates (Villadsen, 7T 1415-1417).

3. Risk Premium Estimate

In the risk premium model, the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. The risk premium model produces a range of 9.8% to 9.9% for an average ROE for the average electric utility. This range is consistent with the estimates from the lower end of the CAPM and the middle range of the DCF model for the Electric Utility Sample (Villadsen, 7T 1350-1351).

4. DTE Electric's Return on Equity in Relation to Risk

As indicated at the beginning of this ROE discussion, the PFD appropriately recognized (in part) the risks that DTE Electric faces, and that they at least compel rejection of any recommendation to lower the Company's ROE. On the other hand, the PFD (at pp 449-54) suggests that DTE Electric is not risky. DTE Electric disagrees because, as Dr. Villadsen explained, in the current environment of market uncertainty, DTE Electric's lack of a revenue decoupling mechanism or a fixed variable pricing policy places it at increased risk of under-recovering its cost of service relative to some companies in Dr. Villadsen's sample that benefit from such mechanisms. Moreover, and in addition to ongoing uncertainty in the capital markets discussed above, DTE Electric faces increased risk of under-recovery because its service territory includes the greater Detroit area, which continues to be economically challenged. DTE Electric also has an asymmetrical risk (downside risk with no corresponding upside) due to the responsibilities of

owning and safely operating a nuclear power plant. Therefore, DTE Electric has a higher-than-average business risk relative to companies in Dr. Villadsen's sample (Villadsen, 7T 1311, 1352-1355).

5. Summary and Recommendations Regarding DTE Electric's Cost of Equity

The Commission should increase DTE Electric's ROE to 10.25% because the current cost of equity is higher than it was when the Commission set DTE Electric's ROE at 9.9% in Case No. U-20561. The average of the low and high estimates from Dr. Villadsen's DCF, CAPM and Risk Premium models results in a range of 9.9% to 10.6%, the midpoint of which (rounded to the nearest ¼ percent) is 10.25%. This is a conservative estimate for DTE Electric's ROE because DTE Electric has higher-than-average risk compared to the sample companies, so it would be reasonable to place DTE Electric in the upper half of the estimates (Villadsen, 7T 1355-1356). Increasing DTE Electric's ROE is also appropriate (and proposals to lower DTE Electric's ROE are also inappropriate) in today's financial environment of high inflation, rising interest rates, and market volatility (Villadsen, 7T 1399, 1428-1429).

Therefore, the PFD's recommendation to maintain DTE Electric's ROE at 9.9% is impropriate. The Commission should instead increase DTE Electric's ROE to 10.25%.

VI. DTE ELECTRIC'S ADJUSTED NET OPERATING INCOME SHOULD BE ADOPTED.

DTE Electric projected its Total Electric Adjusted Net Operating Income (NOI) to be approximately $912.8 million (as revised in DTE Electric's briefs). The PFD recommends $1,002,341,000 (PFD, p 540 and Appendix C). DTE Electric takes exception to this and other matters as discussed below.

A. RIA credit count

The Commission previously reduced the Residential Income Assistance (RIA) [106] enrollment level from 60,000 to 43,000 customers, and retained the Low Income Assistance (LIA) program enrollment at 32,000 customers. The Commission also authorized the Company to track enrollments up to the projected enrollment of 60,000 for RIA and 50,000 for LIA, to be booked as a regulatory asset (May 8, 2020 Order in Case No. U-20561, p 239).

Staff and the Company agree that the difference in projected and actual low-income-credit customer counts should be recorded as a regulatory asset/liability. Accordingly, the PFD recommends that the Commission permit deferred accounting balances to be presented and rate treatment determined in rate cases rather than through a biennial reconciliation (PFD, pp 467, 601. See also Uzenski, 7T 2787-2788; Staff Initial Brief, pp 125-26).

The Company forecasts RIA enrollment of 61,745 customers in the projected test year. RIA enrollment as of June 2021 at 64,000 electric low-income customers. All eligible customers seeking the RIA credit are granted enrollment. The numbers continue to trend upward, so it is reasonable to expect that enrollments will remain at or above the 60,000 level (Johnson, 5T 817).

The PFD agreed with Staff's assertion that the number of customers receiving the RIA credit cannot be discerned (Braunschweig, 8T 5274) (However, as explained further below, in response to Staff's concerns, the Company testimony provided additional evidence in rebuttal testimony on the then current number of customers receiving the RIA credit, and as well as actual numbers for previous years.) Ms. Johnson explained that Staff's proposal falls far short of the demonstrated need for energy assistance. Reducing that assistance as Staff proposed would be a step backwards from the progress that has been made and that continues to be needed in identifying and helping

[106] The RIA provision provides a $7.50 per month credit for qualifying customers, which offsets the current $7.50 monthly service charge.

struggling households. The Commission should adopt the Company's forecast of 61,745 RIA enrollments and retain the current practice of pairing LIA enrollments with LSP, along with the Company's discretion to enroll non-LSP households when space is available (Johnson, 5T 833-834).

Staff also proposed a $2,587,050 increase to present sales revenue based on the suggestion that there was a discrepancy regarding RIA enrollments among Company witness Johnson's direct testimony, an audit response, and the Company's proposed rate design (Braunschweig, 8T 5274-5277). The PFD found that Staff's projection and adjustment should be adopted, indicating more confidence in Staff's numbers (PFD, pp 465-67).

The Company disagrees because witness Johnson characterized current enrollment as of June 2021. The audit response and Part III filing relied on by Staff reflect historic multi-year average figures. The Company's rate design forecasts what the Company estimates enrollments will be during the projected test year based on historic actuals and known and measurable changes, consistent with how billing determinants are generally designed. Thus, there is no inconsistency or conflict in the three numbers reflecting three different time periods and approaches. Staff's suggestion that RIA enrollments are trending downward is also contrary to the actual trend of rising RIA enrollments over the last 51 months, and particularly the last two years, with the Company issuing over 73,000 RIA bill credits in March 2022. The Company's proposal of 61,745 monthly average RIA enrollments is a reasonable forecast given historical test year information, and is corroborated with 2021 and partial 2022 data (Willis, 6T 975-976).

Regarding evidence presented by Company Witness Willis showing the trends of rising RIA enrollments, the PFD implies that the data was not sufficiently more reliable than Staff's historical evaluation. , (PFD p 466) The Company takes exception to the claim made by the PFD that the

Company "did not provide the actual data points" simply because the data was presented using a line graph. The line graph included in Mr. Willis's rebuttal testimony was clearly stated to include monthly RIA enrollments since January 2018 based on actual bill credits, and it includes axis labels so one can discern what the data points represent and how they changed through time (Willis, 6T 976). Contrary to what the PFD seems to suggest, the evidence presented by the Company exceeds the requisite burden and the data should not be disregarded by the Commission simply because it was presented in a line graph. Mr. Willis also states in his rebuttal testimony the data presented consists of monthly RIA enrollments since January 2018. Thus, it is clear the data presented consists only of RIA data, as opposed to some combination of RIA and LIA data. Notably, the PFD states, "[w]hile Staff identified a 2020 value of 32,688 RIA enrollments, it appears that many if not all of the monthly values Mr. Willis used in his graph are above that value." This is true because the actual data over the time-period presented in Mr. Willis's testimony shows RIA enrollments have been rising – a trend which is particularly consistent in the last 2+ years (Willis, 6T 976). Finally, the PFD claims another reason a trend cannot be discerned from the data is because the 2018 data reflects an IT system issue, with zero enrollments shown for one month. However, the fact there was a dip in 2018 driven by IT system issues in no way discredits the evidence showing after that point enrollments increased. Therefore, the Commission should reject Staff's proposal, and instead adopt the Company's proposed forecast of 61,745 RIA credits and resulting revenues.

B. Operating and Maintenance (O&M) Expenses

DTE Electric projects total O&M of $1,264.0 million in the test period (as revised by DTE Electric's briefs; see DTE Electric's Initial Brief, Attachment A, page 3).

1. Distribution (Exhibit A-13, Schedule C5, line 6; Schedule C5.6)

DTE Electric's Initial Brief, p 181, explained and supported $318.0 million of Distribution Operations' O&M expenses for the projected test period.

i. O&M Restoration Costs

Staff proposed that O&M restoration costs remain based on a five-year average rather than the Company's proposed three-year average, which would increase the Company's O&M projection by $14.777 million. The PFD states that "[f]or the reasons explained above, this PFD concludes that the five-year average should be used" (PFD, p 471).

As discussed above regarding emergent capital expenditures, the Company believes that a three-year average better reflects current conditions. If the Commission adopts a five-year average for emergent capital, however, then the same method should apply to O&M restoration costs, resulting in a $14.777 million increase as Staff proposed and the PFD effectively recommends (Pfeuffer, 4T 505).

ii. Tree Trimming, and Surge Program Regulatory Asset Return

The Company does not take exception to the PFD's tree trimming discussion (PFD, pp 472-74), but does take exception to the PFD's later discussion about surge program regulatory asset return (PFD, pp 535-40). For general context, the Company proposes $103.9 million of 2023 base O&M funding, surge funding of $67.0 million in 2023, and $52.7 million in 2024. The Company is *targeting* to complete the surge program by the end of 2024, which is one year earlier than previously proposed in Case Nos. U-20162 and U-20561, due to the Company's additional funding as discussed in the Company's application in Case No. U- 21128 (See generally, DTE Electric's Initial Brief, pp 182-89).

The Company proposes to defer surge costs up to $248.8 million above base rates from 2021 through 2024 (Exhibit A-22 Revised, Schedule L1, page 1, line 12, columns c-f). The Commission previously approved, in Case No. U-20162 and Case No, U-20561, regulatory asset treatment for the incremental costs of tree trimming above base rates through 2022 totaling $246.1 million, $156.9 million of which was deferred in 2019 through June 2021, and has been securitized pursuant to the June 23, 2021 Order in Case No. U-21015. Securitization remains appropriate to recognize the long-term nature of the program. Recovery over a longer period provides a better matching of costs with anticipated savings, minimizing the cost impact to customers (Hartwick, 7T 2322-2323).

In Case No. U-20162, the Commission authorized a return on the tree trim regulatory asset at the Company's short-term debt rate, reasoning that the regulatory asset treatment of surge costs was temporary in light of the Company's contemplated securitization filing (May 2, 2019 Order in Case No. U-20162, p 80). [107] This treatment was continued in Case No. U-20561.

In contrast to this treatment, in the Company's securitization case, Case No. U-21015, the Commission considered the regulatory asset to have been financed with permanent capital and specified that proceeds of the securitization should be used for the repayment of long-term debt and equity. Consistent with that financing order, any future tree-trim surge regulatory asset amounts should be treated as being financed with permanent long-term debt and equity, and receive the respective return, until the Company can execute a securitization financing for these amounts (Lepczyk, 7T 1294-1295; Crozier, 7T 1298-1299, 2350). [108] Exhibit A-11, Schedule A1.1 identifies

[107] Securitization is the financing of a discrete asset or group of assets by a utility with securities whose credit quality is separated from that of the utility, in order to achieve higher credit ratings and lower financing costs.

[108] Similar to the recent securitization filing in Case No. U-21015, the Company will likely file for securitization authorization once the expense balance reaches approximately $150 million, which the Company anticipates will occur in late 2023 (Crozier, 7T 2356-2357).

the $7.0 million return on the tree trim surge regulatory asset for the projected test period (Vangilder, 7T 2813).

Staff proposed a $4,833,000 decrease by instead applying the currently-approved 2.73% short-term debt rate. The AG proposed a $5,626,000 reduction by using a short-term debt rate of 1.74%. The PFD agreed with Staff and the AG recommending that the Commission authorize a return of $1,395,000 [109] based on the short-term debt rate of 1.74% (PFD, pp 539-40). In turn, the PFD reasoned that the circumstances had not changed significantly since the Commission approved the surge in Case No. U-20162.

The Company disagrees because after Case No. U-20162, the Commission decided Case No. U-21015 in which it considered the regulatory asset to have been financed with permanent capital and specified that proceeds of the securitization should be used for the repayment of long-term debt and equity. The same circumstances exist in this case, so consistent with the U-21015 financing order, any future tree trim surge regulatory asset amounts should be treated as being financed with permanent long-term debt and equity capital, and receive the respective return (Lepczyk, 7T 1298-1299).

iii. Community Lighting (Exhibit A-13, Schedule C5.6, lines 8 and 22)

Mr. Bellini supported DTE Electric's Community Lighting O&M expenses for 2020 through the projected period ending October 31, 2023 (7T 1710). O&M expenses for street lighting and signal systems (reflected on Exhibit A-13, Schedule B5.6, lines 8 and 22) are held steady at the 2020 historical level of $3.8 million, adjusted only for inflation. Mr. Bellini further explained that the Company implemented an LED washing and group relamping preventative maintenance program in 2018, based on studies that identified a need to periodically wash LEDs to ensure that

[109] This amount is not consistent with Appendix A.1.

their lumen output provides acceptable lighting for customer safety and security design requirements (7T 1717-1718). Mr. Bellini supported these expenses as reasonable, based on his analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power, and plans for maintaining and/or improving customer service (7T 1720).

Staff proposed a $241,596 O&M disallowance because the Company did not spend the full amount in 2021. As explained by the Company on pages 111-113 above, Staff calculated its proposed disallowance percentage of 5.87% by comparing actual 2021 Capital expenditures vs proposed 2021 Capital expenditures, and then applied this percentage to projected, inflation adjusted O&M spend in the test period. This analysis is flawed for two reasons. First, though the Company disagrees with Staff's methodology, to be consistent, Staff should have evaluated the Company's proposed O&M test period spend based on the Company's 2021 O&M spend vs its' 2021 O&M projected. This would have shown the Company having spent 12.8% more ($4.406M vs $3.906M) in 2021 than what was projected (Company Exhibit A-13, C5.6 p1, line 22). Staff should not have used its' Capital expenditure disallowance and applied it to the Company's projected O&M test period spend, when in fact Staff could have evaluated the Company's actual 2021 O&M expenditures vs 2021 proposed O&M expenditures. Staff referenced the Company's projected O&M spend, in which the Company used its historical 2020 YE spend. Second, Staff offered no support as to why Capital expenditures, and not O&M costs should be the basis for establishing a disallowance ratio. Staff incorrectly attempts to correlate Capital expenditures with O&M expenditures and assumes the factors resulting in the Company's 2021 Capital underspend vs 2021 projected spend should take precedent in evaluating bridge and test period O&M proposed

spend, while setting aside those factors specific to O&M that resulted in the Company spending more O&M in 2021 than what it projected (Bellini, 7T 1775-1776).

Staff responded: "It is reasonable and prudent to expect that accompanying O&M costs will be reduced if the Company underspends capital by the same percentage in future projected periods. One can reasonably assume that O&M costs will be reduced by the same percentage as the reduction in capital work" (Staff Initial Brief, pp 166-67).

The PFD agreed with Staff, stating:

> This PFD finds Staff's recommendation reasonable and concludes it should be adopted. Since DTE was projecting that it would spend both capital and O&M, it is appropriate to reduce the O&M expense allowance along with the capital expense allowance. [PFD, p 476.]

The Company disagrees, emphasizing that there is no basis for Staff's indicated assumption(s) that capital expenditures and O&M costs have some relationship(s) such that underspending in capital would somehow correspond to underspending by the same percentage in O&M (Wang, 8T 5173). Capital expenditures and O&M costs are two different things, as reflected for example by extensive separate discussions of them in the PFD and these Exceptions. Staff offered no basis for its position other than its own assumption(s), which are entirely speculative and unsupported, and therefore cannot support such a decision. [110] The Company also fully supported its O&M recovery, as indicated above. Though the Company's 2021 O&M actuals were far in excess of 2021 projected O&M spend, the Company projected no additional O&M spend and only

[110] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

seeks adjustments as a result of inflation through the bridge period and projected test year. Therefore, the PFD's recommendation should be rejected.

MI-MAUI and Ann Arbor asserted that the Company is needlessly washing lamps on an accelerated basis and out of step with IES recommended practices. The PFD agreed, explaining in part:

> This PFD finds MI MAUI and Ann Arbor's argument persuasive that DTE failed to produce its own study when requested, as shown by Exhibit MAUI-19, and thus has failed to establish that its LED washing program is reasonable and prudent. This PFD recommends that the Commission reduce cost recovery for the LED washing program by 50%, to 135,000 per year. [PFD, p 478.]

The Company disagrees because the preponderance of the evidence shows that its LED washing program is reasonable and prudent. Mr. Bellini explained that the IES study did not include the luminaire type predominately used by the Company and was not specific to the environment where the LED luminaires operate. Heavy truck traffic and salt spray are unique to a Midwest state such as Michigan, and particularly to the Company's service territory. Plainly, an LED in Phoenix, Arizona will be impacted differently from dirt depreciation than the same LED in the metro-Detroit area. The Company studied the impacts of dirt depreciation unique to the roadway conditions where the Company's luminaires operate, the results of which indicate that washing on a five-year cycle maintains a safe driving environment (Bellini, 7T 1762-1763). The PFD's characterization of Exhibit MAUI-19 is also unfounded (suggesting without explanation or support that the Company was "unwarranted" in raising a confidentiality objection) and otherwise neglects that the exhibit further supports the Company's position. Therefore, the PFD's recommendation should be rejected.

2. Customer Service (Exhibit A-13, Schedule C5, line 7; Schedule C5.7)

Mr. Sparks supported the actual and projected O&M expenses for the Customer Service organization as reasonable and necessary (7T 1616-1639; Exhibit A-13, Schedule C5.7).[111] These O&M expenses (including rate case adjustments) were $110.7 million for the 2020 historical test period and expected to increase to $133.6 million for the projected year (Sparks, 7T 1616, 1624, 1636-1639; Exhibit A-13, Schedule C5.7). The Company agrees to a $0.95 million O&M reduction as discussed below.

iv. Customer Service Representatives (CSRs)

Mr. Sparks explained that $7.9 million attributed to Customer Records and Collections Expenses is driven in part by the need for 120 additional CSRs and associated expenses, including training and development, to address more complex call types such as customers with high bills and low-income and the associated ongoing training and development needed to improve operational performance and customer satisfaction. Additional CSRs are also required to reduce the Company's average speed to answer service level in the call center. (Sparks, 7T 1637-1638). This category also includes $2.3 million for TOU Full Implementation ongoing costs that include billing exceptions ($1.3 million), digital experience ($0.5 million), and AMI support ($0.5 million) (Sparks, 7T 1638).

The AG's Initial Brief, pp 26-28, proposed a $9.7 million reduction in O&M expense, without indicating its basis. Witness Coppola suggested that it relates to the additional 120 CSRs (8T 4860-4861), but Mr. Sparks clarified that only $5.6 million relates to the incremental 120 CSRs.

[111] Customer Service has two divisions, which are (1) Operations and (2) Customer Strategy & Insight. Customer Service Operations includes Contact Center Operations, Metering, Billing & Exceptions, Revenue Management and Protection (RM&P), and Customer Service Operations Support. Customer Strategy and Insight includes Customer Service Transformation, Customer Service Analytics, Executive Consumer Affairs Center (ECAC), and Digital Experience. These organizations are responsible for billing, customer contact, and payment acceptance (Sparks, 7T 1618-1621).

The AG's proposed $9.7 million disallowance also includes an unrelated (1) $1.8 million driven by lag hire in 2020 due to the pandemic and (2) $2.3 million associated with ongoing O&M for TOU implementation (7T 1642-1643).

Mr. Coppola suggested that, because overall headcount increased from 2019 to 2020, "it does not appear that there was much if any delayed hiring" (8T 4860). Mr. Sparks explained that the change in headcount was driven by incremental CSRs hired for a new call center in Cass City during 2020, with the associated cost offset by a $3 million decrease in external call vendor spend (7T 1643).

Mr. Coppola further suggested that additional CSRs are unjustified in light of the Company's proposed digital enhancements (8T 4860). Mr. Sparks explained that the AG's proposal conflates different things. Digital enhancements reduce the *volume* for the type of calls that customers can perform without the assistance of a CSR. What remains are more complex calls that may require additional handling time and knowledgeable CSRs to respond and resolve customer needs, and the Company is seeing an increase in average handle time (AHT) as CSRs are responding to more complex customer discussions. Thus, the new technologies being adopted by the Company will allow CSRs to spend the additional time with customers they need and deserve for complex issues, while other customers can navigate tasks via a digital channel if they prefer. The Company agrees, however, to a $0.95 million reduction to the overall O&M requested in this case to capture call volume reduction savings (250,000 reduction in calls multiplied by the existing vendor cost per call of $5.85, allocated 65% to DTE Electric) (Sparks, 7T 1642-1644, 1647; 7T 2266-2267).

Mr. Sparks further explained that Call Center staffing is driven primarily by average handle time (AHT) and call volume. Changes to call handling requirements and the need for continuous training and development, are driving the need to increase staffing levels. Since the start of the

COVID pandemic, the Call Center has had a heightened focus on exercising special care for the Company's most vulnerable customers. DTE has experienced approximately a 174 second AHT increase in calls that involve low-income customers because, for example, it takes extra time for CSRs to explain specialized COVID payment plans and properly pre-screen and advise customers on their options for agency resources (Sparks, 7T 1645-1646).

The PFD agreed with the AG's proposed disallowance for CSRs (as well as hiring lag and TOU costs, totaling 9.7 million), criticizing the Company's evidentiary presentation because it did not include additional items (PFD, pp 483-85).

The Company takes exception, incorporating the discussion above. Also as discussed in section II above, the standard is "preponderance of the evidence." The Company carried its initial burden and responded to AG witness Coppola. The AG is also responsible for supporting her own propositions yet abandoned her own witness's testimony. Furthermore, it is inappropriate to raise new issues after the record is closed and criticize the Company for not addressing them.

Therefore, the AG's proposed headcount cost disallowance should be rejected, but the Company agrees to a $0.95 million reduction to its overall O&M request to capture call volume savings as discussed above (Sparks, 7T 1644, 1646-1647).

3. Uncollectible Accounts Expense (Exhibit A-13, Schedule C5, line 8; Schedule C5.8)

DTE Electric included $59.6 million of uncollectible expense based on a three-year average of actual uncollectible expense for 2017-2020, excluding 2018, reflecting planned efforts to sustain results despite continuing economic challenges for many customers (Johnson, 5T 820-822; Exhibit A-13, Schedule C5.8, page 1, line 1, column (e)).[112] DTE Electric excluded 2018 because

[112] The costs associated with uncollectible expense are assigned based on net write-offs (Maroun, 6T 1041).

uncollectible expense was abnormally high due to system issues and delayed collections, resulting from the Customer 360 (C360) billing system implementation (Johnson, 5T 822).

Staff initially proposed a $9,560,000 downward adjustment, which it has revised to $4,174,000. AG witness Coppola proposed a $9.4 million reduction to $50.3 million (8T 4862-4864). The PFD discussed this topic, and seems to suggest favoring the AG's position, but never offers any specific recommendation (PFD, pp 488-93). Nevertheless, Appendix C reflects a disallowance for uncollectibles. Therefore, the Company takes exception.

Both the Staff and AG proposals are based on using the cash-basis method for estimating uncollectible expense. The Company recognizes that the Commission previously adopted Staff's cash-basis methodology (May 2, 2019 Order in Case No. U-20162, p 87), but maintains that the cash basis method of estimating uncollectible expense is inconsistent with how expense is recorded and with how other costs and revenues are calculated for both MPSC reporting and for ratemaking. The estimation of future expenses should be consistent with the practice used to record the actual expenses to ensure recovery of the Company's reasonable and prudent costs. An average of the amounts charged to FERC account 904 provides such consistency. The cash-basis method also does not factor in special circumstances that are accounted for under the accrual method (for example, delaying write-offs that are being disputed or negotiated, and the temporary suspension of disconnects during 2020 due to the pandemic). (Johnson, 5T 823-824, 828-829).

If the cash-basis method is to be used (which it should not be), then Staff's forecast using an updated 2019-2021 three-year average of net write offs as a percentage (%) of revenue to forecast projected uncollectible expense is reasonable, rather than the AG's selective use of 2017, 2020 and 2021 (Johnson, 5T 830-831). The PFD asserts:

> While DTE prefers the calculation performed with 2019-2021 data, its objection appears to be based on 2021 data, which Mr. Coppola did not use in his analysis. On

> this basis, the company's preference to use 2019 through 2021, when it acknowledges issues with both 2019 and 2021, is not a reason to reject Mr. Coppola's analysis. [PFD, p 493.]

To the contrary, Mr. Coppola used 2017, 2020, and 2021 in his analysis, so he plainly *did* use 2021. It is also inaccurate for the PFD to suggest that the Company's objection appears to be based on 2021, where Staff uses 2021. Moreover, Mr. Coppola's method is not a three-year average, but rather a five-year average with two years carved out of the middle. Therefore, and as further explained by Witness Johnson, if the cash-basis method is to be used, then Staff's three-year (2019-2021) average should be used.

If the cash basis is to be used, then two corrections[113] should also be made, which would result in an uncollectible expense of $55,398,915 million (Johnson, 5T 829-830; Exhibit A-37, Schedule BB1). Staff responded that it "audited the Company's exhibit submitted in rebuttal and agreed with the corrections. Staff projects that the Company's electric uncollectible expenses will be $55,398,915, a reduction of $4,174,085 from the Company's projection of $59,573,000" (Staff Initial Brief, p 175).

Therefore, the AG's proposal should be rejected. The Company also maintains its objection to the cash-basis method and supports its original projection; however, if the Commission agrees with Staff's methodology, then the proper amount is $55,398,915, in accordance with the Staff and Company's agreement.

4. Corporate Support (Exhibit A-13, Schedule C5, line 10; Schedule C5.10)

The Corporate Staff Group's (CSG) O&M expenses (excluding employee benefit costs, and after rate case adjustments and normalizations) as allocated to DTE Electric were $168.6 million

[113] They are: (1) include revenues associated with surcharges (Energy Waste Reduction, Nuclear Surcharge Revenue, LIEAF Surcharge Revenue) and incremental revenue from rate relief to avoid understating the revenue associated with uncollectible expense, and (2) do not double count the savings from the Business Rules Framework (BRF+) project.

for the 2020 adjusted historical test period, and are expected to increase to $176.1 million for the projected period ending October 31, 2023 (Uzenski, 7T 2722-2723; Exhibit A-13, Schedule C5.10, line 21, columns (f) and (l)). DTE Electric's proposed CSG cost-allocation methodology appropriately allocates costs based on the level of services consumed and is the same methodology that the Commission approved in DTE Electric general rate cases going back to Case No. U-13808, as well as DTE Gas's general rate cases going back to Case No. U-13898 (Uzenski, 7T 2724-2726).

The only dispute concerns the Staff's shifting and disallowance proposals, which are addressed above in section IV. E. 4 regarding IT project spend capitalization.

5. Pension and Benefits (Exhibit A-13, Schedule C5, line 11; Schedule C5.11)

DTE Electric projects $127.4 million of employee pension and benefits costs, which after adjustments for the portion of these costs capitalized, transferred and eliminated as being related to separate surcharge programs, results in a net employee pension and benefits O&M expense of $106.7 million for the projected test year (Cooper, 7T 1811; Exhibit A-13, Schedule C5.11 Revised).

v. Active Healthcare Benefits

DTE Electric incurs substantial costs to provide benefits to its active employees. These costs largely concern health care and are projected to increase from $41.4 million in the historic test year, to $55.5 million in the projected test year. This increase reflects (1) the normalization of the 2020 historical Active Healthcare costs for the non-recurring impact of a reduction in the Company's self-insured medical and dental costs resulting from the COVID-19 pandemic, and (2) an adjustment to reflect an historic average of constant dollar costs and thereby establish a sound starting point, which results in a total increase of $7.0 million. The 2020 normalized Active

Healthcare costs of $48.3 million are then escalated for the adjusted medical plan trend of 5.5% in 2021, 5.0% in 2022, and 4.5% in 2023 (Cooper, 7T 1796; Exhibit A-13, Schedule C5.11 Revised).

Mr. Cooper further explained that annual unadjusted medical trend factors of 6.5% for 2021, 2022, and 2023 are based on projections for healthcare trends provided by the healthcare experts at Willis Towers Watson (WTW), as reflected on Exhibit A-13, Schedule C5.11.1. [114] WTW's trend factors are adjusted by 0.5% to reflect the expected savings from the Company's Wellness program, (to 5.5% in 2021, 5.0% in 2022, and 4.5% in 2023), and are corroborated by a study by PricewaterhouseCoopers LLP's (PwC) Health Research Institute (reflected on Exhibit A-13, Schedule C5.11.2), which projects that medical costs will increase by 7.0% in 2021, and 6.5% in 2022 (Cooper, 7T 1806-1807).

AG witness Coppola proposed to reject the Company's normalization adjustments related to COVID-19 and constant dollar, and to instead take the average of 2020 Active Healthcare costs (which he incorrectly adjusted) and 2021 costs to get an average cost per employee of $10,834, which he then escalated by the average annual increase in costs per employee from 2017 through 2020 (2.5%) to arrive at $48.5 million after allocating a portion to capital expenditures (8T 4867-4869).

The PFD "recommends rejecting DTE's proposed constant dollar normalization adjustment… [and] adopting the more conventional projection proposed by the Attorney General, albeit with the corrections suggested by DTE… [with the] resulting healthcare expense projection of $50.3 million, which is a reduction of approximately $5.2 million form the company's position" (PFD, pp 503-504). [115]

[114] WTW first develops an Allowed Trend, which is then adjusted for the Company's actual plan design to develop the future Medical Plan Trend applicable to the Company (Cooper, 7T 1806).

[115] Despite recommending a $5.2 million adjustment; Appendix C reflects a $9.5 million reduction for Active Healthcare.

The Company maintains its original position, and that the AG's proposal should be completely rejected. The most obvious flaw in the AG's $48.5 million projection is that it is $2.8 million lower than the Company's $51.3 actual Active Healthcare expense incurred in 2021 (Cooper, 7T 1867; Exhibit A-35, Schedule Z2, column h, line 15). The $7.0 million difference between the Company's proposed $55.5 million projected Active Healthcare expense and the AG's $48.5 million projection relate to two basic issues: determining the proper historical base and the annual medical cost escalation factor that should be applied to that starting point. These differences are summarized in Table 2 of Mr. Cooper's rebuttal testimony (7T 1867). Mr. Coppola proposed a starting point of $45.3 million, which is $3.0 million less than the $48.3 million starting point proposed by Mr. Cooper. Mr. Coppola then used an annual escalation rate of 2.5% for the entire projected period, based apparently on an historical average of annual changes in the per employee Active Healthcare costs, whereas Mr. Cooper used annual escalation factors based on adjusted projections provided by WTW, as described above.

While Mr. Coppola did not adopt the Company's COVID-19 normalization adjustment, by using an average of 2020 and 2021 Active Healthcare costs, his normalized 2020 Active Healthcare expense is $0.7 million higher than the Company's COVID-19 normalized Active Healthcare expense. Consequently, the only substantive issue regarding the proper Active Healthcare expense to be used as a starting point before escalation is the Company's constant dollar Active Healthcare expense adjustment.

Mr. Coppola incorrectly characterized the Company's Constant Dollar normalization adjustment as "simply compounding inflationary increases on top of inflationary increases… [in a] brazen attempt to inflate forecasted O&M expenses" (8T 4867). The PFD was apparently persuaded by this incorrect characterization and faulted the Company because it "failed to thoroughly address

the Attorney General's concern that [normalization] could potentially result in compounding inflationary pressures" (PFD, p 503).

To the contrary, the AG is responsible for supporting her own propositions, as discussed in section II above. Mr. Cooper also thoroughly explained that normalization adjustment is needed to establish an accurate starting point because year-to-year volatility of actual Active Healthcare costs (which is largely driven by the Company's self-insurance of healthcare benefits, and changes in utilization) makes any historical period expense potentially unreliable as a starting point to project costs. The $3.8 million constant dollar normalization adjustment to the Company's actual 2020 Active Healthcare costs is designed to eliminate this volatility and reduce the risk of selecting an unrepresentative starting point (Cooper, 7T 1799-1802, 1874). The volatility of the Company's actual Active Healthcare costs is graphically demonstrated on Table 1 of Mr. Cooper's Direct testimony where annual changes range from an 18% increase in 2013 to a decline in 2020 of almost 5% (Cooper, 7T1801). It is this year-to-year volatility that the constant dollar adjustment is designed to mitigate.

Instead of "compounding inflationary increases," the mechanics (reflected on Exhibit A-13, Schedule C5.11.4 Revised) merely adjust the Company's historical Active Healthcare costs for each of the years 2016 through 2020 for the actual increases in medical costs as measured by PwC, with the 2020 trend rate adjusted downward by 0.5% for the impact of the Company's Wellness program. This produces a five-year average cost per employee on a constant dollar basis. By analogy, the Constant Dollar approach is similar to the conversion of historical nominal prices into real prices because the value of a dollar changes over time due to inflation. The Commission also adopted a similar approach in DTE Electric's last general rate case (May 8, 2020 Order in Case No. U-20561, p 86, rejecting the AG's exception to the use of a constant-dollar denomination for emergent

replacement expenditures, explaining in part: "Adding inflation to the five-year historic actual spend is appropriate for calculating the starting point for normalized expenditures."). The constant dollar Active Healthcare adjustment follows the same logic (Cooper, 7T 1802-1805).

The importance of using the constant dollar adjustment for determining the proper starting point for Active Healthcare expense is highlighted by the Company's experience in 2020, when the Company's Active Healthcare costs were suppressed due to the COVID-19 pandemic, and 2021, when the Company's Active Healthcare costs rebounded. Indeed, Mr. Coppola's use of an average of 2020 and 2021 Active Healthcare costs acknowledges the inaptness of the selection of a single year to establish a base. To demonstrate that the constant dollar methodology is not merely the application of inflation on top of inflation, as claimed by Mr. Coppola, a calculation of the constant dollar normalization adjustment using the same methodology as Exhibit A-13, Schedule C5.11.4, but based on years 2017 through 2021 shows that the constant dollar adjustment if 2021 was the historical test year would produce a reduction of $1.9 million (Cooper, 7T 1875, Exhibit A-35, Schedule Z4).

The Company recognizes that the Commission recently declined to adopt a similar constant dollar normalization adjustment for DTE Gas's Active Healthcare costs, "find[ing] a multi-year average adequately captures the volatility of the expense" (December 9, 2021 Order in Case No. U-20940, p 157). The Company disagrees, because averages of historical cost increases only measure annual changes in costs, which is distinguishable from determining the proper starting point, from which projected increases are then applied (Cooper, 7T 1804).

The Company also disagrees with the PFD's characterization of Mr. Coppola's methodology as a "more conventional projection" (PFD, p 503). Mr. Coppola also reduced 2020 costs by $3.1 million of COVID costs, which he characterized as "arbitrary," yet he acknowledged

"the decline in the health care cost in 2020 due to Covid-19 pandemic restrictions and fewer medical procedures performed in that year" (8T 4868). Thus, his methodology is inconsistent with acknowledged facts. Mr. Coppola's adjustment for 2020 also appears to be based on a misunderstanding of the Company's calculations (Cooper, 7T 1868-1870). If one were to use Mr. Coppola's overall approach then Exhibit A-35, Schedule Z3 reflects two necessary corrections to his calculations, resulting in a corrected Active Healthcare expense of $50.3 million (Cooper, 7T 1870-1871), which the PFD recommends (at p 504), and which is correct on this point, but inappropriate overall because Mr. Coppola's methodology should be completely rejected.

In addition to understating the proper starting point in the projection of Active Healthcare expense, Mr. Coppola also understated the annual escalation to be applied to that base. Specifically, Mr. Coppola computed an historical annual average of the Company's actual Active Healthcare costs of 2.5%. Mr. Coppola's use of the average change in Active Healthcare costs is also inappropriate due to the volatility in Active Healthcare costs, as discussed above, and because the Company's actual Active Healthcare costs is simply too small of a sample size to reliably predict the Company's future Active Healthcare costs. In contrast, the projected escalations prepared by WTW reflect inputs from WTW's national practice, the U.S Government and various other third-party data sources that produces a national trend assumption that is adjusted for the Company's benefit plan design (Exhibit A-13, Schedule C5.11.1, p. 4).

Mr. Coppola's use of an average of Active Healthcare costs from 2020 and 2021 also implicitly assumed that that all medical treatments not performed in 2020 due to the COVID-19 pandemic were performed in 2021, without any impact on costs in resulting years. This assumption ignores the reality that delays in the receipt of medical treatment (like a timely diagnosis) tend to increase the total cost of treatment. It is also likely that some medical treatments were postponed

into 2022, and the total effects of delayed medical care have yet to be realized. The likelihood that the Company will continue to incur elevated Active Healthcare costs is reflected in the 9.9% increase in the Company's Active Healthcare costs through March 31, 2022 as compared to the same period in 2021 (Cooper, 7T 1871-1872). Moreover, the impact of the COVID-19 pandemic on the Company's Active Healthcare costs has yet to be fully realized. In addition to the discussion above about postponing medical treatment, the long-term effects of COVID-19 will include the continued treatment of individuals with lasting symptoms ("long COVID") and the likely need for treatments for behavioral health problems (Cooper, 7T 1872-1873; See also Exhibit A-13, Schedule C5.11.2, p 5, reflecting a PWC study that states: "The pandemic's long tail may increase utilization and healthcare spending in 2022 thanks to the return of some care deferred during the pandemic").

Therefore, the Commission should approve the Company's requested $55.5 million Active Healthcare expense and reject the PFD recommended reduction of approximately $5.2 million (PFD, p 504).

6. Employee Compensation

DTE Electric takes issue with three recommendations of the PFD relating to the Company's incentive compensation programs for both its executive and non-executive employees. [116] First, DTE Electric seeks to recover the $63.8 million net projected test period incentive compensation expense, which excludes the expense allocated to the Company for DTE Energy's top five executives (Cooper, 7T 1821-1822). The performance measures included within the plans include

[116] The programs consist of short-term incentive plans provided through the Annual Incentive Plan (AIP), applicable to executive level employees, and Rewarding Employees Plan (REP), available to all other non-represented employees. In addition, the Company provides a multiple year incentive plan delivered through the Long-Term Incentive Plan (LTIP), which is generally available to managers and above, and up to 10% of other non-represented employees. Mr. Cooper provided a detailed description of the design and mechanics of these plans (7T 1814-1844, 1851-1852; Exhibit A-21, Schedules K1 through K7).

both operating and financial metrics. See generally, DTE Electric's Initial Brief, pp 211-21, which discusses incentive compensation in detail.

Staff proposed to exclude $42,537,000, representing incentive compensation expense related to financial measures, because past Commission decisions have done so. The PFD agreed, reasoning that "DTE presented the same basic analysis in this case as it has in prior cases" (PFD, p 521).[117] The Company does not dispute the Commission's prior findings in other cases, but maintains that the Commission has based its decisions on the evidence (*e.g.*, April 17, 2018 Order in Case No. U-18255, p 49) and has expressly recognized that "each case must be evaluated on the record in that case" (January 31, 2017 Order in Case No. U-18014, p 85). [118] Thus, financial measures have not been, and cannot lawfully be, categorically disallowed simply because the Commission has disallowed them in the past as PFD suggests.[119]

DTE Electric's proposal to include incentive compensation expense related to both the operating and financial measures is fully supported by the record in this case. DTE Electric provided an in-depth cost/benefit analysis demonstrating a $41.8 million net customer benefit ($105.6 million total customer benefits minus $63.8 million total incentive plan costs) (Cooper, 7T 1834-1835; Exhibit A-21, Schedule K6).

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[117] By adopting Staff's proposal, the PFD implicitly rejected the AG's further proposal for the elimination of 40% of incentive compensation expense related to operating measures ($8.490 million), as well as Energy Michigan's proposal for the disallowance of incentive compensation expense for all measures in which the costs are greater than the benefits, which the PFD also criticized (at pp 523-24).

[118] The Commission also approved Consumers Energy Company's (Consumers) cost recovery for its employee incentive compensation program (EICP), which was structured with 50% of an employee's incentive based on achievement of operational and performance measures, and the other 50% based on the achievement of financial measures (November 19, 2015 Order in Case No. U-17735, pp 73-74, 78).

[119] Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. The APA similarly precludes the Commission from making decisions based on non-record materials. MCL 24.276.

Incentive compensation programs are an increasingly prevalent practice among the vast majority of energy companies.[120] Therefore, DTE Electric must also offer incentive compensation opportunities to be competitive with other employers in attracting and retaining talented and qualified employees (Cooper, 7T 1815, 1822, 1844). The record further demonstrates that DTE Electric's incentive compensation programs allow the Company to attract and retain employees at a reasonable cost relative to its peer companies.

There is no evidence from any party in this case upon which the Commission could determine that the *total* annual compensation of DTE Electric employees is unreasonable or imprudent. Indeed, Staff specifically states that it does not dispute the overall reasonableness of employee compensation (Staff Brief, p. 176). Further, the focus on the variable portion of total compensation is also inappropriate because DTE Electric's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, DTE Electric's incentive compensation programs are one of two components that make up DTE Electric's total annual compensation package, which is comparable to other companies competing for the same employees (Cooper, 7T 1814-1815).

This point bears emphasis because the Commission's repeated denial of total incentive compensation expense is inconsistent with the reasonableness of total compensation. DTE Electric's analysis of virtually all incumbent salaries as of December 31, 2020 shows that the Company's total compensation is insignificantly different from market medians (Cooper, 7T 1817-

[120] A 2021 study by WorldatWork and Compensation Advisory Partners indicates that the vast majority of companies have both short-term and long-term incentive programs. Moreover, a 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers utilized broad-based incentive compensation programs (Cooper, 7T 1822).

1818, 1852; Exhibit A-21, Schedule K1).[121] Moreover, without the Company's short-term incentive compensation programs, the Company's pay would be 11.5% less than the market medians (Cooper, 7T 1818-1819).

Without the prospect of total annual compensation equal to the fixed plus the variable compensation components, DTE Electric would not be able to attract and retain a highly-skilled workforce, or provide incentives for its employees to engage in activities that benefit customers because total compensation would be substantially less than the peer companies. DTE Electric's incentive compensation programs also allow the Company to provide a lower level of base pay. If DTE Electric were to eliminate the variable element of compensation, then DTE Electric would need to provide a commensurate increase in base pay to attract and retain a highly-skilled workforce. This would increase the cost of employee benefits, such as life insurance and the Savings Plan, which are based on annual salaries (Cooper, 7T 1814, 1844, 1851).

Customers benefit every day from employees who have the requisite skills and experience to ensure the delivery of quality customer service. DTE Electric's compensation philosophy and framework benefit all customers by providing a high level of service at competitive costs, with properly-compensated employees having an at-risk element of compensation that provides incentives for safe, reliable, and efficient utility service that benefits every customer (Cooper, 7T 1814).

Turning to the Company's second issue, Staff's proposed $42,537,000 disallowance includes $1.064 million of Long-Term Incentive plan (LTIP) expense dependent on Nuclear Generation business unit operating measures. The PFD agreed, reasoning that "although

[121] Aon reviewed the data and techniques used by the Company, and concluded that the Company used best practices in sourcing the market pay data and developing estimated market values (Cooper, 7T 1820).

performance objectives are required to be met before performance shares are vested, the incentive is intrinsically linked to the potential to increase the value of the shares during the three-year performance period" (PFD, p 523).

This proposed disallowance is improper because the payouts are driven by operating measures that are unrelated to financial results (as the PFD acknowledged in the quote above), and therefore meet the Commission's traditional practice of requiring quantified customer benefits through improved reliability and lower costs (Cooper, 7T 1848-1850). Staff instead reasoned that although this is based 80% on operating measures, the entire payout should be disallowed because it is made in performance shares, which Staff viewed (inaccurately as discussed below) as dependent of the Company's financial operation (Staff Initial Brief, pp 177-78).

The Company's third issue concerns Staff's further proposal for the disallowance of $5,857,000 of Restricted Stock expense that the Company pays to employees, reasoning that it relates to the achievement of financial performance measures. The PFD agreed (PFD, pp 527-28).

To the contrary, Mr. Cooper explained that Restricted Stock, which represents $5.857 million of projected LTIP expense, is granted annually to encourage continued employment of certain key executives, and the value is not dependent on the Company's achievement of any financial measures. Therefore, Staff's proposed disallowance is unfounded and should be rejected (Cooper, 7T 1849, 1853).

Staff asserted that both Performance Shares and Restricted Stock are "based on DTE Energy Company stock prices, which is a financial measure used by the Company to determine the amount of the award" (McMillan-Sepkoski, 8T 5264). Staff's assertion is incorrect. The stock price is not used to measure the awards; instead, the stock is used as a medium to deliver the awards (like

dollars, bitcoin, or other methods of payment). The number of shares used to pay the LTIP grant is simply adjusted depending on the stock price when the grant is paid (Cooper, 7T 1850).

Similarly, with regard to the Nuclear Generation operating measures, the cost is no different than the AIP and REP costs relating to operating measures. The principal distinction is that these LTIP awards are made in stock rather than cash. This distinction in the *method* of payment (and not the underlying *measure* of payment) does not support different treatment (Cooper, 7T 1851).[122]

Staff also acknowledged that the restricted stock expense is recognized based on the value of DTE Energy's stock at the date of the grant, but ownership does not vest until typically three years from the grant (Staff Initial Brief, p 178). Thus, the grant is disconnected from DTE Energy's financial performance. For simple example, a $1,000 grant could be 10 shares of $100 stock, or 20 shares of $50 stock. Either way, the expense is $1,000, regardless of DTE Energy's stock price. Plus, the whole point of this discussion concerns DTE Electric's recovery of expenses (here, measured at the time of the grant). Whether employees ultimately make or lose money based on DTE Energy's stock price years later (as the PFD suggests at p 528) is irrelevant.

The PFD disagreed, quoting Exhibit S-8.3 (PFD, pp 527-28). But that exhibit states that: "When you own shares in the Company, you benefit financially…." (*Id*). The PFD disregards the temporal context. Employees benefit *after they receive stock* (assuming they keep it), depending on the Company's performance. That has nothing to do with the issue here, which concerns the *employees getting that stock in the first place*. That receipt of stock by employees does not depend

[122] Staff's proposal was also apparently based on an incorrect inference. Staff cited a phrase from the Company's LTIP employee plan description booklet (Exhibit S-3.6), indicating that the LTIP is "a reward to employees for assisting the Company in reaching its financial performance goals" (McMillan-Sepkoski, 8T 5264). Staff's inference is incorrect because the LTIP employee plan descriptive booklet describes the potential benefits to employees of future increases in DTE Energy's stock price, but that benefit has no impact on the Company's costs (Cooper, 7T 1853-1854).

on the Company's financial performance, as discussed above based on the record. Therefore, the PFD's recommendation should be rejected as unfounded and incorrect.

Therefore, the Commission should approve DTE Electric's request to include all of the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case and reject the PFD's proposed reduction of $42.5 million for incentive compensation expense and $5.9 million for restricted stock expense.

7. PERC (Exhibit A-13, Schedule C5.16)

DTE Electric's Initial Brief, pp 180-81, explained and supported Fermi 2's O&M expenses, and Program Evaluation Review Committee (PERC) Regulatory Asset amortization.

The AG proposed that DTE Electric not start the Extended Power Uprate (EPU) Study in 2023, and to remove the associated 2023 PERC O&M EPU expenditures of approximately $4.9 million. AG Witness Coppola reasoned that the "Company has not made a compelling and convincing case that the study would lead to an outcome that would provide a competitive cost of adding capacity even after considering that the added capacity would be carbon free" (8T 4856).

Company Witness Davis explained that the AG's position should be rejected as unreasonable and imprudent. The EPU Study is not being conducted to arrive at an "outcome" as Witness Coppola inaccurately indicated. Instead, the EPU Study is to provide a comprehensive and fully transparent analysis of the potential to safely operate Fermi 2 at EPU conditions, which would potentially increase the baseload, carbon-free generation capacity of Fermi 2 by approximately 172 Mwe. The EPU Study would also provide the Company with an improved understanding of the operational considerations required to operate Fermi 2 at EPU conditions, and narrow the uncertainty of scope, schedule, and expenditures associated with the work that would be required

to complete an EPU, which is a reasonable and prudent approach (Davis, 7T 2571-2572, 2585-2586). Mr. Davis further explained in a discovery response:

> Knowledge has value. Time has value. As I explained in my direct testimony and in my rebuttal testimony the Extended Power Uprate (EPU) Study will take several years to complete as it requires a refueling outage window to execute certain investigations and measurements. The Fermi 2 Power Plant has the potential for an additional 172 Mwe of carbon-free, baseload generation capacity that the Company could consider as a potential generation resource that could be evaluated in a future integrated resource plan – it is certainly reasonable and prudent to understand the opportunities and risks associated with such an uprate. [Exhibit AG-1.68.]

The PFD agreed with the AG, stating:

> This PFD agrees with the Attorney General and recommends disallowing the $4.9 million in funds for the EPU study. DTE did not rebut or address Mr. Coppola's analysis showing that an EPU—even at the low end of DTE's preliminary cost estimate—would be exceedingly uneconomical in terms of cost per MW when compared to the cost of capacity from other sources. Further, DTE appeared to offer no substantial reason to perform the study aside from desiring to obtain more specific knowledge regarding the potential EPU, which it already has reason to know was uneconomical. At best, the discovery response highlighted by DTE suggested that DTE might consider the additional Fermi 2 capacity as a potential generation resource in a future IRP. However, this PFD believes that potential use in resource planning cannot justify the $4.9 million study when DTE apparently already should have reason to believe that the EPU will be uneconomical even at the low end of its preliminary cost estimates. [PFD, p 532.]

DTE Electric disagrees. In addition to the discussion above, Mr. Coppola did not perform an "analysis" as the PFD suggests. Instead, he just made a broad proposition based on what he acknowledged was a "very preliminary estimate" of what an EPU might cost to arrive at a number for total project cost per MW, which he compared to "the MISO Zone 7 CONE cost [of] $94,000 per MW" (8T 4855-56). Mr. Coppola's comparison is also inaccurate and inapt because it assumes that a single CONE payment is equal to the total project cost for building a combustion turbine generation unit, which is not the case. Instead, CONE spreads the installed cost of a combustion

turbine over a 20-year payment schedule.[123] Thus, the AG's comparison between a "very preliminary estimate" of total project construction cost and a one-time CONE payment is grossly inaccurate, and there is no sound basis for the PFD to recommend that the Commission rule otherwise based on the Company not explaining something that is readily apparent and beyond credible dispute.

In any event, DTE Electric (and the Commission) should not be cut off from knowledge and options based on what the "PFD believes… DTE apparently already should have reason to believe" in the absence of the requested study. The EPU study is reasonable and prudent, so its cost should be approved.

8. Corporate Membership Dues.

In the Company's last general rate case, the Commission "remind[ed] the company of its continuing obligation to identify, describe, and explain projected costs associated with membership fees in future rate cases." (May 8, 2020 Order in Case No. U-20561, p 200). DAAO asserted that the Commission should disallow all corporate memberships that are not required by law for energy operations, because certain organizations allegedly spend some of their income lobbying against ratepayer interests.

Company Witness Ms. Crozier responded to the Commission and otherwise explained that the Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, and reliable energy. Exhibit A-27, Schedule Q1 lists corporate memberships included in DTE Electric's O&M expense. The benefits that the Company receives from the memberships listed in Exhibit A-27, Schedule Q1, pages 3-5 generally fit into one or more of the

[123] MISO defines CONE as being an *annualized* NPV value as opposed to a *total* NPV value. Page 197 of Exhibit MEC-81 (MISO Resource Adequacy Business Practice Manual 11) states, "In order to produce the *annualized* CONE value for each LRZ from these cost numbers, MISO assumes: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term;…" (emphasis added).

following categories: Benchmarking; Best practices; Research; and Networking. Some of the memberships are also a non-discretionary cost of doing business. *None of the membership costs associated with the organizations listed on Exhibit A-27, Schedule Q1 involve lobbying activities* (Crozier, 7T 2358-2359). Ms. Uzenski further explained how certain memberships and membership costs were excluded from customer rates (7T 2698; Exhibit A-3, Schedule C14).

The PFD rejected DAOO's proposed disallowance, but indicated a belief that that "the Commission contemplated more than the generic information that DTE provided" (PFD, p 534). The PFD further stated: "Given the limited information on this record, this PFD cannot identify a specific rate adjustment, but it recommends that the Commission take action to ensure that adequate information is provided in the company's future filings for the parties to evaluate the ratepayer benefits of membership, with an understanding of the cost." (PFD, pp 534-35).

DTE Electric agrees that no rate adjustment should be made, but disagrees with the PFD's suggestion that more information should be provided, incorporating the discussion above. Therefore, the Company takes exception and requests that the Commission grant full approval of DTE Electric's requested relief with respect to corporate membership dues.

VII. OTHER REVENUE RELATED ISSUES

A. Outage Credits

Company witnesses Crozier and Uzenski explained that the Commission recently proposed changes to the Service Quality and Reliability standards that might increase expense from higher customer bill credits. The Company believes that the added expense is a recoverable cost but is unable to predict the amount. Therefore, the Company proposes to defer the costs of the customer outage credits that it starts paying with the final order in this case, and to use account 182.3, Other Regulatory Assets, for that purpose. The deferred costs would only be for those customer outage

credits due to outages shown not to be the Company's responsibility, and the deferred amounts would be reviewed for reasonableness and prudency in a subsequent general rate case (Crozier, 7T 2359-2362; Uzenski, 7T 2770).

Staff's Initial Brief, p 272, stated: "Staff agrees with the Company's cost recovery proposal to a degree. The Staff agrees with the idea of deferring the costs into a regulatory asset and evaluating them in the next case for reasonableness and prudency. Staff does not entirely agree with the Company, however, that DTE Electric should recover outage credits paid out due to outages that were 'shown not to be the company's responsibility.'" Staff further indicated that the quoted language could be interpreted in an overbroad manner and offered a proposal to refine its meaning.

The PFD found Staff's proposal reasonable, after indicating that DTE Electric did not object to the proposal (PFD, p 603, citing DTE Electric Reply Brief, p 164).[124] Instead, DTE Electric's Reply Brief, p 164, states:

> The Company agrees that Staff's proposal is generally consistent with the Company's intent but disagrees with Staff's suggestion that only certain types of outages caused by third parties (i.e. including transmission system failures, customer failure to maintain clearances on service lines, but excluding automobile collisions) should be compensated. (Staff Initial Brief pp. 272-273). The list of the type of outages that would be specifically recoverable was presented as an example, not an exhaustive list. (7T 2360). The Company's proposal in this case is to defer the costs and specific cause types for later review in the first case when the costs are requested for recovery.

The Company maintains its position, and asserts that the Commission should adopt it as discussed above.

[124] The PFD implicitly rejected Kroger's argument that the Company should not recover outage credits (PFD, p 603), and the Company agrees as discussed at DTE Electric's Initial Brief, p 225.

VIII. COST ALLOCATION AND RATE DESIGN

B. Production Cost Allocation.

DTE Electric's Initial Brief, pp 228-34, explained and supported the Company's proposal to allocate costs among its customers. DTE Electric's Initial Brief, pp 236-40, further discussed the Company's capacity charge revenue requirement ($1,627.0 million, reflected on Exhibit A-16, Schedule F1.5 Revised, line 8). As relevant here, MNSC recommended that certain costs in the Company's cost of service study and SRM capacity charge calculation should be allocated differently, allegedly to better reflect cost causation. One of these items is the fixed costs of the Midwest Energy Resources Company (MERC) facility. The Company disagreed, explaining:

> MNSC never disputes that the MPSC has approved rates that include the MERC allocation in every case since U-15244. MNSC implies that the MPSC's consistent allocation treatment regarding MERC is of no import because: first, as to the treatment of MERC costs since DTE Electric's U-15244 rate case, the January 13, 2009 Commission Order in that case never discusses the assignment or allocation of MERC costs, nor does the allocation of MERC costs appear anywhere in the cost-of-service exhibit DTE filed in U-15244. This simple observation by MNSC, that MERC costs are not specifically addressed in the order or appear explicitly on an exhibit does not mean the Commission was unaware of their inclusion or how they were allocated, which both appear in the supporting workpapers submitted with the Company's underlying rate case filings. Commission intention and awareness is also demonstrated in MNSC's Initial Brief p. 98, citing the Case No. U-18248 November 21, 2017 Order which reflects a discussion of MERC costs[125] and their allocation in the capacity charge calculation.
>
> Even assuming any merit in any other points (which there is not, but the Company declines to recount history or otherwise burden the discussion), [126] MNSC's proposals would still be wrong and should be rejected under any realistic view of the overall picture. See also ABATE's Initial Brief, pp 19-31. [DTE Electric Reply Brief, pp 172-73.]

[125] In the Order, MERC is referred to obliquely as "a Wisconsin fuel handling facility." (Case No. U-18248 Order dated November 21, 2017, p. 33)

[126] See, for example, the April 18, 2018 Order in Case No. U-18255, p 54 (rejecting the RCG's challenge to full normalization ratemaking for the change in the City of Detroit tax rate, which the Commission decided in Case No. U-17767, where DTE Electric's witnesses did not re-present the status quo nor specifically recall the details on cross examination).

Despite this explanation, and after observing that MNSC largely abandoned its argument, the PFD stated:

> This PFD finds that MNSC's recommendation is reasonable, consistent with the NARUC manual, and not contrary to any specific instructions the Commission has provided. This PFD notes that DTE's contention that the Commission was aware of the company's cost allocation choices based on "workpapers submitted" with rate case filings is not sufficient to establish that the Commission has considered the appropriate classification and allocation of these costs. [PFD, p 608.]

DTE Electric disagrees, incorporating its prior discussion. Also as discussed in section II above, MNSC has the burden to support its proposed change, contrary to the PFD's suggestion that the Company had some burden to disprove it. MNSC's position boils down to the proposition that the MERC facility should be treated similar to fuel costs because it is a fuel-handling facility (reflected for example at PFD, p 606). The PFD's suggestion that the Commission never considered the MERC facility's well-known function or the well-established allocation is speculative at best, particularly in the context of acknowledging that the Company provided information to the Commission in rate case filings. Even if the Commission did not consider the issue previously, the Commission should certainly think carefully about it now, and not simply shift costs among the Company's customers as the PFD effectively recommends.

The Company allocated production plant and related costs using the 4CP 75-0-25 allocator, as explained by Mr. Maroun in his direct testimony (Maroun, 6T, 1033, 1039). The PFD recommended that the Commission consider a stand-alone case to investigate whether any change to the (production plant allocation) method should be considered, after DTE Electric's upcoming IRP case is resolved, when the Company's plans to meet capacity and energy needs going forward should be generally understood (PFD, p. 608-609). The Company disagrees with this proposal. First, such a recommendation is improper on its face, as no party proposed this in direct or rebuttal

testimony, or discussed the merits of the proposal. Second, the current 4CP 75-0-25 production plant allocation method was evaluated (Case No. U-17689) and explicitly reviewed, discussed, and confirmed in every subsequent DTE Electric rate case (Maroun, 6T 1039) including an extensive review in the two most recent cases: U-20162 (May 2, 2019 Order at p.125-128) and U-20561 (May 8, 2020 Order at p. 213-221). Therefore, this new recommendation for another stand-alone case is wholly unnecessary and burdensome. The appropriate approach is to continue reviewing the production plant allocation method in the context of the Company's rate cases,

C. State Reliability Mechanism (SRM) Capacity Charge

Mr. Maroun calculated and explained the Company's capacity charge revenue requirement, which is reflected on Exhibit A-16, Schedule F1.5 Revised. He used the same methodology that the Commission approved in its May 8, 2020 Order in Case No. U-20561. The capacity charge revenue requirement includes all production-related costs per Exhibit A-16, Schedule F1.1, except for adjustments for fuel, non-capacity-related purchased power, and variable O&M (Maroun, 6T 1028, 1043-1046). The resulting total capacity charge revenue requirement is $1,627.0 million (Exhibit A-16, Schedule F1.5 Revised, line 8). Mr. Maroun allocated it to the various rate classes using the 200B (4CP) allocator excluding Rider 10, which is the methodology approved in Case No. U-20561 (Maroun, 6T 1046). (See also generally, DTE Electric's Initial Brief, pp 236-40).

Staff asserted that the Company inappropriately included MISO Schedule 17 Market Administrative Costs as a fuel cost that offsets projected energy sales revenue (Gottschalk, 8T 5119). Energy Michigan proposed that any expenses other than fuel should be removed from the "net of projected fuel" calculation (Zakem, 8T 4505). The PFD agreed, stating in part:

> DTE's claim that it is using an approved method relies on a non-conforming calculation that somehow evaded review in Case No. U-20561. The company's calculation should be rejected for the reasons explained by Mr. Gottschalk and Mr. Zakem. [PFD, p 619.]

The Company disagrees because the Commission allowed the Company to include "Fuel-Related Costs" in Case No. U-20561, as these costs are all incurred as a result of producing energy from the Company's generation resources. Energy Michigan's Initial Brief, pp 2-3, acknowledged that "[t]his statement is true as far as it goes," but suggested that it is unclear why the Commission did so, and that Case No. U-20561 should be considered as an "inadvertent outlier."

The Company disagrees that Case No. U-20561 should not be followed. The treatment was, and remains, appropriate to ensure all customers are treated fairly. If any of these costs were to be excluded from the Fuel-Related Costs category, then the Company's PSCR customers would subsidize customers paying the SRM Capacity Charge. The energy sales revenue would also not be possible without incurring the Fuel-Related Costs, so anyone receiving the revenue benefit should bear the associated cost (Burgdorf, 4T 149).

The PFD's contrary recommendation is based on a lengthy criticism of DTE Electric for not filing something different in Case No. U-20561. The Company disagrees with the characterizations, but more importantly as discussed above, the method of subtracting the Fuel-Related Costs category remains the same as from Case No. U-20561, where the costs were discussed by the Company and properly included in the approved method of subtracting out Fuel-Related Costs. These costs remain appropriate for inclusion in Fuel-Related Costs to ensure all customers are treated fairly. These costs occur only with the production of energy from the Company's generation assets. To give the benefit of energy sales to customers being charged the SRM without including all of the attributable costs to produce the energy would be unfair to the Company's PSCR customers who would end up paying those extra costs, thereby subsidizing customers on the SRM Capacity Charge (Burgdorf, 4T 123, 150-151).

Therefore, the PFD's recommendation should be rejected, and the Company's SRM calculation should be adopted.

Mr. Maroun also explained in direct testimony that only non-labor portions of Accounts 501 (Fuel Handling), 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 Electric Maintenance Expenses) and 548 (Peaker Expenses) should be included in variable O&M (Maroun, 6T 1045). MNSC disagreed with this methodology, claiming that O&M labor for handling fuel is obviously non-capacity-related, and therefore should be included in variable O&M (Maroun, 5T 1056). The PFD supported MNSC's recommendation (PFD, p 608). The Company's disagrees. First, as described in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual, labor expenses are considered demand-related, while material expenses are considered energy-related (Maroun, 6T 1045). Second, it is contrary to the Commission approved methodology in place since the inception of the capacity charge calculation in Case No. U-18248 and in subsequent rate cases (Maroun, 6T 1056).

D. Uncollectible Expense Allocation

DTE Electric proposed to continue to allocate uncollectible expense by customer class. Staff recommended "allocating uncollectibles based on total revenue, as this is how the bills (that represent the amounts that may end up uncollectible) are determined. In addition, this method properly reflects that expenses related to uncollectibles are a general cost of doing business" (Gottschalk, 8T 5111). The PFD agreed with Staff, stating:

> This PFD finds the Staff's recommendation to be reasonable and in accordance with recent methods approved by the Commission in cases U-20963 and U-20940. Therefore, Staff's recommendation to allocate uncollectible expense on the basis of total revenue should be adopted. [PFD, p 623.]

The Company disagrees because it is well established in rate making that similarly-situated customers are grouped together for purposes of setting rates for the class as a whole. The appropriateness of a cost allocation method is determined by examining cost causation of the class as a whole, not by comparing individual members within a class. The Staff/PFD recommendation would result in customer classes being allocated a share of uncollectible expense that is disproportionate to costs caused by the class. For example, in 2020, residential and commercial secondary classes were responsible for 98.5% of net write-offs, but only 76.4% of total revenue. The Commission previously agreed with the Company's use of net write-offs to allocate uncollectible expense in Case Nos. U-17689, U-17767, and U-18014, observing for example that it is "appropriate and consistent with regulatory ratemaking principles to directly assign such costs to the class that caused the costs" (June 15, 2015 Order in Case No. U-17689, p 27). Therefore, the PFD's recommendation should be rejected as lacking a sound basis and contrary to ratemaking principles (Maroun, 6T 1067-1068).

E. Residential Rate Design Proposals

Exhibit A-16, Schedule F3 shows the present and proposed rate designs and corresponding revenue by rate schedule. (See generally, DTE Electric's Initial Brief, p 241).

1. Time of Use (TOU) Full Implementation

In the April 18, 2018 Order in Case No. U-18255, pp 81-82, the Commission directed DTE Electric to include in its next rate case filing a summer on-peak rate for non-capacity charges for Rate Schedule D1 (residential customers). In the May 2, 2019 Order in Case No. U-20162, pp 164-165, the Commission adopted an implementation plan for this transition, and directed DTE Electric to test capacity and non-capacity rates through pilots. The Commission approved pilot Rate

Schedules D1-A and D1-B, along with the broader Advanced Customer Pricing Pilot (ACPP) in the September 26, 2019 Order in Case No. U-20602 (Foley, 6T 1135).[127]

Rate Schedules D1-A and D1-B both have an on-peak period of 3:00 pm to 7:00 pm, Monday-Friday (with an off-peak period consisting of all other times), and on-peak rates that are different for June-September versus October-May. For both rates, the power supply non-capacity rate differential between on-peak and off-peak is derived from differences in historical Locational Marginal Prices (LMPs) for the corresponding seasonal and intraday periods. Rate Schedule D1-A's power supply capacity rate is a "flat" per kWh energy charge that remains constant regardless of date and time. For Rate Schedule D1-B, both power supply non-capacity and capacity rates vary by time and month, and the differential between on-peak and off-peak is based on the relative difference between the LMPs instead of the absolute difference (Foley, 6T 1136-1137).

The Company initially proposed the full implementation of TOU rates using proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), which mimics the structure of Rate Schedule D1-A. In response to a Staff audit request, the Company provided its "Alternative TOU Full Implementation proposal," which, among other things, incorporated a rate design that applies TOU pricing to both the capacity and non-capacity portions of power supply (supplemental response to Audit DWI-1.1; Exhibit A-45, Schedule JJ1 Revised). (See generally, DTE Electric's Initial Brief, pp 241-46).

After a lengthy discussion (beginning at PFD, p 627), the PFD criticized the Company's cost estimates as inconsistent with past cases, and the lack of collaboration with "all stakeholders"

[127] The ACPP began enrolling residential customers in the first quarter of 2021 to better understand residential customer preferences and responses to a variety of TOU plans, recruitment and messaging approaches, and ongoing engagement. Exhibit A-13, Schedule C5.9.2, lines 2-7, shows the related costs (Burns, 7T 2496-2497).

in the development of the alternative proposal (PFD, pp 651-54), and then recommended further delay, or in the alternative a modified version of the Company's initial proposal, stating:

> This PFD recommends that the Commission delay implementation of the full time-of-use rates once again, direct DTE to file a one-year review of the pilot programs and to confer with stakeholders on the design of a full time-of-use rate. This PFD further recommends that the Commission require DTE to provide the basis for each of the cost estimates it provided the Commission regarding work related to time of use rates, including the cost estimates in Mr. Serna's affidavits in Case No. U-20602, in its IT business cases presented in this case and in Case No. U-20561, and in Mr. Foley's, Mr. Sparks' and Mr. Burns' testimony in this case. Future cost estimates accompanying a full time-of-use rate proposal should be accompanied by detailed cost estimates with vendor bid results and a detailed transition plan including educational and marketing materials.
>
> Should the Commission nonetheless wish to approve a full time-of use rate in this case, this PFD recommends that the Commission approve the company's initial proposal, with the pilot result of a 0.4% load shift, grant deferred accounting for its capital and O&M costs, subject to review for reasonableness and prudence, and require the same reporting and same scrutiny of the company's cost estimates as discussed above. [PFD, p 655.]

The Company takes exception to the PFD's recommendation for further delay. The TOU effort has been underway and studied (in various proposals and pilots) for almost five years. Further delay would result in unnecessary costs and administrative burdens for no tangible benefit.

While the PFD seems to reflect some difficulty in understanding the previous and forecasted costs for the Company's ACPP and its proposed TOU full implementation, the Company has nonetheless presented accurate cost estimates for its proposals for which the Commission can assess prudency. More specifically, the PFD criticized the Company's historical projections of costs for contemplated TOU implementation. Obviously, the nature of TOU implementation has changed over the years and remains unresolved pending the Commission's Order in the instant case. More importantly, however, the Company presented an accurate cost estimate for the present proposal for full TOU implementation. The one-time project costs associated with the Company's TOU full implementation initial proposal consist of $31.7 million of capital costs for Customer IT, and $17.1

million of O&M costs, consisting of $8.1 million for Customer Outreach, $4.9 million for Customer Service, and $4.1 Million for Customer IT (Foley, 6T 1151-1152; Burns 7T 2498; Exhibit A-13, Schedule C5.9.2 lines 9-12, column (e)). The one-time project costs associated with the Company's Alternative TOU Full Implementation proposal is an anticipated capital cost of $19.5 million and anticipated O&M cost of $11.9 million (see Exhibit S-23.00 pages 3-4).

As indicated above, the PFD's alternative recommendation also includes a 0.4% load shift (PFD, p 655). The Company assumed a 3% shift from on-peak to off-peak on its proposed D1.11 and D1.12 TOU rates. CEO witness Lucas asserted that the Commission should approve "no more than a 0.4% shift in summer… and a 0% shift in non-summer peak to off-peak usage. This more conservative approach reflects the reality that the proposed D1.11 and D1.12 TOU price signals are very weak" (8T 3586). The Company disagrees. The Company's conservative and reasonable proposal is based on preliminary pilot results and precedent in the State of Michigan. Witness Lucas additionally failed to consider the dynamics of rate implementation impacting all residential customers versus the results of a managed pilot. Moreover, following implementation of the D1.11 rate the Company will have usage data for approximately 1.9 million customers expected to take service on the rate. It will propose billing determinants in future rate cases based on actual and observed data after sufficient reliable historical information becomes available. (Willis, 6T 977-978).

As it relates to the enrollment strategy for customers, the February 4, 2021 Order in Case No. U-20602, p 6, ordered DTE Electric "to file its full plan for implementation of summer on-peak rates for capacity and non-capacity charges in time to achieve full implementation of the new rates for summer 2023." The Commission also "clarifie[d] its expectation that, while the ACPP program includes both opt-in and opt-out enrollment paths for each of the approved pilot rates, the ultimate

program to be fully implemented in 2023 will be either a default or opt-out program that more closely mirrors cost of service." (*Id*, p 5).

Accordingly, the Company's initial proposal uses an "opt-out" strategy in which all residential customers taking service on the D1 (Residential Service Rate – Base) rate would be given at least 60 days' notice that they are being transitioned to the D1.11 rate. Through customer outreach, customers will receive a series of communications via multiple channels meant to inform, educate, and provide tips on how to save on a TOU rate. A customer could opt-out of the transition by notifying the Company of their desire to do so, and remain on the D1 rate.[128] The D1.11 rate would also become the default rate for new residential customers and customers changing premises, similar to how the D1 rate presently acts as the default rate. (Foley, 6T 1146-1148; Burns, 7T 2498). The Company further proposed its "Alternative TOU Full Implementation" proposal in response to Audit DWI-1.1 Exhibit A-45, Schedule JJ1 Revised. The alternative proposal utilizes a mandatory enrollment strategy, in contrast to the initial proposal's "opt-out" strategy. As such, both the Company's initial and alternative proposals for TOU full implementation are consistent with the referenced order.

Therefore, the Company's proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), either as originally proposed or as defined in the "Alternative TOU Full Implementation" proposal in DWI-1.1, should be approved, along with related cost recovery.[129] In the event that the Commission approves the "Alternative TOU Full Implementation", the

[128] This same process (but with somewhat different messaging) would apply to customers taking service on the D1-A and D1-B rates, and those rates would be retired and removed from the Company's rate book once all pilot customers are transitioned to other rates (Willis, 6T 926-927; Foley, 6T1151).

[129] If the Commission orders a different rate design, then customer behavior that is different than what underlies proposed Rate Schedule D1.11 could potentially be expected. Therefore, the Commission should also allow the Company to adjust the projected billing determinants associated with the ordered rate design to ensure cost recovery (Foley, 6T 1145-1146).

corresponding contract term language in Exhibit A-16, Schedule F8, sheet D-14.06 should reflect the default nature of the rate schedule and therefore the "Contract Term" provision in Exhibit A-16, Schedule F8, sheet D-14.06 should be stricken and replaced with the contract term language set forth on Exhibit A-16, Schedule F8, sheet D-2.00. The Company maintains its support for a Commission Order approving either its initial or alternative TOU full implementation proposals.

2. Billing determinants

The Unbundled Cost of Service (UCOS) studies for DTE Electric's projected test period are consistent with past practices, including the cost-allocation methods approved in Case No. U-20561 (Maroun, 6T 1027-28; Exhibit A-16, Schedules F1.1 and F1.2). The Company proposes to continue using the same allocation methods for transmission and production that were approved in the May 8, 2020 Order in Case No. U-20561 (Maroun, 6T 1028, 1038-1039). The Company proposes to allocate distribution by voltage level class (residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals[130]), consistent with the allocation method that the Commission approved in Case No. U-20561 (Maroun, 6T 1039).(See generally, DTE electric Initial brief, pp 228-31).

CEO witness Lucas suggested that the Company's approach to allocating its sales forecast among residential rate schedules is not methodologically appropriate. He asserted that the Customer Usage change portion of the residential sales forecast "should be prorated over all the classes like the other adjustments rather than consolidated into D1" when considering residential billing

[130] Lighting is maintained as a separate class because it has a significant amount of dedicated infrastructure costs that should be assigned directly (Maroun, 6T 1039).

requirements, and further recommended that rates should then be recalculated with the new billing determinants (Lucas, 8T 3597).

The Company disagreed because its method to allocate residential sales is consistent with the method used in past cases, including the approved method in Case No. U-20561. CEO witness Lucas apparently agreed that there is no inherent flaw in the Company's method, stating that "[i]n a normal case… this approach may be fine" (8T 3596), but suggested that 2020 was abnormal because of COVID. Nonetheless the Company's forecasting is accurate (as the PFD recognizes at p 462), and Mr. Lucas did not articulate why his proration approach might be more appropriate than the Company's method. Finally, Mr. Lucas suggested a forecasted per capita change to D1 usage of 8.2%, when considering customer increases and excluding impacts of weather (8T 3594). This is substantially similar to the 7.03% per capita change across the full residential forecast, since D1 sales comprise approximately 89.6% of forecasted residential sales. Different methods often yield different results, but neither Mr. Lucas nor the PFD articulated why Mr. Lucas' method for allocating sales amongst residential rate schedules is intrinsically more accurate or appropriate. Thus, Mr. Lucas' suggested distinction between D1 adjustments is overstated and does not suggest any error in the Company's methodology or calculation (Willis, 6T 979-980).

Despite this explanation, the PFD agreed with CEO, stating:

> This PFD concludes that the CEO recommendation should be adopted in so far as it seeks to spread the additional sales reductions across the other residential rate schedules. Mr. Willis is clearly capable of making the modifications, since he was able to identify the magnitude, and did not dispute that DTE spread other adjustments to the different rate schedules. While Mr. Willis may be correct that it makes little difference to the ultimate rates given the size of the D1 customer group, it would appear to be more proper. [PFD, pp 657-58.]

The Company disagrees for the reasons indicated above. The PFD also neglects that much of CEO's discussion was premised on an indirect challenge to DTE Electric's sales forecast, which

was sponsored by Mr. Leuker (*e.g.*, CEO's Initial Brief, p 24: "In creating its sales forecast for the upcoming test year, the Company likely over-emphasized the nature of its rate bases 'return to work' plans related to COVID-19," and p 27, indicating that Mr. Lucas disagrees with Mr. Leuker about residential usage patterns). CEO offered no support for what it may consider "likely," [131] and Mr. Lucas has no qualifications to dispute the forecast made by the Company's forecasting expert (See section II above), and which the PFD recognized as valid (PFD, p 462). Therefore, the Commission should approve DTE Electric's allocation methodology and reject the recommendation proposed by the PFD.

3. Energy Assistance

Staff and the Company have different versions of tariff provisions, with the disagreement largely about Staff's proposal that LIA enrollment should be done randomly. Company witness Johnson outlined the goals, results, and synergies of the Company's energy assistance programs, including programs that the Company devised and implemented in response to the COVID-19 pandemic (5T 805-819). In response to Staff's indicated concerns about prioritizing 5,000 senior citizen customers to receive the LIA credit (Braunschweig, 8T 5272) she further explained that the Company appropriately addressed bill affordability for some of the Company's most vulnerable customers (Braunschweig, 5T 831-832). Staff's proposal to randomly apply LIA credits to low-income customers (Braunschweig, 8T 5272) would also reverse the current successful policy of pairing the LIA with the Low Income Self Sufficiency Plan (LSP) (Johnson, 5T 832).

[131] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

In further response to Staff's indicated concern about tariff language allowing the Company's discretion in the distribution of the LIA enrollment (Braunschweig, 8T 5272-5273), Ms. Johnson explained that the tariff allows the Company to act appropriately to ensure that all funds are distributed, but it does not allow the Company to move away from what has been ordered. The Company agrees that it is important to engage Staff when considering how it distributes the credit; however, a requirement to consult with Staff and file a case with the Commission every time the Company determines it should adjust the distribution of the credit could significantly hinder the ability to adjust as needed for vulnerable customers who need assistance (Johnson, 5T 832-833).

The PFD found that "it is premature to revise the tariff language," and instead "recommends that the company file a report detailing its current approach to enrolling customers in the LIA credit program, as well as current (2021 and 2022 to date) enrollment data. Once DTE's report is filed, this PFD recommends that the parties engage in discussions through the Energy Affordability and Accessibility Collaborative (EAAC)… . The other "clarifying" changes DTE and Staff propose appear to be unnecessary to address at this time" (PFD, p 662).

The Company is certainly willing to further discuss this and other matters with Staff, but maintains that, as summarized above, it has fully supported its proposals on the record in this case, and Staff's contrary proposals would be inappropriate for vulnerable customers who need assistance. Therefore, the Company's proposals should be adopted.

4. Rate D1.12, the residential "Stable Bill Service Level" demand-based tariff

The Company does not currently offer any residential rate schedule that utilize demand rates or demand-based charges.[132] Demand-based rates benefit customers by providing a third way to

[132] The Company proposed four pilot demand rates along with the D1-A and D1-B rates that the Commission approved in Case No. U-20602 (discussed above), but the Commission declined to approve them in that context, stating:

manage their usage and potentially reduce their bills. In addition to reducing usage (with volumetric rates) and shifting usage (with TOU rates), demand-based rates give customers the ability to stagger their usage (not use multiple high-demand appliances at the same time) in order to reduce their peak demand and lower their bill (Foley, 6T 1152-1154). Therefore, the Company proposes to establish Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level). (See generally, DTE Electric's Initial Brief, pp 246-50).

Staff and some Intervenors raised criticisms, and the PFD recommended rejection of the Company's proposal, stating:

> The PFD agrees with Staff, MNSC, the CEOs, MEIBC/IEI, and others that DTE's Stable Bill proposal should be rejected, and all costs associated with implementing the proposed rate should be disallowed. As multiple witnesses testified, Rate D1.12 is not cost based; it does not send accurate or actionable price signals to participating customers, and without constant vigilance, customers could face significant cost penalties for up to one year. [PFD, pp 669-70.]

The Company maintains that its proposal merits consideration and the criticisms are overstated. The proposed D1.12 rate would be a voluntary tariff available to all residential customers, with three main components: (1) a per kWh TOU energy charge to recover energy-related costs, such as fuel and purchased power, and which would mimic the Company's proposed D1.11 rate to ensure consistency across rates; (2) a fixed monthly delivery service charge set equal to the delivery service charge incorporated into other base residential service tariffs; and (3) a monthly Customer Service Level charge based on the demand that an individual customer places on the system (Willis, 6T 932-33; Foley, 6T 1154-55).

> The Commission declines, at this time, to approve the remaining four proposed pilots, all of which deal with demand pricing, which the Commission finds should be addressed separately. The Commission finds that it will be beneficial to implement the two energy pilot rates and avoid overcomplicating the effort. Additional discussions regarding demand charges would be warranted prior to implementation. [September 26, 2019 Order in Case No. U-20602, pp 3-4.]

The Customer Service Level charge is designed to equitably recover all costs not collected through the per kWh TOU energy charge or the delivery service charge by assigning each customer to a "service level" based on the demands they place on the system. First a customer's "service size" would be determined by calculating the average of the customers' three highest use hours during the previous twelve billing cycles, including the current billing cycle (or as much billing history as is available). Then the customer would be assigned to a service level. Each service level has a fixed monthly charge, with higher service levels having higher charges (Foley, 6T 1156-1157).

Customers would be able to change service levels and be subjected to higher or lower service level charges if they make behavioral changes (*e.g.*, staggering their usage to manage high use hours) or by fundamentally changing their load (*e.g.*, installing more efficient appliances to reduce their overall load). The Company believes that using twelve months of usage history to determine a customer's service size strikes the right balance between providing bill stability (from month to month, potentially only the energy charge portion of the bill would change based on actual usage) and allowing customers to manage their usage and control the size of their bill. It also better ensures equitable recovery of costs by protecting against inefficient users (with relatively high usage "spikes") that are driving an outsized level of costs in the system (Foley, 6T 1158-1159, 1161-1162).

The proposed D1.12 rate is designed to be revenue-neutral to Rate Schedule D1. Exhibit A-16, Schedule F3, pp 12-13 reflects the design of the rate. The Company does not propose a pilot to test the new rate. Instead, the Company intends to notify customers that the rate is available and provide education about it through its typical channels and methods. The Company also intends to limit the number of customers taking service under the proposed D1.12 rate to 10,000 to ensure that

it can properly assess the impacts of the new rate while also limiting the potential for unintended consequences (Willis, 6T 930; Foley, 6T 1164-1166).

Staff and some Intervenors raised various arguments against the proposed D1.12 rate, and the PFD found those arguments persuasive as indicated above. In the paragraphs that follow, the Company will briefly respond to four of these arguments, with further details in Mr. Foley' rebuttal testimony (6T 1192-1202).

Staff (Revere, 8T 5138) and MNSC (Jester, 8T 3854) recommended rejecting the proposed D1.12 rate, claiming demand charges are unnecessary and/or inefficient. The Company disagrees because demand charges are a well-established tool for larger customers. No compelling argument has been offered as to why this rate structure could not be extended to residential customers, providing them with benefits including new ways to manage their bills. Therefore, the Company maintains that the most appropriate path is for the Commission to approve the proposed D1.12 rate and for the Company to closely track customers' engagement with the rate. This would provide actual customer data and experiences that would allow for a more robust discussion in the future (Foley, 6T 1193-1194).

Staff (Revere, 8T 5138) and some Intervenors recommended rejecting the proposed D1.12 rate, claiming it is not cost-aligned and that "service levels" are unnecessary and/or inappropriate for residential customers. The Company disagrees with arguments that the proposed D1.12 rate is not cost-aligned. There appears to be broad agreement that various measures of demand, such as aggregate class peak, play an important role in driving and allocating costs; however, residential customers do not presently receive any type of direct pricing signal to manage their demand. A broad pricing signal to manage demand at all times would achieve a higher level of cost-alignment than the status quo. The structure of the proposed D1.12 rate is also necessary to achieve the levels

of bill stability outlined in Witness Foley's testimony which, in turn, would potentially create value for some customers (Foley, 6T 1161, 1194-1197; Exhibit A-45, Schedule JJ2). The Company acknowledges, however, that there are multiple ways to achieve higher levels of cost-alignment, and would potentially be supportive of alternative demand-based structures if the Commission deemed them appropriate to implement. Therefore, while the Company maintains that its proposed D1.12 rate is appropriate, it would also generally support TOU demand charges as a way to better achieve cost-alignment, although any specific application would need to be closely assessed (Foley, 6T 1197-1198).

Some Intervenors proposed to reject the proposed D1.12 rate because it would allegedly send unhelpful and/or unactionable price signals. These criticisms are not unique to the proposed D1.12 rate, and merely reflect that all rate design involves some level of imprecision and must balance real-world limitations. Importantly, however, rate design should encourage efficient consumption behaviors where possible, and the current residential rates do not include any type of demand-based charges despite various measures of demand playing an important role in driving and allocating costs. As indicated above, the Company maintains that a broad pricing signal to manage demand at all times would achieve a higher level of cost-alignment than the status quo. As such, the best path forward is to approve the proposed D1.12 rate to obtain actual data and experiences to inform a more robust discussion in the future (Foley, 6T 1200-1201).

GLREA witness Rafson proposed to reject the proposed D1.12 rate, claiming that it would result in "unjust enrichment" and "enhance DTE's profits" (8T 3262). The Company disagrees, noting that witness Rafson apparently confused how required revenues are allocated through the Company's COSS and how rates are designed. The D1.12 rate is designed to collect the exact amount of revenue allocated to the D1 class through the COSS. Thus, the D1.12 rate is "revenue

neutral" to the D1 rate, and would not have any impact on the Company's revenues or profits as compared to the current rate design (Foley, 6T 1164, 1202).

Therefore, the Company's proposed Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level) should be approved.

F. Commercial and Industrial Rates

ABATE witness Andrews proposed providing a credit to primary voltage customers with a monthly power factor greater than .9 in the amount of 0.5% of the energy charges on the bill, and no changes to the currently-approved power factor penalties for customers with a power factor less than .85 (8T 2999-3000). The PFD begins to discuss the issue, but does not offer a recommendation (PFD, pp 673-74).

The Company agrees with ABATE that a power factor less than the currently-approved threshold of .85 imposes a material enough cost to warrant a penalty, but the Company disagrees that being slightly above the penalty threshold (.9 vs .85 in ABATE's proposal) is a reason to offer a credit. The Commission should reject ABATE's proposal because, as witness Andrews acknowledged, customers with a power factor of less than 1 induce losses. The Company should not provide credits to customers who continue to induce losses simply because their losses are relatively less than another customer's losses.

ABATE's Initial Brief, p 73, n 53, responded by suggesting that less of a loss is a benefit. To the contrary, a loss is a loss. The Company should not provide credits to customers who continue to induce losses simply because their losses are relatively less than another customer's losses. Credits should only be issued for absolute savings to the system, because otherwise (as with ABATE's proposal) other customers would effectively have to fund the credit. ABATE's proposed credit threshold is also arbitrary and unjustified (Willis, 6T 997-998).

Credits should only be issued for absolute savings to the system, because otherwise (as with ABATE's proposal) other customers would effectively have to fund the credit. ABATE's proposed credit threshold is also arbitrary and unjustified (Willis, 6T 997-998).

Therefore, the Commission should reject ABATE's proposal.

1. Rider 3

Bloom witness Morse mischaracterized Rider 3 standby charges as high and somehow constituting a "barrier to customers who would otherwise adopt technology," particularly Bloom's fuel cell product (8T 4536). Bloom witness Jester made various assertions about Bloom's product and "utility-caused outages," and on that basis recommended that the Commission do four things (8T 4556). The Company disagreed with all of the recommendations (6T 972-986). (See generally DTE Initial Brief, pp 270-74. Staff's Initial Brief, pp 254-57, also discusses why Bloom's claims and proposals should be rejected).

The PFD "agrees with DTE and Staff that Bloom's recommendations concerning Rider 3 should be rejected at this time" (PFD, p 685). The problem is that the PFD further stated (after recounting reasons for rejecting Bloom's recommendations):

> That said, the PFD finds that in the company's next rate case, DTE should be directed to provide a proposal to reduce the reservation fee for fuel cell systems, based on FOR [forced outage rate] for these systems, or provide a justification for why it would be unjust or unreasonable to do so. [PFD, p 685.]

The Company disagrees, in part, because rate cases are already unwieldy, as reflected for example by the PFD being 729 pages long. The Company should not be required to address this issue in a future filing, particularly in this context. The Company and Staff presented extensive and compelling evidence showing, among other things, customer privacy concerns, a lack of information on forced outages, and the inappropriateness of Bloom's attempt to obtain a cost-shifting subsidy for its fuel cell product to be paid by all other customers. After properly rejecting

the evidence and arguments associated with Bloom's proposal, it is inappropriate for the PFD to recommend, with seemingly no justification, that the Company make a similar proposal, or "provide a justification" for what it has just established in this case.[133]

2. Rider 10 Administrative Charge

The Company initially proposed a 50% credit for the Rider 10 class contribution to Allocation Schedule 100 (Power Plant Energy Production) (Crozier, 7T 2357). Staff supported the Company's proposal for this case, and also recommended that the R10 class should not be allocated any production plant and non-fuel production O&M costs by Allocation schedules 100 and 200A in the Company's next base rate case (Staff Brief, pp. 237-238). However, the PFD further expands this cost allocation change and recommends the Rider 10 administrative charge be entirely eliminated in the Company's next general rate case (PFD, p. 692). If the entire Rider 10 administrative charge is eliminated, it would not only remove production plant and non-fuel production O&M costs in allocation schedules 100 and 200A as recommended by Staff, but also eliminate the allocation of other future production costs such as working capital or uncollectible expense, which would then be allocated to other customer classes.

G. Distributed Generation (DG) Tariff (Rider 18)

The May 2, 2019 Order in Case No. U-20162 approved an alternate version of the Company's proposed Rider 18 for customers taking Distributed Generation (DG) service. The Commission ordered (1) that total inflow be charged at the retail rate of the underlying rate schedule (as the Company proposed), (2) that the outflow credit be set at the power supply rate less

[133] Although *res judicata* and collateral estoppel do not apply "in the pure sense" to MPSC decisions, issues decided in earlier MPSC proceedings need not be relitigated in later proceedings unless a party presents new evidence or shows by changed circumstances that the earlier result is unreasonable. *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1, 420 NW2d 156 (1988).

transmission costs (based on the customer's underlying rate schedule), and (3) that the Company's proposed System Access Contribution (SAC) charge be rejected. Exhibit A-16, Schedule F7 calculates the outflow credits using the same methodology approved by the Commission in Case Nos. U-20162 and U-20561. The PSCR factor is not included (for administrative convenience due to the frequent changes in the PSCR factor); however, when calculating the actual outflow credit applied to customer bills, the Company will add or subtract the current PSCR factor (Willis, 6T 934-935).

In Case No. U-20561, Staff suggested that the Company voluntarily accept applications into the DG program beyond the statutory 1% cap.[134] The Company declined to do so because lifting the 1% cap could expose the Company to uncapped revenue shifts and expose non-DG customers to increased and improper cost subsidizations (U-20561, 4T 495-496).

The Company proposes changes to Rider 18. First, the Company proposes to set the outflow credit, on a per kWh basis, to be the total of (1) the average monthly MISO hourly LMP for the DTE Electric appropriate load node, calculated and applied separately for each pricing window for customers taking service on TOU rates, and (2) a credit for avoided line losses as calculated through the Company's most recent line loss study (Exhibit A-36, Schedule AA-1). This proposal best reflects the cost impacts realized by the Company from Rider 18 outflow, and corrects the overpayment currently being made to Rider 18 customers (by the rest of the Company's customers) for the capacity portion of power supply. It also corrects the inconsistencies inherent in the current Rider 18 structure and properly aligns the Rider 18 outflow credit with the "Energy Only Sales"

[134] MCL 460.1173(3) relevantly provides: "An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years."

provision of Rider 5, where Qualifying Facilities (QFs) selling only energy when it is available receive a market-based price for the energy they provide (Willis, 6T 936; Foley, 6T 1170-1177).

Second, the Company proposes that future customers taking service under Rider 18 will also take service under the Company's proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate, as discussed above. Customers who install a DG system and take service under Rider 18 do not reduce the number of customers served by the Company or their average NCP demand, so these customers are not driving any delivery cost savings. Yet these same customers typically consume a portion of their generation onsite, so they reduce the volume of energy they purchase and the corresponding delivery portion of their bills. In other words, Rider 18 customers are able to reduce the delivery portion of their bills without the Company being able to realize a similar amount of cost savings. Thus, delivery costs are being shifted from Rider 18 customers to non-Rider 18 customers.[135] The Company's proposal to require use of the proposed D1.12 rate would correct this by appropriately charging customers based on the peak demand that they are placing on the system (Willis, 6T 936; Foley, 6T 1170, 1177-1180).

The Company proposes that these changes to Rider 18 not take effect until the latter of the Company hitting any of the category-specific reservations established by MCL 460.1173(3) (*i.e.*, 0.5% for Category 1 customers; 0.25% for Category 2 customers; or 0.25% for Category 3 customers) or the first quarter of 2024.[136] At that time, all new Rider 18 residential customers will be required to take service under D1.12 and their DG installation, and Rider 18, must be associated

[135] Thus, current circumstances are contrary to MCL 460.1177(4), which provides, in part, that: *"Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges."*

[136] Until that time, the Company proposes a clarification to Rider 18 language regarding outflow compensation for customers (both commercial secondary and primary) taking service on a demand-based rate, as reflected on Exhibit A-16, Schedule F8 (Willis, 6T 937-938).

with their D1.12 service. All existing Rider 18 customers will be subject to the updated outflow compensation but may remain on their existing inflow rates. This would (1) provide adequate time for current and potential Rider 18 customers and other interested stakeholders to prepare for changes, (2) eliminate customer confusion that might otherwise be present if changes to Rider 18 were made at the same time as the Company's TOU Full Implementation, and (3) allow the Company to dedicate adequate resources and focus on its TOU Full implementation (Willis, 6T 935; Foley, 6T 1181-1182).

Third, if the Commission approves the Company's above-described changes to Rider 18 as proposed, then the Company is prepared to voluntarily increase the size of its DG program to 3.0% of the Company's average in-state peak load for full-service customers during the previous five (5) calendar years as set forth in the proposed tariff language offered by witness Foley. As part of this voluntary increase, the Company would not enforce category-specific capacity limits or reservations beyond the minimum level of participation reserved for each category as authorized in MCL 460.1173(3). (Foley, 6T 1169, 1182-1185).

1. Inflow Rate Design

As indicated above in section VIII. D. 4, the PFD agreed with Staff and some Intervenors that the Company's proposed D1.12 should be rejected. Here, the PFD states: "For the reasons discussed at length above, this PFD recommends that the D1.12 Stable Bill tariff be rejected" (PFD, p 694). The Company disagrees, incorporating its prior discussion. (See also DTE Electric's Initial Brief, pp 261-63).

2. Outflow Compensation

Staff and certain Intervenors asserted various arguments regarding the Company's proposal to modify Rider 18 outflow to be based on average monthly LMPs, adjusted for line losses. The

Company responds to the arguments collectively below, with further details in Mr. Foley's rebuttal testimony (6T 1213-1225). (See generally, DTE Electric's Initial Brief, pp 263-66).

The PFD "finds that Staff's proposed outflow credit should be adopted, along with GLREA's recommendation that DTE purchase RECs from DG customers and apply those RECs to the VGP program .[137] In addition, this PFD disagrees with DTE's claim that because DG customers are not obligated to provide capacity, these customers should not be compensated for any capacity they might provide" (PFD, p 701). The Company disagrees as discussed below.

[137] Furthermore, there is no authority to impose this requirement. In *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155-56; 596 NW2d 126 (1999), our Supreme Court explained:

> "The Public Service Commission has no common-law powers. It possesses only that authority granted by the Legislature. *Union Carbide [v Public Service Comm,* 431 Mich 135,] at 146, 428 N.W.2d 322. Moreover, this Court strictly construes the statutes which confer power on the PSC. As this Court explained in *Union Carbide, supra* at 151, 428 N.W.2d 322, quoting *Mason Co. Civic Research Council v Mason Co,* 343 Mich 313, 326–327, 72 NW2d 292 (1955):
>
> "The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist."

See also *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm*, 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.) All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), amended 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003). *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority"). *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). *Wayne Co v Hathcock*, 471 Mich 445, 478; 684 NW2d 765 (2004). See also *Shizas v City of Detroit*, 333 Mich 44, 50, 59-60; 52 NW2d 589 (1952); *Bd of Health v Van Hoesen*, 87 Mich 533, 537; 49 NW 894 (1891) ("The state has no right to take the property of one citizen, and give it to another, whether with or without compensation"). *Missouri Pacific Ry Co v Nebraska*, 164 US 403, 417; 17 S Ct 130; 41 L Ed 489 (1896) (reversing order of the Nebraska State Board of Transportation requiring a railroad to surrender parts of its land to private persons for the purpose of building and maintaining their elevator on it, explaining: "The taking by the state of the private property of one person or corporation, without the owner's consent, for the private use of another, is not due process of law, and is a violation of the 14th Article of Amendment of the Constitution of the United States").

Staff (Revere, 8T 5139; Matthews, 8T 5384) and certain Intervenors recommended to reject the Company's proposal, arguing that outflowed energy has capacity value that should be paid to Rider 18 customers. The Company disagrees and maintains that current Rider 18 outflow compensation, which includes the retail component of power supply capacity based on a customer's inflow rate schedule, represents a clear overcompensation for that outflow (Foley, 6T 1219-1220). Mr. Foley further explained:

> The Company's retail inflow Power Supply Capacity rates reflect the embedded cost of a Power Supply portfolio that is designed to be dispatchable and meet aggregate customer demand at all hours of the year. DG outflow is intermittent, non-dispatchable, and under no obligation to perform at any hour of the year, let alone every hour of the year. As such, the value that the Company's Power Supply capacity portfolio delivers, as recovered through retail inflow Power Supply Capacity charges, is well beyond what DG outflow delivers. Therefore, compensating DG outflow at those retail inflow Power Supply Capacity rates represents a clear overpayment for the value that DG outflow provides.
>
> Further, the fact that outflow compensation is dependent on a customer's choice of retail inflow rate schedule represents a clear deficiency in the current Rider 18 design. The impact of outflow on the Company's resource adequacy obligations, or the cost of those obligations, does not depend on a customer's underlying retail inflow rate schedule. For example, a kWh of outflow will have the same system impact and value regardless of if a customer takes base service on the D1 rate or the D1.2 rate. However, presently the compensation for that outflow can vary significantly based on that customer's choice of underlying retail rate schedule. That customer could be compensated very differently for their outflow simply because they chose to take inflow service under a different rate. This inconsistency, by definition, proves that the current Rider 18 structure is not cost-aligned given that outflow which has the same value can be compensated so differently. [6T 1220.]

Therefore, the Company maintains that the most appropriate compensation for DG outflow is equal to the near-term cost savings that the Company is able to realize from that outflow, which is an LMP-based credit adjusted for avoided line losses (Foley, 6T 1221).

Staff (Revere, 8T 5140) and certain Intervenors recommended that Rider 18 outflow compensation should include the transmission component of power supply. The Company disagrees because the Commission previously "agree[d] with the ALJ's recommendation to adopt the Staff's

proposal to calculate the outflow credit based on power supply less transmission" (May 2, 2019 Order in Case No. U-20162, p 180). Also, there is likely little or no transmission savings associated with DG outflow, and neither Staff nor any Intervenor presented any new data or analysis to show that such savings exist. Further, the recommendation is contrary to MCL 460.1177(4), which provides, in part, that: *"Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges."* The statute (MCL 460.1177(4)) goes on to provide two options, and the Commission chose one of them when it initially set the outflow compensation in Case No. U-20162. Therefore, the recommendation should be rejected as unfounded and contrary to law (Foley, 6T 1221-1225).[138]

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[138] There is no authority to impose this requirement. In *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155-56; 596 NW2d 126 (1999), our Supreme Court explained:

> "The Public Service Commission has no common-law powers. It possesses only that authority granted by the Legislature. *Union Carbide [v Public Service Comm,* 431 Mich 135,] at 146, 428 N.W.2d 322. Moreover, this Court strictly construes the statutes which confer power on the PSC. As this Court explained in *Union Carbide, supra* at 151, 428 N.W.2d 322, quoting *Mason Co. Civic Research Council v Mason Co,* 343 Mich 313, 326–327, 72 NW2d 292 (1955):
>
> "The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist."

See also *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm*, 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.) All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), amended 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003). *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority"). *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). *Wayne Co v Hathcock*, 471 Mich 445, 478; 684 NW2d 765 (2004). See also *Shizas v City of Detroit*, 333 Mich 44, 50, 59-60; 52 NW2d 589 (1952); *Bd of Health v Van Hoesen*, 87 Mich 533, 537; 49 NW 894 (1891) ("The state has no right to take the property of one citizen, and give it to another, whether with or without compensation"). *Missouri Pacific Ry Co v Nebraska*, 164 US

GLREA witness Richter proposed that the Commission order a new Rider, under which DTE Electric would purchase Renewable Energy Credits (RECs) from customers with renewable energy systems, and "the credit for the RECs would be set at 80% of the net premium, Rider 17 (or whatever it is called in the future) customers are paying for green energy… [and the] remaining 20% of the value of the RECs would reduce the Rider 17 premium" (8T 3216). The Company disagrees because it reached a settlement agreement in Case No. U-20713, which included amendments to the eligibility and structure of Rider 17. Therefore, any discussion of legacy Rider 17 is ill-timed and inappropriate in this case. The discussion of an updated Rider 17 would be appropriate in the Company's Section 61 proceedings (Crozier, 7T 2395-2396).[139]

In addition to the quote above, the PFD states:

> This PFD disagrees that requiring the purchase of RECs from DG customers is particularly ill-timed or otherwise inappropriate to address here, noting that changes to Rider 17 eligibility and structure have no impact on how the company acquires green energy, which could be purchased at a discount from DG customers under Rider 18. The PFD therefore recommends that the Commission adopt Staff's suggestion that DTE work with interested stakeholders to revise Rider 18 to reflect the purchase of RECs, and that the company be directed to submit an application for *ex parte* approval within 90 days of the date of the Commission's order. [PFD, p 703.]

The Company disagrees, incorporating its discussion above, including that the appropriate venue for any lawful Rider 17 changes is the Company's Section 61 filing which was filed on August 31, 2022 in Case No. U-21172. There are far fewer issues in a Section 61 filing than in the

403, 417; 17 S Ct 130; 41 L Ed 489 (1896) (reversing order of the Nebraska State Board of Transportation requiring a railroad to surrender parts of its land to private persons for the purpose of building and maintaining their elevator on it, explaining: "The taking by the state of the private property of one person or corporation, without the owner's consent, for the private use of another, is not due process of law, and is a violation of the 14th Article of Amendment of the Constitution of the United States").

[139] See also *Union Carbide, supra*; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs).

instant case and the interested parties will be able to contemplate proposed changes with any related issues impacting the voluntary green program tariff in a forum dedicated to such a discussion.

3. Program Design and Additional Issues

Some Intervenors suggested that the Commission can or should establish a successor tariff to the current Rider 18 that would become effective once the category-specific reservations of the Company's DG program are met. The Company disagrees because tariffs already exist (specifically Rider 14 and Rider 5) that can apply to DG customers once MCL 460.1173(3)'s category-specific reservations are met. The Company is not offering, and does not support, the creation of any additional tariffs involving customer generation (Foley, 6T 1229-1231). See also *Union Carbide, supra*; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs). The PFD states:

> The PFD agrees that a just and reasonable, post-cap DG tariff should be developed. As several parties point out, DG systems are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act and, as such, DTE is obligated to purchase QF power at the utility's avoided costs. However, given the time constraints and number of issues that need to be addressed in this rate case, a successor tariff to Rider 18 should be referred to a separate proceeding. Accordingly, the PFD recommends that the Commission direct DTE to file, within 90 days of the date of this order, a proposed tariff for DG post-cap, including Rider 5 or Rider 14 if DTE believes these programs to be reasonable successors to the current DG program. [PFD, p 705.]

The Company disagrees as indicated above – both Rider 5 and Rider 14 are available to customers today without any additional Commission action. Furthermore, the Commission just approved a settlement agreement in Case No. U-18091 that definitively addresses the timing of the

next proceeding pursuant to MCL 460.6v and/or PURPA. (Case No. U-18091 Order dated July 7, 2022) The Company further observes that MCL 460.1173(3) plainly states: "An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years." It is also axiomatic that statutes must also be applied as written.[140]

The PFD's "post-cap DG tariff" recommendation neglects that the Commission possesses only the limited authority that the Legislature conferred upon it,[141] and "agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature."[142] The Commission also cannot avoid the controlling law through creative labeling (*e.g.,* calling "DG" something other than "DG"). [143] The Court of Appeals also recently invalidated a rule because it conflicted with a statute in *Emagine Entertainment, Inc v Dep't of Treasury*, 334 Mich App 658, 664; 965 NW2d 720 (2020), explaining in part that it was unlawful for an agency to "writ[e] a rule to alleviate what it considers to be a statutory gap… In a nutshell, the [agency] did not have the authority to circumvent the legislative process and administratively amend [a statute.]"

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[140] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("We presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"). *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

[141] *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999).

[142] *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008).

[143] "Courts are not bound by the labels that parties attach to their claims." *Buhalis v Trinity Continuing Care Services*, 296 Mich App 685, 691; 822 NW2d 254 (2012). Instead, it is "well settled that the gravamen of an action is determined by reading the complaint as a whole, and by looking beyond mere procedural labels to determine the exact nature of the claim." *Buhalis*, 296 Mich App at 691-91, quoting *Adams v Adams (On Reconsideration)*, 276 Mich App 704, 710-11; 742 NW2d 399 (2007). See also, *Local 1064, RWDSU AFL-CIO v Ernst & Young*, 449 Mich 322; 535 NW2d 187 (1995) (affirming the trial court's rejection of the plaintiff's contention, explaining in part that it is well-established that a court may "look behind the technical label that plaintiff attaches to a cause of action to the substance of the claim asserted"); *Aetna Cas & Sur Co v Sprague*, 163 Mich App 650, 654; 415 NW2d 230 (1987) (rejecting mischaracterizations as a "transparent attempt to trigger insurance coverage").

The Company further notes that the PFD's simplistic reference to the Public Utilities Regulatory Policies Act of 1978 ("PURPA") neglects that PURPA is complicated and difficult in application, as the Commission presumably has come to appreciate. A full discussion is beyond the scope of this brief, but the Company generally incorporates its filings in Case No. U-18091, which recently settled after years of proceedings (July 7, 2022 Order in Case No. U-18091).[144]

The PFD further stated:

> DTE should also be directed to address the conflict between MCL 460.6 ("The public service commission is vested with the power and jurisdiction to regulate all rates, fares, fees, charges, services, rules, conditions of service, and all other matters pertaining to the formation, operation, or direction of public utilities[,]") and the company's contention that the creation a successor tariff would invade management prerogative under *Ford Motor Co., supra*, or *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988).

The PFD's recommendation is unwarranted, and apparently based on the incorrect premise that MCL 460.6 grants authority to the Commission, which is contrary to overwhelming and controlling authority. For example, in *Huron Portland Cement Co v Public Service Comm*, 351 Mich 255; 88 NW2d 492 (1958), our Supreme Court quoted MCL 460.6 and explained:

> The broad language, however, furnishes no grant of specific powers. It is an outline of jurisdiction in the commission and does not purport to be more. If, indeed, the general language quoted had the effect of granting particular, specific powers in the commission, not only would a constitutional question be presented arising from an asserted lack of standards… but there would have been no need whatever for the many statutes enacted (both before and after the effective date of PA 1939, No. 3) vesting specific powers in the commission. [351 Mich at 263 (citations omitted).]

See also, *Union Carbide, supra*, 431 Mich at 147 ("Although its language is broad, [MCL 460.6] merely serves as an outline of the commission's jurisdiction, not as a grant of specific authority or powers").

[144] See also MCL 460.1177(4) with respect to the two permissible choices for outflow compensation (the Company's Rider 18 proposal utilizes one of the two permissible choices) and note that DG customers undoubtably receive a different and additional service than the Company's 2 million other full-service customers that only receive power inflows.

Since MCL 460.6 grants no authority to the Commission, there is no "conflict" with the Company's management prerogative as the PFD suggests. The PFD also neglects that the Company's control over its own property is a crucial element of the Company's property rights.[145] The Commission's relationship to the Company is as a utility regulator, and not a utility manager. Our Supreme Court aptly described the bounds of regulation in *Union Carbide* as follows:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. "It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." [citations omitted].[146]

Moreover, the PFD's recommendations appear to have been influenced by suggestions that the Commission should require DTE Electric (and effectively the Company's non-DG customers) to subsidize DG customers and/or private businesses (*e.g.*, third-party solar suppliers and/or installers to sustain or advance the solar industry), which presents an additional, constitutional problem because the Company's private property would essentially be taken by another private entity. Mich Const 1963, art 10, §2 provides that: "Private property shall not be taken for ***public use*** without just compensation therefor being first made or secured in a manner prescribed by law" (emphasis added). The Fifth Amendment of the United States Constitution similarly provides that "the government may not take private property unless it is done for a public use and with just

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[145] See generally, *Loretto v Teleprompter Manhattan CATV Corp*, 458 US 419, 435-36; 102 S Ct 3164; 73 L Ed 2d (1982) (holding that a New York law requiring a landlord to permit a cable television company to install cable facilities on the landlord's property constituted a taking of the landlord's property); *Kaiser Aetna v United States*, 444 US 164, 176; 100 S Ct 383; 62 L Ed 332 (1979) (a requirement that subjected a formerly private pond to public access took away the landlord's right to exclude, one of the most essential sticks in the bundle of rights that are commonly characterized as property").

[146] See also *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best."); *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority").

compensation."[147] Taking DTE Electric's private property and giving it to other private entities (*e.g.*, by asserting control over property and forcing its use to supply subsidized service) violates the "public use" requirement.[148] The Commission's authority does not include the ability to take property for the private use of another.[149] DTE Electric's status as a publicly-regulated company does not deprive it of constitutional protections against takings.[150]

As indicated in section II above, the Company appropriately raises these constitutional issues, recognizing that the Commission lacks authority to decide them since "an agency exercising quasi-judicial power does not undertake the determination of constitutional questions or possess the power to hold statutes unconstitutional."[151]

Also as a matter of basic utility law, the prior regulatory practice of subsidized rates has since been eliminated by legislation. The law requires that the Commission set cost-based rates. MCL 460.11 states in part:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of service to each customer class.

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[147] *Silver Creek Drain Dist v Extrusions Div, Inc*., 468 Mich 367, 374; 663 NW2d 436 (2003).

[148] *Wayne Co v Hathcock,* 471 Mich 445, 478; 684 NW2d 765 (2004). See also *Shizas v City of Detroit*, 333 Mich 44, 50, 59-60; 52 NW2d 589 (1952); *Bd of Health v Van Hoesen*, 87 Mich 533, 537; 49 NW 894 (1891) ("The state has no right to take the property of one citizen, and give it to another, whether with or without compensation").

[149] *Bohn Lumber, Prod v Public Service Comm*, 317 Mich 174, 182; 826 NW2d 875 (1947).

[150] *Missouri Pacific Ry Co v Nebraska*, 164 US 403, 417; 17 S Ct 130; 41 L Ed 489 (1896) (reversing order of the Nebraska State Board of Transportation requiring a railroad to surrender parts of its land to private persons for the purpose of building and maintaining their elevator on it, explaining: "The taking by the state of the private property of one person or corporation, without the owner's consent, for the private use of another, is not due process of law, and is a violation of the 14th Article of Amendment of the Constitution of the United States").

[151] *Wikman v Novi*, 413 Mich 617, 646-47; 322 NW2d 103 (1982); *Taylor v Detroit Edison Co*, 475 Mich 109, 122; 715 NW2d 28 (2006)

The statute's plain language must be applied as written - cost causers shall pay their costs.[152] Regardless of how one may feel about the conceptual benefits of DG, third-party economics are the responsibility of third parties, not the Commission or the Company. The Company is simply trying to apply cost-causation principles so that non-DG customers do not subsidize DG customers. Similarly, the Commission is to set cost-based rates in this context, and does not extend to shifting ratepayer funds to subsidize third-party businesses.

H. Community Solar

Staff and DAAO made proposals indicating similar goals, but with very different ideas about how a community solar project might be designed (*e.g.*, even on the fundamental issue of size). The Company maintains that the Commission should not adopt a community solar project in this case because there is not enough time to evaluate any proposal here. For example, the incremental capital and O&M costs to upgrade the Company's billing system and administer such a program have not been considered. The Company also currently has two community solar pilots that were part of the Company's last VGP filing, Case No. U-20713. The Company believes that adding another community solar pilot with similar goals would not be beneficial, but does agree to discussions to inform the potential for future programs. (Crozier, 7T 2384-2387). [153] The PFD states:

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[152] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); and *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[153] See also *Union Carbide, supra*; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best"); *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs).

> This PFD acknowledges that it is not feasible to design a community solar pilot project in the confines of a 10-month rate case. After reviewing the testimony and the arguments presented, however, this PFD is convinced that a logical first step toward enabling such a pilot is to create a facilitating tariff. Given the connection of a community solar program to the VGP program, this PFD recommends that the Commission require DTE to amend its Rider 17 Voluntary Green Pricing tariff to provide for such programs to be developed and offered through the VGP program…
> .
> [T]his PFD recommends that the Commission require DTE to revise the Rider 17 tariff to permit the utility to offer customers who are subscribers of a community solar organization the opportunity to participate in the VGP under terms and conditions agreed to by DTE and the subscriber organization, with the approval of the MPSC under MCL 460.1061. This tariff should be drafted to permit a program meeting the description in Exhibit S-17 and as described by Ms. Baldwin. This tariff provision will not require any action by DTE to implement the tariff at this point, but will facilitate the development of pilot programs in the VGP proceedings. [PFD, pp 709-10.]

The Company agrees that a community solar project should not be ordered in this case, but otherwise disagrees, incorporating its discussion above and previous discussion about the PFD's Rider 17 recommendation. The Company also disagrees that the contemplated tariff is a "logical first step." Tariffs in all other instances reflect well considered rates and programs, and are not proposed or approved as a method to spur a discussion. The Commission should decline to order the implementation of the proposed program or the filing of the Staff's tariff. The Company is not offering, and does not support, the creation of any additional tariffs involving community solar in this proceeding, through a revised Rider 17 filing requirement, or otherwise. However, the Company believes that a Company VGP proceeding would be the appropriate place to discuss community solar (Crozier 7T 2387).[154]

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[154] There is no authority to impose this requirement. In *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155-56; 596 NW2d 126 (1999), our Supreme Court explained:

> "The Public Service Commission has no common-law powers. It possesses only that authority granted by the Legislature. *Union Carbide [v Public Service Comm,* 431 Mich 135,] at 146, 428 N.W.2d 322. Moreover, this Court strictly construes the statutes which confer power on the PSC. As

IX. REQUEST FOR RELIEF

DTE Electric respectfully requests that the Commission issue its final order:

A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachments A and B) approving rates that will recover the Company's revenue deficiency of approximately **$367.2 million**, based on a November 1, 2022 through October 31, 2023 projected test year;

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this Court explained in *Union Carbide, supra* at 151, 428 N.W.2d 322, quoting *Mason Co. Civic Research Council v Mason Co,* 343 Mich 313, 326–327, 72 NW2d 292 (1955):

"The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist."

See also *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm*, 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.) All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), amended 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003). *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority"). *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). *Wayne Co v Hathcock*, 471 Mich 445, 478; 684 NW2d 765 (2004). See also *Shizas v City of Detroit*, 333 Mich 44, 50, 59-60; 52 NW2d 589 (1952); *Bd of Health v Van Hoesen*, 87 Mich 533, 537; 49 NW 894 (1891) ("The state has no right to take the property of one citizen, and give it to another, whether with or without compensation"). *Missouri Pacific Ry Co v Nebraska*, 164 US 403, 417; 17 S Ct 130; 41 L Ed 489 (1896) (reversing order of the Nebraska State Board of Transportation requiring a railroad to surrender parts of its land to private persons for the purpose of building and maintaining their elevator on it, explaining: "The taking by the state of the private property of one person or corporation, without the owner's consent, for the private use of another, is not due process of law, and is a violation of the 14th Article of Amendment of the Constitution of the United States").

B. Approving an annual revenue increase effective as soon as possible in the projected test year;

C Approving new rates effective as early as November 21, 2022 in the manner described in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachments A and B);

D Approving DTE Electric's proposed capital structure and return on equity;

E. Granting DTE Electric's request for tree trimming expenditures, and the associated request for regulatory asset treatment through 2024;

F. Approving recovery of DTE Electric's generation investments;

G. Approving recovery of DTE Electric's investments related to the strengthening of the Company's distribution system and reliability improvements;

H. Granting DTE Electric's request to approve the PSCR base;

I. Approving DTE Electric's proposals to implement certain customer rate schedules and tariffs;

J. Approving all proposed pilot programs as requested by the Company;

K. Approving all proposed regulatory accounting treatments as requested by the Company;

L. Approving a capacity charge based on the methodology established in Case No. U-20561 and the capacity-related costs approved in this proceeding;

M. Approving the remainder of DTE Electric's proposals and requested relief as set forth in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and

B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachments A and B); and

N. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY

Legal Department

Dated: October 5, 2022

By: Jon P. Christinidis Digitally signed by Jon P. Christinidis Date: 2022.10.05 16:47:53 -04'00'

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DTE Electric Company
Computation of Revenue Deficiency
Projected 12 Month Period Ending October 31, 2023
($000)

MPSC Case No. U-20836
Exceptions to PFD
Attachment A

Line No.	(a) Description	(a) Source	(b) U-20836 Reply Brief Position	(1)	(c) Adjustments	(d) U-20836 DTE Exceptions Position
1	Rate Base	Attach A, Page 2	$ 21,242,782		$ (7,806)	$ 21,234,976
2	Adjusted Net Operating Income	Attach A, Page 3	912,824		88	912,912
3	Rate of Return	Attach A, Page 4	5.56%		0.00%	5.56%
4	Income Requirements		1,180,249		(434)	1,179,815
5	Income Deficiency (Sufficiency)		267,425		(522)	266,903
6	Revenue Conversion Factor	Exh, A-13, Sch. C2	1.3496		-	1.3496
7	**Revenue Deficiency (Sufficiency)**		**$ 360,926**		**$ (705)**	**$ 360,221**
6	Tree Trim Surge	Exh, A-11, Sch. A1	7,021		0	7,021
7	**Revenue Deficiency (Sufficiency)**		**$ 367,947**		**$ (705)**	**$ 367,242**

(1) As the text and attachments of the ALJ's Proposal for Decision had noted differences, the Company is providing its Attachments A & B with the DTE Reply Brief as the starting position

DTE Electric Company
Rate Base - Average Net Plant
For the 12 Month Average Period Ending 10/31/2023
($000)

MPSC Case No. U-20836
Exceptions to PFD
Attachment A

Line No.	(a) Description	(b) U-20836 Reply Brief Position	(1)	(c) Adjustments		(d) U-20836 DTE Exceptions Position
1	Plant in Service	$ 25,082,094		$ (8,100)	(2)	$ 25,073,994
2	Plant Held for Future Use	66,804				66,804
3	Construction Work in Progress	1,620,679				1,620,679
4	Total Utility Plant	26,769,577		(8,100)		26,761,477
5						
6	Less: Depreciation Reserve	6,928,981		(294)	(3)	6,928,687
7						
8	Net Utility Plant	19,840,596		(7,806)		19,832,790
9						
10	Net Capital Lease Property	16,402				16,402
11	Net Nuclear Fuel Property	155,492				155,492
12						
13	Total Utility Property and Plant	20,012,490		(7,806)		20,004,684
14						
15	Less: Capital Lease Obligations	19,036				19,036
16						
17	Net Plant	19,993,454		(7,806)		19,985,648
18						
19	Allowance for Working Capital	1,249,328		0		1,249,328
20						
21						
22	Rate Base	$ 21,242,782		$ (7,806)		$ 21,234,976

(1) As the text and attachments of the ALJ's Proposal for Decision had noted differences, the Company is providing its Attachments A & B with the DTE Reply Brief as the starting position

(2) (3) Capital adjustments to Plant and Depreciation Reserve:

	Net Cap Ex	Plant Adj. (2)	Accum. Depr. (3)	
CONTINGENCY - Blue Water (CCGT)	$ (8,100)	$ (8,100)	$ (294)	(4)
	$ (8,100)	$ (8,100)	$ (294)	

(4) The Company agreed to concede on $8.1M of contingency associated with the Blue Water Energy Center during Reply Briefs which were not reflected in the associated documents

($000) Page 3 of 4

Line No.	(a) Description	(b) Reply Brief Position (1)	(c) Adjustments	(d) U-20836 DTE Exceptions Position
	Net Operating Income			
	Operating Revenues			
1	Sales Revenues	$ 5,080,523		$ 5,080,523
2	Other Operating Revenue	-		-
3	Fuel and Purchased Power	1,359,740		1,359,740
4	Net Margin	3,720,783	0	3,720,783
5				
6	**Operating Expenses**			
7	Operations and Maintenance Expenses	1,263,995		1,263,995
8	Depreciation and Amortization	1,086,116	(160) (2)	1,085,956
9	Property and Other Taxes	356,311		356,311
10	Total Operating Expenses	2,706,423	(160)	2,706,263
11				
12	**Operating Income**	1,014,360	160	1,014,520
13				
14	**Other Operating Income Adjustments**			
15	Allow. For Funds Used During Constr	44,400		44,400
16	Amortization of Loss on Reacquired Debt	(3,565)		(3,565)
17	Other (Income)/Deductions	158		158
18	Total Operating Income Adjustments	40,993	0	40,993
19				
20	**PreTax Net Operating Income**	$ 1,055,353	$ 160	$ 1,055,514
21				
22	**Federal Income Tax**	86,994	62	87,056
23	**State and Local Income Taxes**	55,536	10	55,546
24				
25	**Net Operating Income**	$ 912,824	$ 88	$ 912,912

(1) As the text and attachments of the ALJ's Proposal for Decision had noted differences, the Company is providing its Attachments A & B with the DTE Reply Brief as the starting position

(2) Depreciation and Amortization

CONTINGENCY - Blue Water (CCGT)	$ (160)	(3)
	$ (160)	

(3) The Company agreed to concede on $8.1M of contingency associated with the Blue Water Energy Center during Reply Briefs which were not reflected in the associated documents

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending October 31, 2023
Based on Average Rate Base
($000)

Line No.	Description	Amount ($000)		Percent	Cost %	Weighted Cost % (1)	Weighted Cost %		
	U-20836 Reply Brief (1)								
1	Long-Term Debt	$ 8,410,859	49.95%	39.55%	3.686%	1.841%	1.46%	1.0000	1.46%
2	Preferred Stock	0	0.00%	0.00%	0.000%	0.000%	0.00%		0.00%
3	Common Shareholders' Equity	8,426,264	50.05%	39.62%	10.250%	5.130%	4.06%	1.3496	5.48%
4	Total	16,837,123	100.00%			6.971%			
5									
6	Short-Term Debt	265,492		1.25%	1.739%		0.02%	1.0000	0.02%
7									
8	Other Interest Bearing Accounts	0		0.00%	1.739%		0.00%	1.0000	0.00%
9									
10	Job Development - ITC - Debt	23,688		0.11%	3.686%		0.00%	1.0000	0.00%
11	Job Development - ITC Equity	23,688		0.11%	10.250%		0.01%	1.3496	0.02%
12	Total Job Development - ITC	47,376							
13									
14	Deferred Income Taxes (Net)	4,117,952		19.36%	0.000%		0.00%		0.00%
15									
16	Total	21,267,944		100.00%			5.56%		6.98%
	U-20836 Exceptions to PFD								
17	Long-Term Debt	$ 8,410,859	49.95%	39.55%	3.686%	1.841%	1.46%	1.0000	1.46%
18	Preferred Stock	0	0.00%	0.00%	0.000%	0.000%	0.00%		0.00%
19	Common Shareholders' Equity	8,426,264	50.05%	39.62%	10.250%	5.130%	4.06%	1.3496	5.48%
20	Total	16,837,123	100.00%			6.971%			
21									
22	Short-Term Debt	265,492		1.25%	1.739%		0.02%	1.0000	0.02%
23									
24	Other Interest Bearing Accounts	0		0.00%	1.739%		0.00%	1.0000	0.00%
25									
26	Job Development - ITC - Debt	23,688		0.11%	3.686%		0.00%	1.0000	0.00%
27	Job Development - ITC Equity	23,688		0.11%	10.250%		0.01%	1.3496	0.02%
28	Total Job Development - ITC	47,376							
29									
30	Deferred Income Taxes (Net)	4,117,952		19.36%	0.000%		0.0000%		0.00%
31									
32	Total	21,267,944		100.00%			5.56%		6.98%

(1) As the text and attachments of the ALJ's Proposal for Decision had noted differences, the Company is providing its Attachments A & B with the DTE Reply Brief as the starting position

DTE Electric Company
Revenue Requirement Adjustments to Company's Filing
Projected 12 Month Period Ending October 31, 2023
($000)

MPSC Case No. U-20836
Exceptions to PFD
Attachment B

Line No.	(a) Description	(b) Source		(c) Revenue Deficiency
				(Pre Tax Amts)
1	**Company's Reply Brief Position (1)**	Exhibit A-11 Sch A-1		**$ 367,947**
2				
3	**Adjustments to Revenue Deficiency:**			
4				
5			Rate Base	
6	**Rate Base (2)**		Changes	
7	- Net Rate Base, Increase/(Decrease)	Attachment A page 2	(7,806)	(545)
8				
9			(7,806)	
10				
11				
12				
13	**Depreciation and Amortization**			
14	- Depreciation Expense, Increase/(Decrease)	Attachment A page 3		(160)
15				
16				
17	**Total Adjustments to Company's Initial Revenue Deficiency**	Line 6 through Line 26		$ (705)
18				
19	**Company's Exceptions to PFD**	Line 1 + Line 27		**$ 367,242**

(1) As the text and attachments of the ALJ's Proposal for Decision had noted differences, the Company is providing its Attachments A & B with the DTE Reply Brief as the starting position

(2) Rate Base Change multiplied by pre-tax return 6.98% (Attachment A page 4)

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-20836

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on October 5, 2022, she served a copy of DTE Electric Company's Exceptions to the Proposal for Decision in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

Estella R. Branson

Digitally signed by Estella R. Branson
Date: 2022.10.05 16:49:01 -04'00'

ESTELLA R. BRANSON

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