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July 26, 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 Initial Brief. Also attached is the Proof of Service.

Very truly yours,

Jon P. Christinidis

JPC/cdm
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
INITIAL BRIEF

Dated: July 26, 2022

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I. INTRODUCTION

This case began on January 21, 2022, when DTE Electric Company (DTE Electric or the Company) filed its Application (amended January 24, 2022) and supporting direct testimony and exhibits, requesting a jurisdictional rate increase of approximately \$388.2 million, and other forms of regulatory relief. The projected revenue deficiency spans the projected test year of November 1, 2022 through October 31, 2023 (Vangilder, 7T 2809, 2815; Exhibit A-11, Schedule A1, line 10).

DTE Electric supported its requested rate relief through its direct and rebuttal testimony and the exhibits filed in this case. The Company also provided extensive support through the information required by the Commission's Part III filing requirements as established in Case No. U-18238. DTE Electric's testimony and exhibits demonstrate that the Company needs rate relief for the projected test year to continue to provide safe and reliable electric service to the Company's customers. After reviewing Staff's and other intervenors' positions, DTE Electric is reducing its projected revenue deficiency to \$367.9 million to account for: a) changes to rate base (\$1.8 million) and associated depreciation expense (\$1.8 million); b) tree trim surge O&M savings (\$4.2 million); c) merchant fees reduction (\$3.0 million); d) pension expense (\$8.6 million); and e) time of use O&M (\$1.0 million). (See Company's Attachments A and B included with this Brief). Therefore, DTE Electric requests that the Commission authorize an adjustment of rates to provide an additional \$367.9 million annually.

II. HISTORY OF PROCEEDINGS

DTE Electric is presently serving its jurisdictional electric customers under rate schedules and charges approved by this Commission in, inter alia, its May 8, 2020 Order in Case No. U-20561.

On February 18, 2022, a pre-hearing conference was held and intervention was granted to the Michigan Attorney General (AG); the Association of Businesses Advocating Tariff Equity (ABATE); Bloom Energy Corp (Bloom); City of Ann Arbor (Ann Arbor); ChargePoint, Inc. (ChargePoint); Energy Michigan, Inc. (Energy Michigan or EM); EVgo Services, LLC (EVgo); Michigan Cable Telecommunications Association (MCTA); Michigan Energy Innovation Business Council (MEIBC); Institute for Energy Innovation (collectively MEIBC/IEI); Local 223, Utility Workers Union of America, AFL-CIO (UWUA or UWL 223); Great Lakes Renewable Energy Association (GLREA); Residential Customer Group (RCG); Wal-Mart, Inc. (Wal-Mart); the Kroger Company (Kroger); Gerdau MacSteel, Inc. (Gerdau); the Michigan Environmental Council (MEC), Natural Resource Defense Council (NRDC), the Sierra Club (SC) and the Citizens Utility Board of Michigan (CUB) (collectively MNSC); the Environmental Law & Policy Center, Ecology Center, and Vote Solar (collectively the Clean Energy Organizations or CEO); Michigan Municipal Association for Utility Issues (MI-MAUI); Souldarity and We Want Green, Too (collectively the Detroit Area Advocacy Organizations or DAAO); and Zeco Systems, Inc. (Zeco) (1T 11-12). On February 24, 2022, the ALJ granted International Transmission Company's (ITC) late petition to intervene.¹

¹ On March 1, 2022, the ALJ issued a Ruling Addressing Protective Order Disputes and an accompanying Protective Order. On March 15, 2022, the Company filed an Application and Brief for Leave to Appeal Ruling Addressing Protective Order Disputes and Protective Order. The Commission has not addressed the Application. The Company maintains its positions and reserves all rights in this regard.

Along with its Application, DTE Electric provided direct testimony and exhibits of 31 witnesses in support of its request for a rate increase and other regulatory relief. Maheen Asghar is a Principal Financial Analyst – Regulatory Economics (qualifications and direct testimony at 7T 1448-1459); Robert A. Bellini is the Manager of Community Lighting (qualifications and direct testimony at 7T 1707-1740); Shawn D. Burgdorf is the Manager of the Power Supply Strategy & Modeling team in DTE Electric’s Generation Optimization department (qualifications and direct testimony at 4T 113-139); Benjamin J.H. Burns is the Director of Electric Marketing and Electrification (qualifications and direct testimony at 7T 2399-2501); Michael S. Cooper is DTE Energy Corporate Services LLC’s Director of Compensation, Benefits & Wellness (qualifications and revised direct testimony at 7T 1779-1844); Adella F. Crozier is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 7T 2336-2371); Jeffrey C. Davis is DTE Electric’s Manager of Nuclear Strategy and Business Support (qualifications and direct testimony at 7T 2532-2574); Morgan Elliott Andahazy is the Director of the Advanced Distribution Management System (ADMS) project (qualifications and direct testimony at 7T 1486-1531); Keegan O. Farrell is the Manager of Demand Response (qualifications and direct testimony at 7T 1649-1698); Neal T. Foley is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 6T 1119-1186); Shannen M. Hartwick is the Director of Tree Trim (qualifications and direct testimony at 7T 2276-2331); Tamara D. Johnson is DTE Energy’s Director, Revenue Management and Protection (RM&P) (qualifications and direct testimony at 5T 801-825); Thomas W. Lacey is a Principal Financial Analyst in the Revenue Requirements Department of DTE Energy Corporate Services LLC’s Regulatory Affairs organization (qualifications and direct testimony at 7T 2588-2599); Robert J. Lee is DTE Energy’s Manager of Environmental Strategy (qualifications and direct testimony at

7T 1585-1598); Timothy J. Lepczyk is the Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and its subsidiaries, including DTE Electric (qualifications and direct testimony at 7T 1278-1295); Markus B. Leuker is DTE Electric's Manager of Corporate Energy Forecasting (qualifications and direct testimony at 7T 2610-2639); Habeeb J. Maroun is a Principal Financial Analyst in the Regulatory Requirements department of the Regulatory Affairs organization (qualifications and direct testimony at 6T 1024-1046); David C. Milo is a Fuel Resource Specialist in the Operations and Logistics group of the Company's Fuel Supply department (qualifications and direct testimony at 7T 2659-2669); Justin L. Morren is DTE Electric's Energy Supply Gas Plant Director (qualifications and direct testimony at 5T 627-724); Thac K. Nguyen is the Manager of Residential Programs and Pilots in the Energy Waste Reduction (EWR) group (qualifications and direct testimony at 7T 1600-1611); Sharon G. Pfeuffer is the Vice President of Distribution Operations Engineering and Construction (qualifications and direct testimony at 4T 223-399); Angie Pizzuti is DTE's Vice President and Chief Customer Officer (qualifications and direct testimony at 7T 2144-2247); Joseph E. Robinson is DTE Electric's Director, Central Engineering for Distribution (qualifications and direct testimony at 7T 1554-1582); Pankaj Sharma is the Director – Information Officer in the Revenue Requirements group of DTE Energy Corporate Services LLC's Information Technology Services (ITS) organization (qualifications and direct testimony at 7T 1922-2124); Phillip L. Smith DTE Electric's Director of Operational Technology for Distribution Operations (qualifications and direct testimony at 7T 1888-1912); Jason E. Sparks is the Director of Customer Services Organizations for DTE Energy Corporate Services LLC (qualifications and direct testimony at 7T 1613-1639); Theresa M. Uzenski is the Manager of Regulatory Accounting DTE Electric and DTE Gas Company (DTE Gas) (qualifications and direct testimony at 7T 2674-2772); Kirk M. Vangilder is a Principal

Financial Analyst for Revenue Requirements in DTE Energy's Regulatory Affairs organization (qualifications and direct testimony at 7T 2799-2815); Dr. Bente Villadsen is a Principal of The Brattle Group, which is an economic, environmental and management consulting firm (qualifications and direct testimony at 7T 1303-1394); Aaron Willis is Manager, Regulatory Economics (qualifications and direct testimony at 6T 914-965); and Sherri L. Wisniewski is DTE Energy's Director of Tax Operations (qualifications and direct testimony at 7T 1468-1483).

On May 19, 2022, the Commission Staff and Intervenors filed their testimony and exhibits. Staff provided the testimony of Anne T. Armstrong (8T 5484-5499), Paul R. Ausum (8T 5465-5473), Julie K. Baldwin (8T 5440-5455), Tayler Becker (8T 5393-5418), Elaina M. Braunschweig (8T 5268-5280), Marceline Alexandra Champion (8T 5321-5332), Jonathan J. DeCooman (8T 5287-5319), Roger A. Doherty (8T 5521-5531), Nicholas M. Evans (8T 5420-5438), Allan D. Freeman (8T 5533-5547), Daniel J. Gottschalk (8T 5103-5112), Lisa M. Kindschy (8T 5475-5482), Kevin S. Krause (8T 5501-5510), James E. LaPan (8T 5512-5519), Cody S. Mathews (7T 5373-5387), Theresa McMillan-Sepkoski (8T 5257-5266), Robert F. Nichols II, CPA (8T 5026-5037), Mark J. Pung (8T 5038-5052, 5063-5077), Nicholas M. Revere (8T 5122-5142), Danielle R. Rogers (8T 5334-5371), Shannon Rueckert (8T 5457-5463), Michelle L. Schreur (8T 5054-5061), Joseph E. Ufolla (8T 5079-5101), and Joy H. Wang, Ph.D. (8T 5164-5255).

ABATE provided the testimony of Brian C. Andrews (8T 2981-3005), James R. Dauphinais (8T 2888-2937), Christopher C. Walters (8T 3042-3115), and Jessica A. York (8T 3006-3041). The AG provided the testimony of Sebastian Coppola (8T 4739-4905) and David E. Dismukes (8T 4906-5023). Ann Arbor provided the testimony of Tiffany Giacobazzi (8T 3302-3305), Mathew Grocoff (8T 3306-3312), Julie Roth (8T 3387-3397), Dr. Mellissa Stults (8T 3314-3341), and Fang Wu (8T 3345-3386). Bloom provided the testimony of Douglas B. Jester (8T 4538-4558) and Peter

Morse (8T 4524-4537). CEO provided the testimony of Margarita Parra Cobaleda (8T 3551-3559), William D. Kenworthy (8T 3685-3714), Kevin Lucas (8T 3560-3646), and Dr. Guillermo Pereira (8T 3647-3684). ChargePoint provided the testimony of Mathew Deal (8T 4560-4597). DAAO provided the testimony of Brian Donovan (8T 4172-4203), Jackson Koeppel (8T 4255-4345), Gloria Lowe (8T 4145-4171), Stephanie Johnson (8T 4218-4254), and Eban Morales (8T 4204-4217). Energy Michigan provided the testimony of Alexander J. Zakem (8T 4484-4515). EVgo provided the testimony of Carine Dumit (8T 4677-4697). Gerdau provided the testimony of Jeffrey Pollock (8T 3721-3760). GLREA provided the testimony of Robert Rafson (8T 3253-3288), and John Richter (8T 3124-3252). ITC provided the testimony of Kwafɔ Adarkwa (8T 4624-4627, 4640) and John Kopinski (8T 4628-4639). Kroger provided the testimony of Justin Bieber (8T 4642-4654). MEIBC/IBI provided the testimony of Justin R. Barnes (8T 4419-4482) and Dr. Laura S. Sherman (8T 4370-4418). MEC/CUB provided the testimony of David J. Garrett (8T 3863-3942), and with NRDC/SC, Tyler Comings (8T 4041-4084), Douglas B. Jester (8T 3765-3862), Chris Neme (8T 4085-4114), and Robert G. Ozar, P.E. (8T 3952-4040). MI-MAUI provided the testimony of Rhonda Bouma (8T 3402-3408), Richard Bunch (8T 3409-3482), Joseph Gacloch (8T 3485-3488), Raymond Hess (8T 3489-3504), James Krizon (8T 3510-3515), Thomas Lyon (8T 3516-3531), Thomas Power (8T 3532-3538), and Sue Shink (8T 3539-3547). UWUA provided the testimony of Dennis Smith (8T 3118-3121). Wal-Mart provided the testimony of Lisa V. Perry (8T 4117-4141).

On June 13, 2022, DTE Electric filed the rebuttal testimony and exhibits of witnesses Asghar (7T 1460-1465), Bellini (7T 1741-1776), Burgdorf (4T 140-151), Burns (7T 2502-2529), Cooper (7T 1845-1885), Crozier (7T 2372-2396), Davis (7T 2575-2586), Elliott Andahazy (7T 1532-1552), Farrell (7T 1699-1704), Foley (6T 1187-1233), Hartwick (7T 2332-2334), Johnson

(5T 826-838), Lacey (7T 826-838), Lepczyk (7T 1296-1299), Leuker (7T 2640-2657), Maroun (6T 1047-1070), Morren (5T 725-763), Pfeuffer (4T 400-536), Pizzuti (7T 2248-2273), Sharma (7T 2125-2146), Smith (7T 1913-1918), Uzenski (7T 2773-2796), Villadsen (7T 1395-1445), and Willis (6T 966-1004).

Staff filed the rebuttal testimony of witnesses Braunschweig (8T 5281-5285), Freeman (8T 5548-5550), Gottschalk (8T 5113-5120), Krause (8T 5510-A to 5510-L), Mathews (8T 5388-5391), and Revere (8T 5143-5162).

Ann Arbor filed the rebuttal testimony of witness Stults (8T 3342-3344). ABATE filed the rebuttal testimony of witness Dauphinais (8T 2938-2980). ChargePoint filed the rebuttal testimony of witness Deal (8T 4598-4621). DAAO filed the rebuttal testimony of witness Koepfel (8T 4346-4367). Energy Michigan filed the rebuttal testimony of witness Zakem (8T 4516-4522). EVgo filed the rebuttal testimony of witness Dumit (8T 4698-4712). GLREA filed the rebuttal testimony of witness Rafson (8T 3289-3295). Kroger filed the rebuttal testimony of witness Bieber (8T 4655-4674). MNSC filed the rebuttal testimony of witness Jester (8T 4114-A to 4114-H). Zeco filed the rebuttal testimony of Thomas Ashley (8T 4715-4729).

Also, on June 13, 2022, MI-MAUI filed the supplemental direct testimony of witness Hess (8T 3505-3509).

Cross-examination and binding-in of testimony was held on June 29-30, and July 1, 5, and 7, 2022. The public record consists of 5,574 pages of public transcript (numbered to 5554 and including 8T 4114-A to 4114-H, and 5510-A to 5510-L), and continues with a confidential record (8T 5555-5696), and a multitude of exhibits.

III. SUMMARY OF MAJOR ISSUES

DTE Electric's requested rate increase is required to recover the costs associated with significant investments in distribution, generation, and customer service. Several of these programs include strategic investments in electric distribution assets to modernize equipment, support growth in customer demand in specific areas, improve worker and public safety, and reduce the frequency and duration of power outages. The Company's requested relief also includes changes to certain tariffs, various accounting proposals, and several proposed pilot programs associated with its distribution system, generation, electric vehicles (EVs) and demand response (DR).

DTE Electric initially requested that the Commission authorize an adjustment of rates to provide an additional \$388.2 million annually (Vangilder, 7T 2809, 2815; Exhibit A-11, Schedule A1, line 10), based on \$21.3 billion in rate base and adjusted NOI of \$899.2 million. As discussed in section I above, DTE Electric has adjusted its request to \$367.9 million. The revenue deficiency is largely driven by the revenue requirement associated with increased investments in plant involving generation and the electric distribution system, and associated depreciation and property tax increases, and offset in part by lower operation and maintenance (O&M) expenses. The Company is seeking a return on equity (ROE) of 10.25%, and uses inflation factors of 3.1% for 2021, 2.4% for 2022, and 2.4% for January 1 through October 31, 2023.

IV. JURISDICTION, STANDARD OF REVIEW AND RATE SETTING LAW

A. Jurisdiction and Standard of Review

The Commission has jurisdiction over this case pursuant to 1909 PA 106, as amended, MCL 460.551 *et seq.*; 1909 PA 300, as amended, MCL 462.2 *et seq.*; 1919 PA 419, as amended, MCL 460.51 *et seq.*; 1939 PA 3, as amended, MCL 460.1 *et seq.*; 1969 PA 306, as amended, MCL 24.201 *et seq.*; and the Commission's Rules of Practice and Procedure, as amended, R 472.10401 *et seq.*

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.” *Monroe v State Employees’ Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011). 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, even if other experts disagree. *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

The preponderance of evidence standard applies in this proceeding. *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 evidence standard is the lightest of all evidentiary standards when compared to the heightened “clear and convincing” standard² or the “beyond a reasonable doubt” standard that is only applicable to criminal proceedings.³ 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).]

DTE Electric has the initial burden to prove its case by a preponderance of the evidence. “[O]nce 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

² *In re Moss*, 301 Mich App 76, 89-90; 836 NW2d 182 (2013).

³ *Thangavelu v Dep’t of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986).

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 in support of its position. [January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

The Administrative Procedures Act (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 within the agency’s specialized expertise.” Noncompliance with the APA is reversible error. *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

The ability to take official notice is limited under applicable rules.⁴ See also *Freed v Salas*, 286 Mich App 300, 341; 780 NW2d 844 (2009), where the Court of Appeals affirmed the trial

⁴ Rule 428 of the Commission’s Rules of Practice and Procedure provides:

Except as otherwise provided by law, the commission and the presiding officer **may take official notice of judicially cognizable facts and may take notice of general, technical, or scientific facts within the commission’s specialized knowledge**. The commission or the presiding officer shall notify the parties at the earliest practicable time of any noticed fact that pertains to a materially disputed

court’s refusal to take judicial notice of a speed limit, explaining in part: “Given that the signage and the traffic control order did not agree as to the speed limit for the area, the fact could not reasonably be said to have been undisputed or capable of accurate and ready determination.”

The Commission recently explained that “because of the unforgiving time limits under MCL 460.6a [which at that time had a 12-month deadline], official notice requests, especially those that may generate controversy regarding the materiality or weight of the evidence proffered, can rarely, if ever, be entertained after the close of the record” (December 11, 2015 Order in Case No. U-17767, p 136, agreeing with ALJ’s denial of official notice request).

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained that “[t]he 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. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994).

It is similarly well established that 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

issue that is being adjudicated and, on timely request, the parties shall be given an opportunity before the final decision to dispute the fact or its materiality. The commission may use its expertise, technical competence, and specialized knowledge in the valuation of evidence presented to it.” [R 792.10428. Emphasis added.]

MRE 201(b) similarly provides:

A judicially noticed fact must be one not subject to reasonable dispute in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned. (Emphasis added).

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).

B. Rate Setting Legal Requirements

In addition to the discussion above, utilities also have 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.⁵

The Michigan Supreme Court has provided further guidance that the Commission must use in setting DTE Electric’s rates. Specifically, creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates in *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973) (“Certainly at first blush it would appear to anyone steeped in ‘due process’ considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost.”)

⁵ 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).

As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service.⁶ It is axiomatic that utility rates are overall rates. *Federal Power Comm, supra*, 320 US at 602; *Michigan Bell Telephone Co v Public Service Comm*, 332 Mich 7, 37; 50 NW2d 826 (1952); MCL 460.6a(2)(b).

DTE Electric's constitutional rights would be violated by a failure to acknowledge (and establish rates based on) both decreasing and increasing costs. The United States Supreme Court, in construing the Fifth Amendment mandates in conjunction with utility ratemaking, aptly concluded:

Regulation may, consistently with the Constitution, limit stringently the return recovered on investment, for investors' interests provide only one of the variables in the constitutional calculus of reasonableness (citations omitted). It is, however, plain that the 'power to regulate is not a power to destroy,' (citations omitted) and that maximum rates must be calculated for a regulated class in conformity with the pertinent constitutional limitations. Price control is "unconstitutional if arbitrary, discriminatory, or demonstrably irrelevant to the policy the legislature is free to adopt." [*Permian Basin Area Rate Cases, supra*, 390 US at 769-770 (Emphasis added).]

The Commission has an obligation to facilitate DTE Electric's financial health for the benefit of its electric customers and shareholders. *See, by way of example and not limitation*, MCL 460.6j(1); MCL 460.10(b); *Smith v Illinois Bell Telephone Co*, 270 US 587, 591; 46 S Ct 408; 70 L Ed 747 (1926). *Federal Power Comm, supra*, 320 US at 602; *Michigan Bell Telephone Co, supra*, 332 Mich at 37; *MichCon, supra*, 389 Mich at 633; *Michigan Bell Telephone Co v Engler*, 257 F3d 587, 594-96 (CA 6, 2001). Furthermore, our Supreme Court has clearly stated that:

Statutes will be construed in the most beneficial way which their language will permit to prevent absurdity, hardship or injustice; to favor public convenience, and

⁶ 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).

to oppose all prejudice to public interests. [*Attorney General v Marx*, 203 Mich 331, 335; 168 NW 1005 (1918).]

Under well-established ratemaking law, rates for utility service are set prospectively so that the utility provides service and its customers receive service at established rates, which are based on the estimated costs of providing that service, plus a reasonable return on the utility's investment. *ABATE v Public Service Comm*, 208 Mich App 248, 257-258; 527 NW2d 533 (1994). This is part of the "regulatory compact," under which the utility dedicates its private property to serve the public, and correspondingly receives a reasonable return on the value of its private property. In *Board of Public Utility Comm'rs v New York Telephone Co*, 271 US 23; 46 S Ct 363; 70 L Ed 808 (1926), the United States Supreme Court explained that the just compensation safeguarded to the utility by the Fourteenth Amendment is a reasonable return on the value of the property used at the time that the property is being used for the public service. Rates that are not sufficient to yield that present return are confiscatory. 271 US at 31. To the extent that the utility might have earned sufficient revenue in the past, such past revenue cannot be used to sustain confiscatory rates in the future. *Id.* at 32. Thus, it would be unconstitutional for the Commission to use hindsight or otherwise base DTE Electric's rates on past events.

The Michigan Supreme Court has recognized that the Commission has only limited statutory authority, which does not include the authority to retroactively reduce rates. *Michigan Bell Telephone Co v Public Service Comm*, 315 Mich 533, 347; 24 NW2d 200 (1946). A lawfully established rate remains in force until altered by a subsequently established lawful rate. *Id.*, at 544. A regulatory body cannot penalize a utility for collecting a rate during the period elapsing between the date of the order prescribing the rate and the date of the subsequent order reducing it. *Id.* at 543-44. Where the Commission establishes a reasonable rate in its legislative capacity, the

Commission cannot later, in its quasi-judicial capacity, find that the utility violated the law because it charged that rate. *Id.* at 550-51.

The prohibition against retroactive ratemaking remains in effect and applies in this case so that rates may only be set prospectively. “[T]he essential principal of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones.” *The Detroit Edison Co v Public Service Comm*, 416 Mich 510, 523; 331 NW2d 159 (1982) (opinion by Fitzgerald, C.J.).

V. TEST YEAR

DTE Electric’s projected test year is November 1, 2022 through October 31, 2023. The Company normalized and adjusted actual results from the historical test year ended December 31, 2020 to arrive at its filed projected revenue deficiency of approximately \$388.2 million (Vangilder, 7T 2809, 2815; Exhibit A-11, Schedule A1, line 10) (adjusted to \$367.9 million in this Brief, see Attachments A and B) which produced the equivalent of a fully projected test year.

The only disagreement was by ABATE witness Dauphinais, who suggested policy arguments against projected test years and that the Commission is not required to set rates using a projected test year (8T 2895-2902). But MCL 460.6a(1) plainly states: “A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges.” And the November 1, 2022 – October 31, 2023 test year in this case is plainly a “consecutive 12-month period.” The Commission recognized MCL 460.6a(1)’s plain language in DTE Electric’s last two rate cases (U-20162 and U-20561), most recently explaining in part:

The statute contains no limitation on the future consecutive 12-month period, no requirement to use an historical test year, and no information or limitation regarding

the relationship between the date of the application and the test year. The test year may be in the future, and the 12 months must be consecutive; those are the requirements of the statute. [May 8, 2020 Order in Case No. U-20561, p 11.]

RCG appealed from this decision, seeking to deviate from the plain statutory language, but the Court of Appeals affirmed, and our Supreme Court declined to hear the case. *In re Application of DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued December 21, 2021 (Docket No. U-353767), *lv den* 974 NW2d 192 (May 31, 2022). ⁷

ABATE witness Dauphinais further asserted that “the use of a projected test year allows DTE to begin recovery of costs before those costs have been verified as being real and prudently incurred” (8T 2896). This policy argument lacks merit and relevance in light of MCL 460.6a(1)’s plain statutory language and the requirement that the courts and the Commission ⁸ must apply that plain language, regardless of ABATE’s disagreement with how our Legislature wrote it.

The Company also verified its projected costs, as evidenced for example by over 1,600 pages of direct testimony, over 2,700 pages of exhibits, and responses to over 5,600 audit and discovery requests. Also, since base rates are set for a future twelve-month period and new rates cannot be implemented until a final order is issued, it makes sense for a projected test year to begin at or about the time that a final order is expected (Crozier, 7T 2388-2389).

Therefore, ABATE’s argument against projected test years should be rejected because it (1) is contrary to plain statutory language, (2) simply rehashes policy arguments that have been repeatedly rejected, and (3) is refuted by the massive record in this case (along with DTE Electric’s

⁷ The Commission reached a similar conclusion in Case No. U-20162. The Court of Appeals affirmed and denied rehearing, and our Supreme Court similarly denied RCG’s application for leave to appeal and reconsideration. *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 25, 2021 (Docket Nos. 349924 and 350008), *recon den* (April 19, 2021) *lv den* (November 2, 2021), *recon den* (January 31, 2022).

⁸ *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008) (“agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature”).

additional thousands of responses to audit and discovery requests) verifying the Company's projected costs.

VI. RATE BASE

A utility's rate base consists of the net amount of capital invested in plant, plus the utility's working capital requirements. DTE Electric's initially-filed rate base for the projected test year ending October 31, 2023 was \$21.268 billion, which consisted of \$20.011 billion of net plant, and \$1.257 billion of working capital (Vangilder, 7T 2809; Exhibit A-12, Schedule B1, column (d)).

As discussed in Section I, the Company has made a few adjustments to its originally filed Rate Base. Adjustments to working capital include: 1) other accounts receivable of \$8.1 million. Adjustments to net plant include: 1) \$13.2 million of capital expenditures related to Time of Use (rate base impact of \$10.7 million); 2) \$4.5 million of capital expenditures related to the Wixom Pole Yard (rate base impact of \$2.9 million); 3) \$2.5 million of capital expenditures related to DERMS Implementation (rate base impact of \$1.8 million); 4) \$0.7 million of capital expenditures related to Energy Center HQ (rate base impact of \$0.6 million); 5) \$0.6 million of capital expenditures related to Enterprise Automation (rate base impact of \$0.4 million); and 6) \$1.5 million of capital expenditures related to miscellaneous IT projects that lacked business cases (rate base impact of \$0.7 million). DTE Electric's Total Rate Base request as adjusted in this Brief for the projected period ending October 31, 2023 is \$21.243 billion, which consisted of \$19.994 billion of net plant and \$1.249 billion of working capital.

A. Working Capital

As indicated above, DTE Electric supported a projected working capital amount of \$1,257 million (Exhibit A-12, Schedule B4). Company witness Uzenski supports the derivation of the working capital amount through her testimony supporting the forecasted balance sheet. (7 T 2742)

Other Accounts Receivable had an embedded balance that is considered non-recoverable and non-utility related. Staff proposed removing \$8.1 million from working capital (8 T 5060). In this Brief, the Company accepts Staff's \$8.1 million working capital adjustment.

In its Order in the Company's last rate case, the Commission rejected ABATE's proposal to exclude the prepaid pension asset from working capital but stated that "in DTE Electric's next general electric rate case, the Commission expects the parties to provide a robust and fully developed record that provides specific evidence of the funding source for the prepaid pension asset that may assist the Commission in evaluating the propriety of including the prepaid pension asset (or liability) in rate base" (May 8, 2020 Order in Case No. U-20561, pp 162-63).

Accordingly, Company accounting expert Uzenski (who previously testified on this topic) provided a detailed explanation of the amount of the prepaid pension asset, showed how it is funded by investors, and why it is a reasonable and prudent investment. (7T 2748-2759). No party has objected to the inclusion of the prepaid pension asset in working capital in this proceeding.

Based on the acceptance of Staff's adjustment and no other issues with the Company's proposed working capital amount, DTE Electric supports a \$1.249 billion working capital balance.

B. Capital Expenditures

DTE Electric has made or will make approximately \$6.6 billion of capital expenditures from the end of the historical test year to the end of the projected test year (January 1, 2021 through October 31, 2023) (Exhibit A-12, Schedule B5, line 1 columns (e) and (f)). These expenditures should be approved because they are reasonable and prudent investments in DTE Electric's system and are necessary for DTE Electric to maintain its safe and reliable system for generating and distributing electric to its customers.

1. Energy Supply

Company witness Morren explained and supported total Energy Supply⁹ 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 with legal and regulatory requirements until their 2021 and 2022 retirements (Morren, 5T 632, 647).

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

⁹ 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).

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 disagrees because the AG is effectively proposing to create a new and unreasonable standard for approval of project funding that spans well beyond the relevant timeframe in this case. 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. The AG's attempt to pass judgment on future project funding that the Company is not requesting in this case should be disregarded (Morren, 5T 729-734).¹⁰ The Company also incorporates its discussion in section V regarding the projected test year.

The AG's proposed disallowance should also be rejected because it is based on an incorrect understanding of the projects' approval status. Mr. Coppola based his proposed disallowance only on 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 (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

¹⁰ Mr. Coppola's \$18.3 million recommended disallowance on line 7 of Exhibit AG-1.14 should also be 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).

environmental (\$18.5 million); and (3) Tier II decommissioning (\$99.1 million) as further discussed below (5T 731-732).

For routine capital, 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 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 should be disregarded as factually incorrect. The remaining \$0.8 million concerns the Monroe Unit 3 Waterwall project, which is anticipated to receive an executed CARF in June 2022 so it should not be disallowed (Morren, 5T 732-733).

Similarly, Exhibit AG-1.14, lines 1-3, indicates an \$18.5 million disallowance for three ongoing environmental projects at the Monroe Power Plant. As further discussed below, 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). 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 based on a timeframe beyond this case (Morren, 5T 733-734; Exhibit A-40, Schedule EE1).

The AG's proposed disallowance associated with the decommissioning of the River Rouge, St. Clair, and Trenton Channel Power Plants should similarly be rejected because Company management has approved \$9.5 million, \$9.5 million, and \$9.7 million for their 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 apparently 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).

AG witness Coppola also proposed a full (\$47.6 million) disallowance of the Company's BlackStart infrastructure improvements¹¹ 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).

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

¹¹ 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).

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).

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).

Therefore, the Commission should reject the AG's proposed disallowance, 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).

MNSC witness Comings proposed \$48.8 million of capital expenditure disallowances associated with four routine capital projects at Monroe Power Plant: (1) \$8.6 million for the Monroe Main Unit Transformer (MUT); (2) \$21.1 million for the Monroe Unit 1 LPA & LPB Turbine Rotor & Blades; (3) \$18.0 million for the Monroe Unit 1 Waterwall Tubes; and (4) \$1.0 million for the Monroe Unit 3 Waterwall Tubes (8T 4078). The Company disagrees because MNSC's proposal is based on erroneous customer payback calculations and neglects the need for the projects to maintain safe and reliable power plant operations (Morren, 5T 755-760).

More specifically, there are at least three critical flaws in Mr. Comings' underlying reasoning. First, he reasoned that internal rate of return (IRR) analyses showed no net benefit until 2040, and the plant might retire before then (Comings, 8T 4077). This is wrong because he chose the wrong set of Company data. His calculations essentially determine how long it takes the Company to recover its capital investments through depreciation rates, and do not include customer benefits such as avoidable PSCR and O&M costs. Customer payback periods are far shorter than Mr. Comings calculated, ranging from 5.2 to 6.8 years (Morren, 5T 756-757).¹²

Second, the MUT is a critical spare for the generation fleet, and can be utilized at multiple power plants to avoid the risk of an outage lasting 18-24 months while a replacement transformer can be procured, manufactured, shipped and installed. This is further supported by the recent example of a 2021 main unit transformer failure on Monroe Unit 1. The Company's critical spare was transported from its secure storage site and installed, reducing the 18-24 month potential outage to just 2 months. The critical spare did its job and now needs to be replaced (Morren, 5T 759).

Third, the two waterwall tube replacement projects are important to the Company and its customers because waterwall tube leaks are a major cause of boiler unreliability, leading to unit outages that increase energy, capacity, and O&M costs for customers. The Company has been methodically replacing portions of Monroe's waterwalls that are at most risk of failure during each major periodic outage (once every four years) to maintain boiler reliability. As indicated above, there is a net benefit to customers by mid-2028. Therefore, MNSC's proposed disallowance should be rejected (Morren, 5T 760).

¹² There is no customer payback period for the Monroe Unit 1 LPA & LPB Turbine Rotor & Blades project because it is safety-based. The work is required to continue safely operating the unit beyond its next major outage. Not performing the project in a timely manner would put the LP turbines at significant risk of catastrophic failure, which could require an outage of more than a year for recovery, and would potentially cause serious collateral damage to Company personnel and equipment in the plant (Morren, 5T 689-690, 758-759).

Staff did not recommend any adjustments to routine capital projects (Champion, 8T 5330). Staff did, however, recommend the combined disallowance of approximately \$76 million for removal projects that are above the amounts previously approved for inclusion in depreciation rates (DeCooman, 8T 5300-5301; LaPan, 8T 5518-5519),¹³ and that any reasonably and prudently incurred removal costs be deferred with a full return of and on the deferred amount (Nichols, 8T 5037). The Company disagrees because Staff's proposal diverges from normal ratemaking and accounting principles. Staff also did not take issue with the substance of the projects or indicate that they are unnecessary (Morren, 5T 763; Crozier 7T 2375-2379).

Company witness Crozier further explained that Staff's reliance on the settlement agreement in Case No. U-18150 is misplaced because that settlement agreement provided for a requirement to provide cost removal bids only for the Tier 2 plants (December 6, 2018 Order in Case No. U-18150, Exhibit A, p 2, paragraph 5: "require future removal costs for the Tier 2 Plants, when the removal costs are incurred, to be reconciled after firm removal costs bids are accepted and reviewed by Staff and ABATE"). The Tier 2 plants were defined as "Trenton Channel, St. Clair and River Rouge." Staff has expanded the scope of this provision to include Tier 1 (Belle River and Monroe) and other plants, which was never agreed to or ordered in Case No. U-18150. It is well established that "[a]n agreement to settle a pending lawsuit is a contract, governed by the legal rules applicable to the construction and interpretation of other contracts," including that language is enforced as written.¹⁴ Therefore, Staff's improperly-expansive reading (or any suggestion that the

¹³ The proposed adjustments are \$6.7 million, \$10.2 million, \$24.7 million, and \$34.9 million for the Monroe Bottom Ash Basin Closure (CCR), Conners Creek Decommissioning / Sea Wall, River Rouge Decommissioning, and Trenton Channel Decommissioning projects.

¹⁴ *Reiter v SET Enterprises, Inc*, 283 Mich App 657, 663, 665; 770 NW2d 902 (2009).

settlement agreement should be retroactively modified, without the Company's agreement or the Commission's approval), is inappropriate (Crozier, 7T 2376-2378).

Staff's proposal to defer these removal costs with a full return for inclusion in a future rate case is also inappropriate because the existing regulatory standard and appropriate ratemaking treatment is to include the reasonably and prudently incurred and projected removal costs in base rates.¹⁵ Staff provided no evidence that the projected capital expenditures for the removal projects are unreasonable or imprudent. Instead, Staff essentially proposes a new regulatory and ratemaking standard that removal costs can only be set in a depreciation case, and any amounts projected in a general rate case above that previously estimated level should be deferred. Moreover, Staff's proposal would result in unjust and unreasonable regulatory lag because there could be a multi-year gap between an order in a depreciation case establishing projected removal costs, and the inclusion of those costs in a general rate case (Crozier, 7T 2378-2379; Uzenski, 7T 2789).

Company witness Uzenski further explained that Staff's proposal for regulatory asset treatment is inconsistent with utility plant accounting, and that the Company would not be able to recognize the equity return in net income for SEC purposes until recovery in rates is provided, per Accounting Standard Codification 890-340-25 (7T 2789).

As an alternative, the Company proposes to include the costs in rates in this case, but subject to a refund. Specifically, should any actual expenditures ultimately be found to be imprudent and permanently disallowed for these specific projects, the Company would write-off the disallowed

¹⁵ Furthermore, as witness Crozier explained, the "referenced provision of the settlement agreement was intended to facilitate a transparent exchange of information by providing Staff and ABATE the opportunity to reconcile *incurred removal costs* against firm *removal cost bids* for the Tier 2 plants." It was not intended to grant Staff and/or ABATE the ability to pre-determine what projected costs and spending levels are appropriate to be included in this rate case. This is made plain as the settlement agreement also provides that "*the Parties also agree that expenditures and removal costs associated with DTE Electric's Tier 2 coal plants continue to be recoverable from traditional depreciation and other forms of recovery.*" (Crozier, 7T 2377-2378)

costs and record a regulatory liability for the “return on” the costs included in base rates for refund to customers (Crozier, 7T 2379-2380; Uzenski, 2789).

In summary, the projected capital projects and associated expenditures for the Company’s Energy Supply units are required to support safety, regulatory compliance, environmental compliance, and reliability. Therefore, the Company’s capital expense recovery should be fully approved. To the extent that the Commission considers Staff’s proposal to defer removal costs, the Commission should not deviate from the U-18150 settlement agreement or established accounting and ratemaking treatment, but instead consider the Company’s alternative proposal. Further details are presented below in the context of specific topics.

i. Actions in Response to 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).

The Company has two options to achieve compliance for BATW and FGD wastewater: (1) design and engineer new technologies that are compliant with ELG requirements; or (2) pursue a compliance subcategory, one of which is to cease coal-burning activities, including either retiring the coal-fired unit(s), or converting the unit(s) to other fuels by December 31, 2028, in which case the existing standard limits already in effect for BATW and FGD wastewater discharges would remain in effect (Lee, 7T 1590-1591).

In addition to the cease-coal-burning subcategory, the Reconsideration Rule also established Best Available Technology (BAT) standard discharge limits for FGD wastewater and finalized a Voluntary Incentive Program (VIP) subcategory. Under the VIP, companies may choose to meet more stringent effluent limits established by the EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chooses the VIP option, then the applicability date for FGD wastewater compliance will be December 31, 2028 (Lee, 7T 1591).

To establish compliance for either of the above-described subcategories, companies were required to submit a Notice of Planned Participation (NOPP) to the state permitting agency by October 13, 2021. Accordingly, on October 13, 2021, DTE Electric submitted NOPPs 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 VIP at the Monroe Power Plant for FGD wastewater compliance (Morren, 5T 633-635; Lee, 7T 1591-1593). The ELG Rule does not affect the Tier 2 plants as the River Rouge Power Plant retired in 2021, and the St. Clair and Trenton Channel Power plants will retire in 2022 (Lee, 7T 1594).

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).¹⁶

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). To the contrary, multiple documents show that witness York'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. Therefore, ABATE's proposed disallowance should be rejected (Morren, 5T 744).

The Monroe Power Plant provides essential support to the local and regional electrical grids because of its size, location, and operating characteristics.¹⁷ Therefore, the Company is proceeding with 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 will allow the plant to continue operating beyond 2023.¹⁸ The Company will achieve BATW wastewater ELG compliance by the

¹⁶ At the Belle River Power Plant, fly ash is currently collected dry, so there are no FATW implications. The power plant was also constructed and operates without FGDs, so there is no FGD wastewater. The bottom ash is currently collected using transport water, however, and the ELG Reconsideration rule requires the Company to achieve compliance with BATW discharge requirements (Lee, 7T 1593).

¹⁷ 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).

¹⁸ 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).

end of 2025.¹⁹ 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). The Company disagrees based on the record. 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. Therefore, ABATE's proposed disallowance should be rejected (Morren, 5T 745-746).

MNSC witness Comings proposed \$16.9 million of capital expenditure disallowances associated with the Monroe Bottom Ash Conversion (ELG) (\$15.1 million) and FGD Wastewater (ELG) (\$1.8 million) projects based on his opinion that these expenditures are avoidable under a 2028 retirement (Exhibit MEC-73). The Company disagrees because MNSC's proposition that

¹⁹ 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).

capital expenditures for environmental compliance are avoidable is not permitted by the ELG rules. As discussed above, the Company determined that the reasonable and prudent course of action was to proceed with ELG compliance by installing environmental upgrades (Morren, 5T 645-647). This rate case includes only a portion of these ELG implementation costs, but they are critical to ensure that the Company can stay on track with the compliance schedule set forth by state and federal regulators (Morren, 5T 753-754).

Furthermore, the potential that the ELG rule might change does not affect the Company's need to comply with the existing rule, and corresponding need to move forward. For example, the EPA's Notice of rulemaking initiative states that the "EPA expects permitting authorities to continue to implement the current regulations while the Agency undertakes a new rulemaking" (Exhibit A-40, Schedule EE9). The law has not changed, and one can only speculate that it might change at some time in the future.²⁰ EGLE is currently preparing to issue a new wastewater discharge permit for Monroe Power Plant that incorporates deadlines for FGD and BATW compliance projects as dictated in the 2020 ELG rules. It is critical that the Company initiates the testing and evaluation of alternative technologies so that a preferred technology can be installed by the required deadline (Morren, 5T 652, 754).

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

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

²⁰ 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).

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).²¹ 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).

²¹ 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).

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) 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.”

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).

Mr. Morren, who was previously the director of the Belle River Power Plant and therefore 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).

MNSC witness Comings proposed a \$2.4 million disallowance for the Belle River Fuel Conversion Engineering project based on the Company not having made a decision to convert the plant from coal to natural gas-fired operations (8T 4069). The Company disagrees because 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 has no basis for its proposal. The project is also 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. Therefore, MNSC's proposed disallowance should be rejected (Morren, 5T 752).

MSNC witness Comings also 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.]

Mr. Comings further asserted 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.²² 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).

²² Exhibit A-033, Schedule X2 reflects some recent DTE Electric experiences with renewable project delays (Burgdorf, 4T 148).

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.]²³

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).

MNSC witness Comings also asserted that five projects (totaling \$12.8 million) should be disallowed as allegedly avoidable because the Belle River Power plant might retire in 2026

²³ 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 Mr. Burgdorf's original Table 5 "likely understate[d] the reliability risk" (8T 4636).

(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).

iii. Coal Combustion Residuals (CCR) Expenditures

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, 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 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 Company disagrees because 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 required closure of the Monroe Bottom Ash Basin. Therefore, ABATE's proposed disallowance 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 Company disagrees because, again, ABATE's proposal is 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 criticism is 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 ABATE's proposed disallowance should be rejected (Morren, 5T 654, 748-749).

iv. Hydrogen Fuel System Pilot and Slocum BESS Pilot

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

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

More specifically, 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 (Morren, 5T 659). Mr. Morren also provided additional testimony on these topics and supporting the pilot (5T 659-667).

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). The Company disagrees because 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 proposed disallowance should be rejected as unfounded (Morren, 5T 741-742).²⁴

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

²⁴ Witness York and other Intervenors also unreasonably gave little weight to numerous factors favoring the pilot (Morren, 5T 743).

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 (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 disagreed, 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) than the Company requests in this case (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),²⁵ and MEIBC/IEI witness Sherman acknowledged the valuable learnings and experience that the Company can gain from this pilot (8T 4399). Therefore, the Commission should reject the AG's proposed disallowance (Morren, 5T 737-738).

²⁵ Staff 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 has received management approval for \$38 million (Exhibit A-40, Schedule EE3 and EE4), so Staff's concern has been addressed (see also 5T Morren, 761-762).

2. Fuel Supply and Midwest Energy Resources Company

Mr. Milo supported DTE Electric's Fuel Supply and Midwest Energy Resources Company (MERC) capital expenditures for 2020 through the projected period ending October 31, 2023. The capital expenditures of \$3.7 million for 2020, \$4.8 million for January 2021 through October 2022, and \$2.5 million for the projected 12-month period ending October 31, 2023 (as shown on Exhibit A-12, Schedule B5.2), relate to improving safety, meeting environmental requirements, reliable operations, and/or replacement of end-of-life equipment. The capital expenditures are reasonable and prudent, and necessary to maintain and/or improve Fuel Supply operations and MERC's coal transshipment capabilities (Milo, 7T 2663, 2665-2668; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)). Therefore, the expenditures should be approved.

3. 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 Nuclear Regulatory Commission (NRC) has licensed Fermi 2 to operate through 2045. The capital expenditures (and O&M expenses discussed elsewhere) that Mr. Davis discussed throughout his testimony reflect reasonable and prudent measures to ensure the safe and reliable extended operation of Fermi 2 (Davis, 7T 2536, 2537, 2574).

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 year (Davis, 7T 2537-2538; Exhibit A-12, Schedule B5.3, page 1, line 11, columns (e) and (f)).

Routine and Small Projects (summarized on page 1, line 2, and listed on pages 2 and 3 of Exhibit A-12, Schedule B5.3) are routine maintenance and smaller-scale project capital expenditures associated with maintaining Fermi 2's various assets (Davis, 7T 2540-2541). For

example, Mr. Davis discussed the Visual Annunciator System (VAR) Replacement project, and the Security video server system computer replacement project (7T 2542-2543; Exhibit A-12, Schedule B5.3, page 2, lines 11 and 50).

Non-routine and Large Projects (summarized on page 1, line 3, and further detailed on page 4 of Exhibit A-12, Schedule B5.3) are large capital projects that are necessary to maintain Fermi 2, and beyond normal routine capital expenditures (Davis, 7T 2543). For example, the Main Unit Generator projects are necessary to address both an Original Equipment Manufacturer (OEM) design vulnerability and overall reliability, and thereby support Fermi 2's reliable operation through 2045 (Davis, 7T 2547-2551; Exhibit A-12, Schedule B5.3, page 4, lines 3 and 20). Mr. Davis also discussed the Torus Containment Structure Coating Replacement project, Service System Transformer #65 and #69 Replacement project, Underground Safety-Related Service Water Piping project, Boraflex Fuel Storage Racks project, and the drywell cooler projects, and emphasized that none of the capital expenditures for the projects include contingencies (Davis, 7T 2545-2547, 2551-2553; Exhibit A-12, Schedule B5.3, page 4, lines 2, 4, 8, 9, 12, and 17).

Mr. Davis also explained the timing of Fermi 2's plant refueling outages (7T 2539-2540), and the components of Nuclear Fuel capital expenditures (Davis, 7T 2553-2555). He supported the expenditures as reasonable and prudent (Davis, 7T 2555-2556; Exhibit A-12, Schedule B5.3, page 1, line 10).

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).

Witness Coppola's proposal should be rejected because it would unjustifiably reduce the recovery of capital expenditures that DTE Electric has already reasonably and prudently incurred, and that the Company reasonably and imprudently 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).

The forecast of capital expenditures for Fermi 2 (depicted by Exhibit A-12, Schedule B5.3, page 1, line 11) accurately represents capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage. The projects and related capital

expenditures reflect DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045. These capital expenditures are reasonable and prudent given the regulations, goals and conditions under which Fermi 2 operates (Davis, 7T 2557). Therefore, the expenditures should be approved.

4. Distribution Operations (DO)

The Company's Distribution Operations (DO) organization focuses on the design, construction, maintenance and operation of the Company's electrical distribution system (Pfeuffer, 4T 234). DTE Electric's distribution system is aging, and, in many cases, equipment is operating beyond typical design life. A combination of this aging infrastructure, weather impacts, needed grid changes to support growth in distributed energy resources (DER) and load growth associated with electric vehicle (EV) penetration, and expanding regional economic activity requires a more robust, resilient, and modern grid infrastructure (Pfeuffer, 4T 237-238, 399). The capital investments (discussed here) and O&M expenses (discussed elsewhere) are necessary to achieve the Company's main goal of providing safe and reliable electricity to customers at reasonable rates. These investments also lay the foundation for grid modernization, which Customers require to support their evolving needs for greater resiliency in the face of increasingly frequent and intense storms, electrification including EVs, and integration of DER (Pfeuffer, 4T 230).

Capital expenditures totaled \$905 million in 2020 and 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)).²⁶

²⁶ 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).

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 (4T 370-377).

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 an accurate forecast for future emergent expenditures. Further, if the emergent expenditures do not materialize, 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 conditions and provides for appropriate planning (Pfeuffer, 4T 490-492).

ABATE witness York further suggested that normalization of historic emergent capital is “an effort to retroactively capture inflation cost increases” (8T 3037). It is not. 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. The Commission approved the Company’s normalization practice its most recent rate case. (See May 8, 2020 Order in Case No. U-20561, p 86.) AG witness Coppola noted his disagreement with the Commission rejecting his similar position on normalization in Case No. U-20561 (8T 4751), however he accepted the Company’s overall capital expenditures forecast for emergent replacements. Therefore, ABATE’s proposed methodology (rejecting normalization) should be rejected (Pfeuffer, 4T 492-493).

AG witness Coppola proposed a \$9.08 million reduction in emergent capital expenditures due to the success of the tree trimming surge in reducing power outages caused by trees (8T 4774). The Company disagrees because the proposal is duplicative. The Company included cost savings associated with reduced equipment failures from the tree trimming surge in Exhibit A-12, Schedule B5.4, page 1, line 6, as the Company explained in response to discovery (Pfeuffer, 4T 504; Exhibit A-41, Schedule FF15).

Staff requested that the Company “begin tracking equipment identified as imminent failure (near failure but has not failed) and exclude those costs from the emergent replacements capital program” (Becker 8T 5404). Staff did not specify where it thinks the costs should be assigned but seemed to imply by default that they should be assigned to strategic capital. The Company disagrees because these items are necessary reactive, unplanned work to prevent customer outages, prevent hazards and/or prevent any additional damage to the electrical system. When field personnel

discover these items, they initiate emergent replacements to the latest construction standard, but without the full planning and engineering that would go into strategic replacement. There is a similar need to immediately replace equipment whether it has failed, or failure is imminent. Staff's proposal to track a separate imminent-failure category is unnecessary and would require significant time and other resources to implement. Accordingly, Staff's request should not be adopted (Pfeuffer, 4T 494-970).

AG witness Coppola 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). The Company disagrees with his proposed approach because a five-year average of expenditures is not the most accurate representation of future expenditures in these categories. 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 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. 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 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 increase 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 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).

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:

1. *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).
2. *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).
3. *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).

Ms. Pfeuffer supported the actual and projected expenditures shown on Exhibit A-12, Schedule B5.4 as reasonable and prudent based on past expenditures, the projected requirements for labor and material needed for the safe and reliable distribution of electric power, and the investments that are needed to maintain and improve service to DTE Electric's customers (Pfeuffer, 4T 387-388). She also responded to various Intervenor suggestions (further discussed below), which should all be rejected because those suggestions would be detrimental to customers by reducing the Company's ability to (1) safely and reliably operate the electric distribution system, and (2) make the important strategic investments that are needed to make the grid more resilient and modernized, and ready for a future characterized by a greater level of DER and EVs (Pfeuffer, 4T 403).

i. 2020 Actual Expenditures versus U-20561 Forecast

The projected test year is a projection of the expenditures that the Company expects and intends to make given the information known at the time of the rate case filing. There is no guarantee of recovery, but it is well-established that the Company should recover the cost of prudently incurred capital expenditures for assets that it deploys to benefit customers. Under general ratemaking principles, the Company is entitled to the return "of" and "on" its investments in providing utility

service.²⁷ There is no basis to use hindsight to reconcile the difference between projected expenditures from a prior rate case against actual expenditures that are incurred, and the Company must have the flexibility to adjust to unexpected events, such as severe storms, and deploy capital and resources in a way that best serves customers.²⁸

Overall, the Company invested \$44.0 million more in 2020 than what was forecasted in Case No. U-20561 (approximately 5%).²⁹ The difference was primarily due to higher-than-projected Emergent Replacements (restoration of customer outages due to storm or equipment failure, 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

²⁷ 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).

²⁸ The Commission has no common-law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). The Commission is an “administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments.” *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). The Commission’s authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co*, 343 Mich 313, 326-27; 72 NW2d 292 (1955).

²⁹ 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).

increases restoration costs but results in a grid that is more robust to severe weather (Pfeuffer, 4T 242-243, 246, 249-252).

The Commission previously “direct[ed] DTE Electric, in its next electric rate case filing, to provide a detailed description of each type of expenditures assigned to the emergent replacements category” (May 8, 2020 Order in Case No. U-20561, pp 86-87). Accordingly, Ms. Pfeuffer explained that the Company tracks Emergent capital expenditures in three major categories: Storm,³⁰ Non-Storm (tracked in four subcategories: Emergent, Reactive, Corrective, and Environmental), and Substation Reactive (tracked in four subcategories: Major Equipment, Minor Equipment, Transformers & Regulators, and Non-Electrical Equipment) (Pfeuffer, 4T 253). Table 7 (at Pfeuffer, 4T 254-255) provides the details of each category. Table 8 (at Pfeuffer, 4T 255-256) shows 2020 Emergent capital expenditures by investment category. Expenditures in Storm and Non-Storm Emergent are incurred to support field activities under eight work types (Critical Infrastructure Customer, Emergency Job, Hazards, Multiple Customer Outage, Police/Fire, Public Safety Concern, Single Customer Outage, and Single Customer Problem) (Pfeuffer, 4T 256). Table 9 (Pfeuffer, at 4T 256-257) provides examples for each category.

In further response to MNSC’s inaccurate suggestion that the Company changed its emergent replacement policy to require replacements rather than perform lower-cost repairs (Ozar, 8T 3962-3963), 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

³⁰ A storm is declared when the number of outages exceeds 340 and the number of circuits impacted exceeds 125 (typically equivalent to 25,000 customers) (Pfeuffer, 4T 253).

of damage, and field conditions that affect the difficulty of a repair or replacement during storm or emergent conditions (Pfeuffer, 4T 250-251, 498).

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.]

ii. The Company's Projected DO Capital Expenditures

The Company's projected DO capital expenditures in Case Nos. U-20162 and U-20561 were based on an evolution of the Five-Year Plan that was submitted in Case No. U-20147. The August 20, 2020 Order in Case No. U-20147 re-affirmed the Commission's over-arching objectives (safety, reliability and resiliency, cost effectiveness and affordability, and accessibility) and issued updated distribution plan requirements and guidance. Accordingly, on September 30, 2021, DTE Electric filed a final 2021 Distribution Grid Plan (DGP; Exhibit A-23, Schedule M1) that provides both a detailed five-year investment plan, and a longer-term 10- to 15-year vision for the grid

(Pfeuffer, 4T 263-264). Ms. Pfeuffer further explained the Company's grid modernization strategy, and corresponding investments (4T 265-278).

Ms. Pfeuffer further explained that strategic investment programs are evaluated against seven impact dimensions in the Company's Global Prioritization Model (GPM), which is a benefit-cost analysis (BCA) that the Company developed to assess the impact that strategic investment programs and projects are expected to have on the grid in order to meet customer needs (Pfeuffer, 4T 277-278; Exhibit A-23, Schedule M7). Table 11 at 4T 279-80 shows the top 50 Strategic Capital investments, excluding "must do" projects and some other projects that are already well underway (Pfeuffer, 4T 279-281).³¹

The three key objectives that the Company is pursuing on behalf of its customers are: (1) safety; (2) improving reliability; and (3) avoiding emergent costs. Improving safety is the Company's highest priority, and planned investments will address this priority directly. In particular, tree trimming and the 4.8kV Hardening program will continue to reduce the risk associated with downed power lines. And investments in the Substation risk program, System cable, and Breakers will continue to reduce the risk of equipment and substation failures that could leave a large number of customers without power for an extended period of time. Reliability is measured by several metrics, including the all-weather System Average Interruption Duration Index (SAIDI) and by SAIDI-Excluding-Major Event Days (MEDs). DTE Electric fell in the fourth (worst) quartile for all weather SAIDI in several of the past years, but the Company's SAIDI Ex-MED was in the 3rd quartile in 2020 and was trending towards the 3rd quartile for 2021. (Pfeuffer, 4T 240, Figure 2). The Company's April 1, 2022 Power Quality Report, filed in MPSC Case No. U-16065,

³¹ Tree trimming is the highest priority strategic program, but it is not in the table because the costs are O&M, and not capital (Pfeuffer, 4T 279). See section on Distribution Operations O&M Expenses for a further discussion regarding tree trimming.

p 3, shows that DTE Electric achieved a 2021 SAIDI Ex Meds of 136 (as compared to SAIDI Ex-Med of 142 for 2020). Apart from the extreme weather in the summer of 2021,³² SAIDI Ex-Med demonstrates that the day-to-day reliability of the Company's system has increased based on recent investments and is on track to achieve second quartile performance by 2025. Improving reliability is a key focus for strategic investments and is critical to achieving the Company's goal to operate at the industry average or better for SAIDI (Pfeuffer, 4T 241, 281-284).

Strategic Capital investments will also help the Company manage costs because, if they are funded and implemented as proposed, then the Company forecasts that capital required for emergent replacements will be reduced compared to what it would have been otherwise (Pfeuffer, 4T 286; Exhibit A-12, Schedule B5.4, page 1, line 6; the reductions in emergent O&M is reflected in Exhibit A-13, Schedule C5.6, page 1, line 19). The present value of the economic benefit to customers from the Strategic capital and tree-trimming investments is estimated to be \$9.8 billion to \$13.2 billion (Pfeuffer, 4T 286-287; Exhibit A-23, Schedule M8).

In general response to proposed disallowances, the Company first notes that 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 Company disagrees because 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). Thus, even assuming for arguments' sake that this type of analysis is to

³² All-weather SAIDI for 2021 through October 31 was worse than 2020 because of the significant frequency and intensity of storms experienced in the summer of 2021 (Pfeuffer, 4T 239, 257-262).

be done at all (which it should not be), the analysis should be done on a dollar-weighted basis (Pfeuffer, 4T 407-409; Exhibit A-41, Schedule FF1).

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 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).

The Company has also adjusted its emergent forecast to better align with its experience in the last three years, changed its planning process, and secured resources that will address any potential supply chain challenges (Pfeuffer, 4T 411-412).

More specifically, AG witness Mr. Coppola proposed disallowances of \$208,907,000 for the ten months ending October 31, 2022, and \$251,997,000 for the projected test year, based on his calculation of a 20% average annual growth rate on strategic capital programs of approximately 20% from 2017 to 2021 (8T 4760-4761). The Company disagrees 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 2016 (Exhibit A-41, Schedule FF18). 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% when including 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 only look at strategic capital, 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 ignored 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 false 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 doubling³³ 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).

For all of these reasons and as further detailed in Ms. Pfeuffer's rebuttal testimony, the AG's proposed disallowances should be rejected (Pfeuffer, 4T 406-421).

ABATE witness York proposed, against Commission precedent, that the Commission limit additions to rate base attributable to Strategic Capital programs to those that will be in service by the end of the projected test year (8T 3038). The Company disagrees because project costs can be included in rate base if they are deemed reasonable and prudent regardless of whether they will be in service in the projected test year.³⁴ The capital expended on these multi-year projects receive a

³³ The proposed increase in total capital for distribution operations is 17%, and the increase in strategic capital only is 39%, (Pfeuffer, 4T 416-419).

³⁴ The Court of Appeals previously rejected the contention that the Commission has no authority to apply anything other than the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). The Commission is not bound to apply any particular formula or use any specific method in setting rates. *Id*; *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524; 342 NW2d 273 (1983); *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6; 607 NW2d 391 (1999).

different accounting treatment (construction work in progress, or CWIP) under Commission orders going back to 1976.

Company witness Uzenski explained that CWIP is forecasted, in part, based on the expected in-service date for large projects, when they are reclassified from CWIP to Plant in Service. Generally, these projects include Allowance for Funds Used During Construction (AFUDC), which is credited on the income statement, reducing the revenue deficiency, and offsetting the impact of the assets in rate base. AFUDC is applied to projects greater than \$50,000 and lasting more than six months, with some exceptions for environmental and other specifically ordered projects. For example, in Case No. U-5281, the Commission required that pollution control related to CWIP should not accrue AFUDC but instead be included in rate base (March 14, 1980 Order in Case No. U-5281, pp. 114-117, 127).

However, CWIP can also include lower cost, short duration projects that are not eligible for AFUDC. Specifically, the Company initially charges projects involving small dollar assets, or mass assets, to CWIP but then soon transfers them to Plant in Service. Lastly, the Company includes capital expenditures for the Blue Water Energy Center in rate base without an AFUDC offset as ordered by the Commission in Case No. U-18419. (Uzenski, 7T 2743-2744).

Accordingly, ABATE's proposal should be rejected as contrary to decades of Michigan utility ratemaking and accounting treatment. Also, project completion dates are often based on the final steps of a project, and customers receive the benefits of the work done before these final steps (*e.g.*, improved reliability where the final step is to decommission an old substation) (Pfeuffer, 4T 415-416; Uzenski, 7T 2391, 2743). ABATE's proposal should also be rejected because it is based on the inaccurate proposition that "DTE has not provided detailed information supporting the amounts of capital expenditures expected to be incurred during the bridge period and projected test

year” (York, 8T 3038). To the contrary, the Company’s DO witnesses provided over 500 pages of testimony, over 1,281 pages of exhibits, and responded to nearly 2,000 audit and discovery questions in this case providing details regarding each of these programs including in-service dates (Crozier, 7T 2392). The exact in-service date is not relevant to whether an investment is reasonable and prudent and is only relevant in terms of how the Company accounts for expenditures (e.g., CWIP and AFUDC). ABATE witness York did not argue that the projects were not reasonable and prudent investments, or that they would not be used and useful upon completion. Witness York also misunderstands that many of these multi-year projects include components that will be used and useful during the test year. Company witness Pfeuffer explained that, for instance, “when the Company performs conversion work, the circuits are converted over multiple years and the final step is to decommission the old substation.” (Pfeuffer, 4T 416) The CODI: Garfield Network Upgrade is a perfect example; while the old substation will not be decommissioned until after 2025, cutover of circuits will take place over the next several years. Pfeuffer explained that “Customers will benefit from reduced trouble events, wire downs, and improved reliability from the construction and cutover work on the circuits, long before the Garfield substation is decommissioned, and the project is finally closed out.” (Pfeuffer, 4T 415-416). ABATE witness York’s proposed disallowance should be rejected.

iii. Specific Strategic Capital Investment Programs

As discussed above, DTE Electric’s planned Strategic Capital investments are focused in three areas: 1) Infrastructure Resilience & Hardening, 2) Infrastructure Redesign and Modernization, and 3) Technology and Automation.

a. 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). The Company plans to invest in 28 different programs in this category. Four warrant particular discussion: (1) 4.8 kV Hardening, (2) Pole and Pole Top Hardware (Pole Top Maintenance and Modernization, or PTMM), (3) Cable Replacement, and (4) Underground Residential Distribution (URD) Replacement, as discussed below.

As a preliminary matter, however, Staff proposed a 15% disallowance (\$39.854 million in the bridge period; \$51.914 million in the test year) based on underspending in 2020 and 2021 compared to the forecast from Case No. U-20561 (Becker, 8T 5410-5411). The Company disagrees 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 421-422)).³⁵

1. 4.8 kV Hardening.

This program, a sub-program of Infrastructure Resilience and Hardening, was developed as a cost-effective way of providing improvements in safety and reliability at a faster pace than simply converting the entire 4.8 kV system in the city of Detroit, which is estimated to cost over \$4 billion

³⁵ 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 greater than Staff suggests (Pfeuffer, 4T 422; Exhibit A-41, Schedule FF4).

and take more than a decade to complete. Primary components of the program include replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, 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 equipment, removing service lines to abandoned properties, and trimming trees to support construction activities (Pfeuffer, 4T 291, 423-424). 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 program has proven very effective in improving the safety and reliability of one of the oldest parts of the Company's electrical grid (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).³⁶

MNSC witness Ozar suggested that the Commission maintain the same level of annual spending as in 2021 (8T 3984). The Company disagrees. The discussion above largely addresses some of Mr. Ozar's indicated misperceptions. He also suggested 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). The Company disagrees because tree trimming alone will not remove the DPLD-owned arc wire. Mr. Ozar also incorrectly assumed 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. The Company also expects to include the program in its more formal Environmental Justice plan.³⁷ Therefore, MNSC's

³⁶ 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).

³⁷ 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 EVs and DERs, and that hardening does not delay the conversion to 13.2kV (Pfeuffer, 4T 508-509, 119).

proposal to cap the 4.8kV Hardening program at the 2021 investment level should be rejected (Pfeuffer, 4T 423-428).

2. *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 inspected have reduced strength and need remediation (Pfeuffer, 4T 302). The Company is increasing its investments in this area due to enhancements made to the program specifications based on benchmarking and learnings from other key programs. 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 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 because (1) the 4.8kV hardening program is scheduled to end in 2026, reducing the number of poles that the Company inspects; (2) inspections under the Pole/PTMM program are done to an updated, more robust standard; (3) benchmarking showed that a 10-year

inspection cycle (or less) was industry best practice; and (4) the Pole/PTMM program is the best available option to 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 being inspected for below-grade decay. This results in the identification of more poles requiring 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. Only about 12% of the Company's current poles are higher-class poles, so the higher-class pole will be required for close to 90% of pole replacements. Customers will receive safety and reliability benefits from stronger poles that are more resilient to storms and wind (Pfeuffer, 4T 251, 432).

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

3. Cable Replacement.

This program prioritizes and replaces system cable based on multiple factors including cable type, vintage, failure history, system impacts, and cable loading. There are approximately 3,100 miles of underground system cable on the Company's distribution and subtransmission systems. The Company is ramping up its cable replacement efforts, which will benefit customers through reduced risk of lengthy outages, improved reliability, and lower reactive costs (Pfeuffer, 4T 305-310).

4. Underground Residential Distribution (URD) Replacement.

This program prioritizes and replaces URD cable based on multiple factors including vintage, number of failures, and number of customers affected by those failures. There are approximately 11,000 miles of URD cable on the system, with approximately 2,800 miles (25%)

being pre-1985 (non-tree-retardant).³⁸ The Company has successfully ramped up its underground replacement program in recent years and is confident that it will be able to execute the URD Replacement program presented in this case (21 miles in 2021; 28 miles in 2022; and 45 miles in 2023). Customers will benefit from improved reliability because the program will reduce the number and length of customer interruptions due to URD cable failures. Fewer URD cable failures will also result in a reduction in reactive costs (Pfeuffer, 4T 310-313).

Staff (Becker 8T 5412-5413) and MNSC witness Ozar (*e.g.*, 8T 3968, 3999-4016) questioned whether certain items relating to the 4.8kV Hardening and PTMM programs should be recorded to expense instead of capital. Company witness Uzenski explained that the Company's capitalization policies are appropriate under the USOA and otherwise reasonable and based on actual work performed. The Company also agrees to file reports supporting the capitalization policies relating to inspection costs questioned by Staff and MNSC (Uzenski, 7T 2775, 2790-2792).

b. 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). Significant programs include Subtransmission Redesign & Rebuild, City of Detroit Infrastructure (CODI), 4.8kV Conversion, Strategic Undergrounding Pilots, System Loading, and 8.3kV Pontiac Conversion, as discussed below.

³⁸ "Treeing" refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure (Pfeuffer, 4T 310).

As a preliminary matter, 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). 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).³⁹

1. 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 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).

³⁹ 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).

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 Company disagrees because it has identified and supported actual projects 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).

2. *CODI.*

This program is needed to address the significant portions of the electrical infrastructure in the downtown area of the City of Detroit including hospitals, stadiums, and universities, which were placed in service in the early part of the 20th century. Development in the City of Detroit is stressing this aging infrastructure, and the Company cannot serve new customer load with existing capacity. The Company is focusing on ten CODI projects between 2021 and 2023, as shown on Table 15 of Ms. Pfeuffer's direct testimony (Pfeuffer, 4T 324-327. See Exhibit A-23, Schedule M5 for more detail).

3. *4.8 kV Conversion.*

This program is aimed at upgrading the aged 4.8 kV system to higher grid voltage by building new substations and upgrading circuits to add capacity to serve growing load, and to address deteriorating reliability performance due to aging electrical infrastructure. This will be a significant investment that the Company expects to occur over several decades (Pfeuffer, 4T 328-332). The investments presented in this case reflect investments that address current loading constraints on the system (Pfeuffer, 4T 331; See Exhibit A-23, Schedule M5 for details). Ms. Pfeuffer provided additional details on two representative projects for a deeper understanding of the drivers, scope, and benefits of 4.8kV conversion: (2) Buckler Circuit Conversion (4T 332-333), and (2) Lapeer – Elba Expansion and Circuit Conversion (Apollo) (4T 333-334). The Company

also operates some circuits at 4.8kV that are fed from a 13.2 kV substation, which are known as isolation down areas (ISO down). The portion of the program for converting ISO down areas is aimed at upgrading portions of the circuits to a higher voltage, thus adding capacity to serve existing load, and to address deteriorating reliability performance due to aging electrical infrastructure. The ISO Down portion of the project may span multiple decades due to the extensive scope of work, but in this case the Company is targeting two ISO Down locations for conversion: Camden substation, and Gilbert Substation (Pfeuffer, 4T 334-336; See Exhibit A-23, Schedule M5, pp 264-271 for details).

4. 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 to determine whether undergrounding might provide a solution to alleviate weather-related outages. 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 to improve reliability as compared to overhead 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 surface conditions than 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).

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 (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).

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 considerations beyond cost (Pfeuffer, 4T 343, 440-443).

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 services⁴⁰ differs from the 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 benchmarking and 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 impact that undergrounding services has on storm restoration times. Also, if the results of the services pilot show that it is cost effective and results in enhanced reliability for customers, then the pilot might be expanded, or undergrounding residential overhead services might be suitable for widespread adoption (Pfeuffer, 4T 342, 445-447, 349; Exhibit A-23, Schedule M1, pp 346, 349, 356).

⁴⁰ “Services” refers to individual service drops that connect a single customer location to a nearby distribution line.

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 Company agrees that lifecycle cost analysis is important, but it is important to keep in mind 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).

In summary, Commission has expressed its interest in improving reliability in Detroit and other parts of the Company's service territory. Strategic Undergrounding is an important part of the Company's plan to achieve that goal. The Company expects to reduce the cost by increasing the volume of work and utilizing the lessons learned from the Appoline pilot and benchmarking. Therefore, the Commission should fully approve the requested funding (Pfeuffer, 4T 450).

5. System Loading.

These projects add capacity to the distribution system, and typically include construction of new substations, expansion of current substations by installing additional transformers or replacing existing transformers, installing new switchgear lineups, creating new distribution circuits, reconductoring circuits, converting circuits to 13.2kV, and transferring load once additional capacity has been created. Many areas identified in the priority ranking for system load relief are addressed as part of CODI, 4.8kV Conversion, or 8.3kV Pontiac Conversion programs. Load relief needs that are not included in those programs are part of the System Loading projects category (Pfeuffer, 4T 344-345).

6. 8.3kV Pontiac Conversion.

This program concerns the 8.3kV system that serves the city of Pontiac. The Company acquired the system from CMS Energy in the 1980's, and it is the only 8.3kV in the Company's

distribution system. As an island surrounded by the 13.2kV system, there is a high risk for stranded load in the event of a substation outage. Plus, the 8.3kV system is aged, replacement parts are often unavailable due to obsolescence, and Pontiac has increased its load in recent years. Therefore, the Company has developed a plan to upgrade and convert the Pontiac system to 13.2KV as part of grid modernization, starting with upgrading the system vaults as outlined in previous rate cases and section 8.19 of the DGP (Pfeuffer, 4T 346-347).

c. 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), as discussed below. This brief first addresses generic proposed disallowances before moving on to the specific investments.

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 misleading 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 elsewhere. 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-spent its forecast, lacks logical support.

In summary, Staff's analysis has numerous flaws and 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.⁴¹ The Company's analysis, applying Staff's 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).

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 USOA's 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

⁴¹ ESOC and ASOC are rightly excluded because, as major building construction projects, they are different in kind from all other technology and automation investments.

of project and the direct costs charged to the project, Staff's proposed fixed rate has no sound basis and is unreasonable. 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 proposed disallowances (\$9,726,000 in the bridge period; \$16,060,000 in the projected test year) for capital costs of all Technology and Automaton 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. 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 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).

1. Grid Edge Insights & New Technology

Staff proposed a complete disallowance (\$1.989 million in the bridge period; \$1.783 million in the projected test year) for the Grid Edge Insights & New Technology project, reasoning that there were conflicting scopes provided in Company exhibits and a discovery response (Wang, 8T 5185-5186). Staff’s proposal lacks a sound foundation because it relies on Exhibit S-7.12, page 3, which was a discovery response referencing the scope for New Technology Pilots. The Company noted that if there are any new technology pilots (*future* potential expenditures), then the costs would be shown on this line item but did not imply that this changed the *current* scope of work proposed in the Grid Edge Insights & New Technology project. The Company also confirmed the current scope of work for this project by identifying some of the specific scope of work, but Staff ignored this confirmation. Thus, the Company did not provide conflicting scopes for the project, and the Company also provided evidence of the current scope of the project with specific detail, so Staff’s proposed disallowance should be rejected (Pfeuffer, 4T 467-468).

2. 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)

3. Distribution Automation.

DTE Electric's efforts on Distribution Automation⁴² have unfolded over the past several years. Today, roughly 32% of general-purpose substations and 25% of the distribution circuits in DTE Electric's territory have SCADA monitoring and control. Approximately 5% of the distribution circuits have automatic loop schemes, which can automatically transfer sections of the circuits onto adjacent circuits when an outage is detected. The Company is strategically implementing Distribution Automation to maximize customer benefits. The scope of work for 2021 includes the design of full SCADA control and monitoring of one substation and development of standards and processes that can be utilized to accelerate the installation of distribution automation equipment across the electrical system, as well as the design of 5 substations and 25 circuits for automation in 2022 (Pfeuffer, 4T 351-355).

4. 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)

⁴² The Department of Energy (DOE) report "Distribution Automation: Results from the Smart Grid Investment Program," published in September of 2016, states: "Distribution automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring; and outage, voltage and reactive power management. Automation can improve the speed, cost, accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers" (Pfeuffer, 4T 351).

that the Commission approved in Case No. U-20471.⁴³ 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 Commission authorized in the IRP (see MPSC Case No. U-20471, Order dated February 20, 2020, 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,⁴⁴ 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 also did not indicate any

⁴³ 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).

⁴⁴ 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).

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, Staff's proposed disallowance should be rejected (Pfeuffer, 4T 487-489).

5. Automation Configuration and Test Record Database.

Staff 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.

6. 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).

7. 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 prudence 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).

Staff proposed numerous disallowances for NWA expenditures, referring numerous times in discovery responses to a need for “ample evidence” (Exhibit A-41, Schedule FF13). 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).

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).

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).

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, 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).

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, which is still an option should any problem arise with the existing battery. 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).

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). Therefore, Staff's 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). This disallowance is inappropriate because since the time of the filing

of the instant case, the Company has internally approved the project, and it is proceeding (Pfeuffer, 4T 476; Exhibit A-51, p 2).⁴⁵

Staff proposed a full disallowance (\$678,000 in the bridge period; \$292,000 in the projected test year) for the NWA: Small Solar and Storage Testbeds project (Wang, 8T 5183), reasoning that: “Only studying these technologies in customer installations will yield information on the real-life behavior, issues, and opportunities from actual installations within the Company’s service territory... The necessity of conducting a pilot in a testbed and laboratory setting, instead of initiating field deployment, is not clear and the benefits of it over field deployment are not justified by the Company” (Wang, 8T 5178-5179).

Staff’s reasoning is incorrect for several reasons including: (1) Some of the interactions and tests will recreate scenarios that would not be safe at a customer location but can be tested in a controlled and safe environment in the lab; (2) In the lab, tests could be undertaken without having to gain access to customer locations and/or modifying customers’ premises and without impacting customers’ power quality; (3) In the lab, the Company can reuse the infrastructure for different testing scenarios, instead of having to find or create scenarios in the field; (4) The lab gives the Company the ability to collect high data resolution and detailed information, and to reuse monitoring hardware; (5) In the lab, the Company can repeatedly test scenarios (*e.g.*, abnormal electrical system events that might occur infrequently in the field) and generate new scenarios; and

⁴⁵ In further response to Ann Arbor witness Stults’ suggestion that the Veridian project would not lead to a true microgrid, Ms. Pfeuffer further explained that the project as proposed by the Company meets the conceptual definition of a microgrid (4T 485). Ms. Pfeuffer also provided a further discussion regarding Ann arbor grid planning, addressing among other things witness Stults’ apparent misperceptions (4T 523-281).

(6) testing will include capabilities that are emerging or not currently available on the market, so the Company will be better prepared when the capabilities are mature (Pfeuffer, 4T 776-778).⁴⁶

Staff further suggested that testing is not necessary prior to field deployment because of “the findings and outcomes from research organizations like EPRI, the learnings from other U.S. utilities, and the Company’s prior experimentation with smart inverters” (Wang, 8T 5179). The Company generally agrees that there is value in participating with organizations such as EPRI and benchmarking with other utilities and does not intend to duplicate efforts; however, technology is evolving rapidly, and the Company seeks information regarding how it could be utilized on the Company’s system. Using EPRI or similar organizations as a substitute for the testbed would require building testing that is specific to DTE Electric’s system and use cases. The Company would be charged for this service, and be subject to EPRI’s or others’ schedules, which might not align with when the Company needs the information (Pfeuffer, 4T 478, 481). Staff also acknowledged in discovery that the Company is in a better position to determine the availability of test reports on situations that are unique to the Company’s distribution system (Pfeuffer, 4T 480-481; Exhibit A-41, Schedule FF14).

Staff further suggested that “the Company has previously conducted field experiments of smart inverters directly without the creation of a testbed” (Wang, 8T 5180). Staff oversimplified the Small Solar and Storage Testbeds project. The Company has demonstrated technology in the past without creating a testbed only where it first conducted a risk assessment, and the installed physical and engineered controls allowed minimal to no potential adverse effects (Pfeuffer, 4T 779).

⁴⁶ Staff also seemed to have the impression that the Company would develop NWAs in an office environment. The Small Solar and Storage Testbed provides technical facilities to develop NWAs, akin to a lab environment (Pfeuffer, 4T 483).

Staff also neglected that, unlike utility grade smart inverters, retail consumer electronics are frequently designed with fewer or no safety features to meet lower price points. The Company discovered (while designing the test bed) that these lower-priced inverters can pose safety and reliability risks due to the lack of security features. If the Company does not have the Small Solar and Storage testbed, then this type of grid-impacting flaw might go undiscovered and could potentially lead to safety or reliability concerns that the Company would have to resolve in the field. This situation can be avoided if issues are identified in the testbed and resolved prior to installation (Pfeuffer, 4T 480-483).

The Company invested significant resources, in both time and capital, to develop a robust suite of NWAs in response to the Commission's request. 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.]

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. Staff's proposed disallowances are unfounded, and at times contrary to Staff's own evidence. Therefore, Staff's proposed NWA disallowances should be rejected (Pfeuffer, 4T 484).

GLREA witness Richter proposed a complete disallowance of the NWA-type pilots (8T 3248-3252) apparently based on some concern about Company ownership, but he failed to make a

reasoned argument that the information gathered by the pilots will not benefit the Company or its customers, nor does he claim that the investment is unreasonable or imprudent. The Company proposes to study, for example, the impact of charging stations on the grid, including cyber security (Exhibit A-12, Schedule B5.4.10 pages 1-4; Exhibit A-23, Schedule M1, pages 415-416). The pilots proposed by the Company have a direct relation to power quality and reliability and should be tested by the Company with Company ownership to allow for the access required to fully study the technology. Therefore, GLREA's proposed disallowance should be rejected (Pfeuffer, 4T 486).

8. 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 the flow of 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); Distribution Management System (DMS).⁴⁷ 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).

⁴⁷ The Company is also adding the Network Management System (NMS) as part of ADMS.

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).

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).

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).

AG witness Coppola proposed 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), asserting:

[T]he cost overruns have not been adequately justified and at least a major portion of those incremental cost may have been imprudently incurred. It would neither be fair nor reasonable for the Company to recover 100% of those from customers. The Company needs to be held accountable for its premature decision to proceed with a suite of products that were not fully developed and proven [Coppola, 8T 4769].

The Company disagrees because 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).

AG witness Coppola 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).

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 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. 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).

iv. 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 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).

Both facilities are justified and should be fully funded. 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) 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:

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.]

AG witness Coppola proposed a \$20.5 million 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).⁴⁸

The Company disagrees. 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 to keep these personnel close to the control room as a best practice (Elliott Andahazy, 7T 1545-1546).

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

⁴⁸ The AG’s suggestions that the Company must satisfy a “compelling and convincing” burden of proof or some nebulous “adequately justified” standard are contrary to applicable law including the “preponderance of the evidence” standard, as discussed in section IV.

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. Therefore, the AG's proposed disallowance should be rejected as unfounded and unreasonable (Elliott Andahazy, 7T 1546-1547).

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).

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 serves, 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.⁴⁹ 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 ignored 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,

⁴⁹ *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).

explaining why the current hybrid work structure does not negate the need for the additional space (Elliott Andahazy, 7T 1546-1547, 1548-1550).

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).

Staff also did not suggest that the Company doesn’t need the ASOC or that the investment is not reasonable or prudent. The Company also addressed the need for the ASOC in Case Nos. U-20162 and U-20561 and provided additional testimony in this case addressing the need for the ASOC, the new plans, and the costs. There also is no reason to think that construction of the ASOC will not occur (as Staff suggests) because the Company is obligated to meet NERC and business continuity requirements to have an alternate control center in case of a locational emergency at ESOC. Groundbreaking is planned by early 2023. The reason that construction did not occur previously was due to discovery of inflated costs associated with the original project, and the Company made changes to the project, including relocation to a dual-purpose site, that will keep the investment in line with the original estimates (Elliott Andahazy, 7T 1527-1530, 1551-1552).

For all of these reasons, the AG and Staff’s proposed disallowances should be rejected as unfounded and unreasonable, and the Company’s SOC: ESOC and ASOC requests should be fully approved.

v. Contribution in Aid of Construction (CIAC)

In DTE Electric’s last general rate case, MEC Coalition witness Jester proposed “CIAC reform” that would “establish that DTE Electric’s maximum contribution to distribution system extensions and connections will be 4.5 times the estimated annual distribution revenue from the customer” (U-20561, 9T 3820). The Commission did not adopt that proposal, but sought additional information, stating:

The Commission finds that the MEC Coalition’s specific proposal to limit DTE Electric’s contribution to 4.5 times the estimated annual distribution revenue from the customer was not sufficiently supported. However, the Commission finds that it would benefit from additional information on whether the current CIAC policy fully reflects cost-of-service principles. As such, in the company’s next rate case, the Commission directs DTE Electric to: (1) provide supplementary, substantial, and specific support of the current CIAC model, (2) demonstrate that the current CIAC model is cost-of-service based, (3) provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs, and (4) provide details regarding how new customer connections drive upgrades to the system that may benefit other customers. [May 8, 2020 Order in Case No. U-20561, p 98.]

Company witness Willis responded by first explaining DTE Electric’s current CIAC policy for various customers. For Commercial and Industrial (C&I) customers, the standard allowance is two times the estimated annual revenue less surcharges and fuel cost anticipated to be collected from the customer. C&I customers with new or expanded loads of 1,000 kW and larger can alternatively select a standard allowance from the standard allowance table provided in Section C6.2(4)(a) of the Company’s rate book. The standard allowance table was approved in 2012

(October 31, 2012 Order in Case No. U-17055) and is updated as new rates are approved (Willis, 6T 950-951).⁵⁰

Turning to the first issue, the current model (both the two times annual margin approach and standard allowance table) uses a principled and fair approach to determining CIAC allowances. The current model should continue to be used because it: (1) appropriately calculates allowances based on a customer's total margin contribution and approved components of cost of service; (2) provides transparency regarding the amount of allowance through the standard allowance table to eligible customers considering locating or expanding in DTE's service territory; (3) maintains consistency with the Company's CIAC Standard Allowance Table; (4) maintains the value proposition previous customers have received, and avoids the inequity of increasing up-front costs to new customers without any offsetting credit in the base rate they pay going forward; and (5) maintains the Company's ability to attract new customers to locate in its service territory who will contribute to fixed costs shared by other customers and may also provide system upgrades benefits to other customers as a result of their line extension (Willis, 6T 951-952).

Customer benefits are further reflected in the Commission's press release accompanying its Order in Case No. U-17055 (approving the standard allowance table), which states:

The MPSC today approved an important change that will make Michigan more attractive to businesses considering new or expanded operations . . . From now on these businesses may choose to use a standardized approach by Michigan's two largest electric utilities to calculate their construction costs upfront for new electric facilities. This will help make siting comparisons easier for these businesses and improve Michigan's economic development climate. [Willis, 6T 953-954.]

⁵⁰ Mr. Willis proposed updates to the CIAC standard allowance table for customers with new or expanded load greater than 1000 kW consistent with the method approved in Case No. U-20561. The table can be found in Exhibit A-16, Schedule F8, Section C6.2 (Willis, 6T 948-949).

In contrast, the MEC Coalition's proposal from Case No. U-20561 to use only distribution margin to determine CIAC allowances is fundamentally flawed because it would (1) disproportionately and negatively impact higher voltage new business customers that bring added economic activity to the region; (2) decrease the available allowance for nearly all customers; and (3) fail to appropriately credit customers for their total share of fixed cost recovery (Willis, 6T 952-953). The MEC Coalition's proposal would dramatically increase upfront costs to large customers, and it is reasonable to conclude that such cost increases could alter customers' plans to locate or expand in DTE Electric's service territory (Willis, 6T 957-958).

With regard to the second issue, Mr. Willis further explained that the CIAC model used to determine the allowances in the standard allowance table follows cost-of-service principles, calculates margin contributions based on currently-approved rates, and utilizes the financial inputs approved by the Commission for use in the Company's cost of service (COS) models to determine the revenue requirement of the capital investment of customer connections over a 30-year period (Willis, 6T 959. See also 6T 954-955, further explaining the model's mechanics, including how the financial and rate inputs are cost based).

The two-times-annual margin method also continues to be based on Commission-approved cost-of-service and margins. The method produces results similar to the standard allowance table, which is anchored in cost-of-service principles as summarized above (Willis, 6T 959).

With regard to the Commission's third issue, Mr. Willis explained that customer connection allowances are based on margin (total base revenues, minus fuel costs, leaving revenues that a customer contributes to fixed costs). A standard allowance provided to a customer would be fully recovered over the specified contract term (1 – 5 years) and all margin beyond the contract period would contribute to fixed costs. This effectively lowers the fixed cost requirement for all other

customers. The new customer also contributes to surcharges, such as the nuclear surcharge and energy waste reduction (EWR), thereby reducing those costs to other customers. New customers also contribute to O&M expenses just like existing customers. Therefore, other customers are made whole for the line extension investment, and the new customer load will also likely continue to contribute to utility fixed costs after the term associated with the allowance (Willis, 6T 960).

Company witness Robinson addressed the fourth issue by explaining that, for example, a customer connection can result in increased distribution circuit capacity through reconductoring with larger wires, adding transformer capacity, or through the creation of a new circuit, which unloads existing circuits in the area. He also provided an example, which he quoted from Company records of an actual customer connection, where the customer's requested load exceeded available capacity on the circuit, so the only way to provide service was to establish a new circuit that created incremental capacity (beyond the capacity needed to serve the requesting customer) that benefitted customers affected by the upgrades. Plus, the requesting customer was relocating from other sites, which freed up existing circuit capacity at those locations, and thereby deferred or eliminated the Company's need to upgrade those circuits in the future due to normal load growth, as well as the corresponding need to recover upgrade costs from customers (Robinson, 7T 1573-1574).

This evidence fully complies with the Commission's directive for the Company to provide additional information and demonstrates that the current CIAC policy remains appropriate and should continue to be used (Willis, 6T 960-961).

MNSC witness Ozar proposed that the revenue requirements associated with the Company's credits toward CIAC should be split in two, with one group continuing to be assigned to distribution revenue requirements and recovered in distribution charges, and the second group assigned to power supply revenue requirements and recovered in power supply charges (Ozar, 8T 4036-4037).

The Company disagrees because credits for line extensions support investment in distribution plant for equipment such as transformers, conductors, poles, etc. System work for line extensions is not an investment in production plant, so credits should not be recovered in the production (power supply) revenue requirement. The current approach, in which distribution plant investment is recovered through distribution rates, continues to be the most appropriate method for recovering CIAC credits (Willis, 6T 996).

vi. 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. AMI meters are automatically read, monitored and controlled, instead of relying on manual actions (such as meter readers).⁵¹ As of December 31, 2019, the Company's AMI program is considered fully implemented. Analog meters remain only at sites where the Company has no access, and the Company continues to support the ability of customers to opt-out as long as they pay the extra costs of manual reading so that other customers do not have to subsidize those costs (Smith, 7T 1892).⁵²

⁵¹ The Commission reviewed DTE Electric's AMI program and approved incremental funding for the Company's AMI investments in successive general rate cases, beginning with the December 23, 2008 Order in Case U-15244, p 62, which was not appealed. More recently, the Commission has declined to revisit the AMI issues and arguments that it thoroughly reviewed and addressed in past cases, and the Court of Appeals has affirmed. December 11, 2015 Order in Case No. U-17767, p 34, aff'd *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 13, 2018 (Docket Nos. 331599, 331868, and 332159); January 31, 2017 Order in Case No. U-18014, p 129, aff'd *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued October 25, 2018 (Docket No. 338378).

⁵² See Case No. U-20837. The Commission originally approved the cost-based rates for DTE Electric's opt-out program in Case No. U-17053. The Court of Appeals affirmed, and the Supreme Court declined to grant leave or to reconsider that denial. *Application of Detroit Edison to Implement Opt-Out Program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), *lv den* 499 Mich 868 (2016), *recon den* 499 Mich 972 (2016).

Company witness Mr. Smith discussed AMI's benefits to utility customers (7T 1892-1903), and supported capital investments for AMI technology enhancements including the AMI 3G to 4G⁵³ communication upgrade (7T 1904-1912).

Benefits from sustained usage of AMI technologies include: (1) Meter reading (Automation of meter reading provides daily and on-demand, accurate meter reads for each customer meter. DTE Electric has nearly 2.6 million electric meters. AMI eliminates the need to gain access for inside meter reads, and thereby significantly reduces meter-reading costs and customer inconveniences. For example, there has been a tremendous reduction in customers receiving estimated bills for two or more months; (2) Turn on / Turn off (Remote capability to connect or disconnect electrical services enables more responsiveness to customer requests for Account Services as well as eliminating costs and reducing safety risks arising from field visits); (3) Bill accuracy (customers benefit from the elimination of estimated bills, and are billed for actual usage, eliminating the need for estimated bills and related adjustments); (4) Theft and tampering notice (For example, tamper alarms enable the Company to reduce the timeframe to identify possible theft from months to days); (5) Safety (customers and employees benefit from increased safety through the decreased risk of injuries from slips and falls, dog bites, vehicle accidents, and COVID-19); and (6) Electric Reliability (Outage Detection; Restoration Efficiency; Power Quality; Daily storm and non-storm statistics; Tree trim program enhancement; and Enhanced automated job closures) (Smith, 7T 1894-1898).

DTE Electric is also leveraging AMI technology to enhance customer benefits and improve service quality in new ways including: (1) Power quality (AMI's ability to record voltage data at

⁵³ 3G is the third generation of cellular telecommunications technology, which is being succeeded by 4G (and by 5G in some instances).

customer locations enhances the electric infrastructure's engineering design process, and enables proactive resolution of electrical disturbances before they become a customer issue or complaint); (2) Customer Excellence Program (CEP; AMI data regarding customer service interruptions is used to proactively resolve service delivery issues); (3) Closed Loop Customer Communications (AMI will be used to confirm appropriate electrical service for each customer site following service restoration work); (4) Meter-Service Accuracy Detection (AMI detects if an incorrect meter type is installed at a customer site, or if certain service disruptions occur that the customer might not notice, but which could affect electrical service and billing); (5) Electric grid phase modeling (DTE Electric is collecting average voltage samples to create voltage signatures of the quality of electric service at the customer site, and starting to use the data to improve the reliability of the electric distribution network, determine which customers are fed from which transformers, and to create predictive maintenance algorithms); (6) Critical Data Provider for Advanced Distribution Management System (ADMS) Functions (AMI data is incorporated into ADMS Outage Management (OMS) functions, and essential to enable ADMS Distribution Management (DMS) functions including VoltVar Optimization (VVO), Conservation Voltage Reduction (CVR), and Fault Locating, Isolation and Service Restoration (FLISR) functions); (7) Hazard Detection (The Company is continuing to build on results of pilot studies to indicate possible human hazard cases from potentially broken conductors); and (8) Load Control (The Company is continuing to replace load control devices used to support customers that utilize interruptible service billing plans) (7T 1898-1901). There are also additional future benefits of AMI related to grid modernization as described in the Grid Distribution Plan (GDP) (Smith, 7T 1901).

The Commission previously "direct[ed] DTE electric to provide the Staff with the actual yearly realized benefits of AMI along with the forecasted benefits for past years in the reporting"

(May 8, 2020 Order in Case No. U-20561, p 212). Accordingly, Exhibit A-19, Schedule I1 compares actual AMI yearly realized benefits to previously-forecasted benefits from installation through 2020, for the benefits that the Company has been able to quantify. The Company also continues to comply with previously-established AMI reporting requirements, as reflected in Exhibit A-19, Schedules I, I1.1, and I1.2 (Smith, 7T 1901).

The main categories of benefits included in Exhibit A-19, Schedule I1.2 result from improved operational efficiencies, better revenue management, better theft protection, and energy savings. Mr. Smith further explained that energy savings is a new category that was not included in the original AMI cost-benefit analysis, and which reflects that AMI meters provide insights that are an integral part of Energy Waste Reduction (EWR) and Demand Response (DR) programs. There are also other AMI benefits that are not included in Exhibit A-19, Schedule I1.2. For example, AMI infrastructure and the development of the Enterprise Data Analytics data lake (software and data platform) has enabled the Corporate Energy Forecasting (CEF) team to utilize more granular data, which has benefitted forecasting processes through increased accuracy and/or reduced volatility in results, as well as providing additional forecasting capabilities (Smith, 7T 1902-1903).

Mr. Smith supported capital investments for AMI technology enhancements including capital spending required for Cell Relay (CR)⁵⁴ 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

⁵⁴ 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).

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).

In Case No. U-20561, the Company proposed an AMI Communications Upgrade project. The Commission agreed with Staff's proposed \$2 million disallowance for an additional 300 CRs. (May 8, 2020 Order in Case No. U-20561, p 94).

The Company now seeks a recovery of \$0.6 million for actual spending on the approved program, but not the disallowed CRs. Mr. Smith explained in part:

The Company completed the residential communication update in 2020. The Company was able to successfully complete the upgrade with 2,751 CRs at a total cost of \$30.7 million. The Company is no longer requesting recovery of the 300 relays previously disallowed by the Commission. In the U-20561 order, the Commission approved \$30.1 million. The Company is seeking recovery of \$0.6 million for the difference between the actual spend of \$30.7 million and the authorized amount of \$30.1 million. [Smith, 7T 1907.]

Staff recommended disallowing the \$0.6 million, reasoning that there was a lack of evidence that customers are dissatisfied with their service, the money was unnecessarily spent because the overall meter read rate is high, and the Commission rejected the expense in Case No. U-20561 (Rogers, 8T 5366-5367 32-33).

Mr. Smith disagreed, first clarifying that the project was approved in Case No. U-20561, as indicated in the quote above. More specifically, in Case No. U-20561, the Commission approved \$30.1 million of projected capital for the AMI Meter Communications Upgrade project and disallowed two amounts: (1) \$2 million for additional CRs, and (2) \$4.5 million for PQ meters. The \$0.6 million sought here is not related to either disallowed investment. Instead, the Company completed the approved project with an actual spend of \$30.7 million (\$0.6 million over the estimated and approved \$30.1 million). The overage was primarily due to higher labor costs than originally estimated to deploy the AMI units (Smith, 7T 1916-1917).

He further explained that while customer complaints did not drive the project, when leaves grow in May, this vegetation density is enough to interrupt approximately 13,000 AMI meters' connection to the network. Due to the loss of electric usage data, billing must be estimated based on prior usage and seasonal trending. When these customers complain about estimated bills, it reinforces that AMI performance is poor in the area. These customers also do not have other benefits of AMI meters (Smith, 7T 1914-1915).

Mr. Smith further testified that the high meter read rate that Staff referenced is an average across all 2.6 million AMI meters. The meter read rate for the approximately 13,000 seasonally-affected customers was effectively zero during the six months of higher-density vegetation. The unrecovered investment was used to remediate pockets of meters where the Company lost communications with meters (dead zones affecting approximately 13,000 customers) so that customers continue to have AMI benefits (summarized above; for example, actual reads because otherwise the Company would have to estimate bills, which drives customer complaints, or deploy on-site special meter reading at additional O&M costs). Thus, it was appropriate to close the gap for these disadvantaged customers. Extending AMI technology to them also ensures that they have access to AMI's benefits, and better positions the Company to support the next-generation transformation of the grid (Smith, 7T 1907-1919, 1916).

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 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. Therefore, the investment is reasonable and prudent, and should be approved (Smith, 7T 1911-1912, 1916-1917).

Staff previously proposed a disallowance for PQ meters as insufficiently supported. The Commission agreed with the proposed disallowance, explaining that it was “not averse to investments of this type,” and suggesting that the Commission would like to see evidence “that the investment dovetails with the overall benefits afforded by the AMI system,” as well as “a better view and understanding of the state of power quality on the system as a whole” and “the current status of systemic power quality” (May 8, 2020 Order in Case No. U-20561, p 93).⁵⁵

Staff maintained its position that the installation of advanced PQ meters is not adequately justified, and recommended a \$3.9 million disallowance (Rogers, 8T 5367-5368). DTE Electric understands the reasoning about a lack of evidence demonstrating benefits, but requests that the Commission recognize that the Company is in an evidentiary dilemma – it cannot provide evidence of actual customer benefits from the investment until it makes the investment that will give it the capability to show 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).

⁵⁵ The Company also proactively addresses voltage concerns by, among other things, running the AMI voltage query three times per day, and creating high-voltage cases in the Company’s Outage Management System (OMS) for dispatching shortly after the query is completed (Robinson, 7T 1574-1576).

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).

Thus, the PQ meters were an appropriate investment made at an appropriate time for the Company's highest-load customers, and the \$3.9 million should be approved. If the Commission continues to disagree, however, then it should at least approve \$698,000 to cover the costs of replacing 3G meters with non-PQ 4G meters (Smith, 7T 1917-1918).

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 is 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 based solely on historical spend, rather than the Company's more detailed forecasting for the bridge and test year periods (Exhibit A-34, Schedule Y6). Staff did not account for (1) the slowdown in new business installations due to volatility attributable to COVID (disruptions in crew availability in 2021), 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, and (3) the impact of the Company's night patrol program (further discussed elsewhere regarding Community Lighting O&M), which is proactively identifying outages resulting in a corresponding higher outage restoration spend. Staff also apparently did not consider forecasted capital expenditures (\$1 million per year) for the Company's proposed cable replacement program (which is new and not reflected in historical spend) to replace failing in-service cable (Bellini, 7T 1774-1775). Therefore, the Company's capital expenditures should be fully approved.

MI-MAUI witness Bunch suggested a transition to networked lighting controls (8T 3474). The Company disagrees because networked lighting controls are expensive⁵⁶ with an unproven track record. It is also important to keep in mind that the reason for such a system would be to provide notice when a light is non-operational. In other words, it is a detection system, similar to the Company's night patrol program (further discussed elsewhere regarding Community Lighting O&M), and its significant additional costs are not justified (Bellini, 7T 1755-1758).

Mr. Bunch further asserted that removal costs should be less than installation costs, and implied that the Company's removal costs are unreasonable based on an example from Ann Arbor witness Hess where this was not the case (Bunch, 8T 3482). Mr. Bellini explained that it is possible that removal costs could be higher than installation costs, but for reasons other than Mr. Bunch suggested. Company assets are recorded using historical cost. Therefore, an asset could be placed in service in 1980 (with 1980 installation costs) and removed in 2022 (with 2022 removal costs). (Bellini, 7T 1767)⁵⁷

⁵⁶ The Company received two third-party pilot proposals in 2020, which when extrapolating the capital cost only per node for 165,000 Company-owned nodes plus labor, were both estimated to be over \$20 million (Bellini, 7T 1757).

⁵⁷ The Company also disagrees with Mr. Bunch's recommendation to stop charging CIAC and include costs as part of depreciation expense (Bunch, 8T 3483) because this would result in the Company recording a higher expense on its books and charging all remaining customers for the cost of removal, which would be an unfair subsidization among customers (Bellini, 7T 1767).

Also, each removal job is unique and specific to the scope of work requested. The example from Ann Arbor witness Hess concerned an estimate to remove a single light post that was located between posts being serviced by the same underground electrical feed. 500 feet of new cable needed to be re-fed through an underground bore between the two remaining posts to continue the electrical service. Thus, the estimate reflects not just the removal of the single light, but also the heavy machinery and significant amount of cable to reconnect service (Bellini, 7T 1768; Exhibit A-34, Schedule Y4).

Ann Arbor witness Hess also suggested that a quote that Ann Arbor received for converting all remaining Company-owned lights to LED was cost prohibitive (8T 3496). The Company maintains that its estimates for conversion are appropriately based on costs. Whether a municipality may consider conversion affordable depends on various factors, but even with Mr. Hess' example, the estimated payback period resulting from efficiencies from converting to LEDs would be 5.3 years (Exhibit MAUI-28). A consistent number of communities are also proactively converting all, or significant portions, of their lighting to LED (Bellini, 7T 1769-1770).

Mr. Hess also suggested that the Company is routinely too slow in installing streetlighting after it is requested, referencing three jobs that took over a year (H 8). Mr. Bellini explained that this timeline is not typical. All three projects were delayed approximately 10 months due to (1) the time it took to receive a signed contract from Ann Arbor, and (2) the time it took to receive a permit from Ann Arbor (Bellini, 7T 1770-1771).

6. 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)).⁵⁸

In addition, DTE Insight is a stand-alone program developed around a mobile application that aims to drive customer behavior with the goal of reducing both overall energy (gas and electricity) consumption and electricity demand during peak hours (Nguyen, 7T 1604; Farrell, 1661). Total DR and DTE Insight capital spending was \$6.5 million in 2020, and is planned to be \$25.2 million in the 22-month bridge period ending October 31, 2022, and \$10.4 million in the projected test year (Exhibit A-12, Schedule B5.6, page 1, line 6, columns (b), (e), and (f)).

Company witness Mr. Farrell described the overall purpose, importance, and regulatory framework of the Company's DR programs and Pilots (7T 1653-1656) and provided an overview of DTE Electric's DR portfolio (7T 1656-1658, 1676-1677).

The IAC program (CoolCurrents) was first approved in the December 11, 2015, Order in Case No. U-17767, pp 35-36). It is a dispatchable DR program in which a direct Load Control Device (LCD) is installed on a customer's air conditioning unit or central heat pump in exchange for a discounted energy charge on the associated usage under the Tariff D1.1 Interruptible Space Conditioning Service Rate. The Company replaced a cumulative total of 166,568 units as of October 31, 2021, with a goal of replacing approximately 214,000 by the end of the projected test year. DTE Electric is forecasting to spend \$6.7 million during the bridge period of January 2021

⁵⁸ 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).

through October 31, 2022, and \$3.3 million for the projected test year period ending October 31, 2023 (Farrell, 7T 1661-1665; Exhibit A-12, Schedule B5.6, page 1, line 1, columns (e) and (f)).

The PCT program (SmartCurrents) is a form of DR known as Variable Peak Pricing (VPP), that is available to residential and commercial customers, and requires customers to enroll in the Dynamic Peak Pricing (DPP) tariff (D1.8 rate). By enrolling in the program, the customer receives a free PCT and allows the Company to send a pricing signal to the PCT that raises the customer's thermostat by 4 degrees on critical peak days when the cost per kWh increases to \$0.95 between the hours of 3:00 P.M. and 7:00 P.M. The customer retains the option to override the temperature set point. Mr. Farrell discussed PCT history including the evolution of the initial pilot to the current program. The Company had enrolled 17,691 customers on PCTs as of October 31, 2021 and expects a total of 25,000 enrolled customers by the end of the projected test period. The Company forecasts \$8.2 million of capital expenditures in the 22-month bridge period ending October 31, 2022, and \$3.5 million in the projected test period (Farrell, 7T 1665-1672; Exhibit A-12, Schedule B5.6, page 1, line 2, columns (e) and (f)).

Mr. Farrell also discussed the Bring Your Own Device (BYOD) program (Smart Savers), which previously was a pilot and is available to residential and commercial customers who already have an installed Wi-Fi enabled smart thermostat. This program enables the Company to send a control signal to raise the thermostat's set point by up to four degrees during Smart Savers Events (7T 1672-1695). Other on-going or future DR pilots include (1) the DTE Smart Charge pilot, which is a Plug-in Electric Vehicle (PEV or EV) pilot in partnership with EPRI's Transportation Program; (2) the Peak Time Savings (PTS) pilot (formerly known as Peak Time Rebates (PTR)) for residential customers; (3) implementation plans for a battery energy storage pilot for or in conjunction with C&I customers; (4) evaluating a residential generator pilot and an interruptible

window air conditioner pilot; and (5) supporting the development of Non-Wire Alternatives (NWA) pilots that are being developed under the leadership of the Distribution Operations organization (Farrell, 7T 1672-1695). DTE Electric is forecasting to spend \$5.0 million during the bridge period of January 2021 through October 31, 2022, and \$2.8 million for the projected test year period ending October 31, 2023, for these Other DR programs and pilots (Farrell, 7T 1695-1696; Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (e) and (f)).

Mr. Farrell further explained that the current non-interruption penalty for interruptible customers is \$50 per kW applied to the highest 60-minute integrated interruptible demand created during the interruption period. The Company proposes to change the penalty to be the higher of \$50 per kW applied to the highest 60-minute integrated interruptible demand created during the interruption period, or the actual damages incurred by the Company. The Company proposes this change to ensure that non-performing interruptible customers are not subsidized by other PSCR customers, because the possibility presently exists that MISO penalties could exceed the penalties paid by non-performing interruptible customers. The Company proposes to first use the penalties to offset any MISO-allocated penalties that flow through the PSCR process, to ensure that PSCR customers are held harmless. Any excess penalty revenues would then be allocated to improving DR programs (Farrell, 7T 1696-1697).

Company witness Mr. Nguyen further explained that DTE Insight is a comprehensive program that centers on a mobile application (DTE Insight App) that is integrated with AMI to help residential customers monitor and manage their energy use. When paired with an Energy Bridge (EB) device, the DTE Insight program participants can obtain real-time energy information and manage connected smart devices such as thermostats. For 2021, DTE Insight participants are forecasted to save 40,170 MCF of natural gas, and 2,201 MWh of electricity. The Company plans

to manage the existing EB inventory (69,790 as of October 31, 2021) to fulfill ongoing EB requests expected for 2022 and 2023. DTE Electric is forecasting to spend \$5.4 million during the bridge period of January 2021 through October 31, 2022, and \$0.7 million for the projected test year period ending October 31, 2023 (Nguyen, 7T 1605-11; Exhibit A-12, Schedule B5.6, page 1, line 5, columns (e) and (f)).

i. 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)).

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).

ii. 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).

7. 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)).

DTE Electric has a robust IT capital investment planning process, which is known as the Annual Planning Cycle (APC), 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 \$250,000.⁵⁹ 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). As Mr. Sharma explained:

In addition, the Company is providing detailed business case documents for each project to be completed in 2020-2022 as workpapers. The business cases reflect the completion of the detailed scoping through our Annual Planning Cycle (APC) business case approval process. Exhibit A-24 Schedule N1 contains the “Executive Summary” portion derived from those workpapers. For projects to be completed in 2023, the Company is providing a business case summary for projects that have completed the APC prioritization process. Exhibit A-24 Schedule N1 contains the “Executive Summary” portion derived from the business case summaries. [7T 1927.]

Company witness Mr. Sharma provided an overview of the most significant investments in each of the IT capital portfolios listed on Exhibit A-12, Schedule B5.7, page 1, lines 2-10, organized into the categories of Regulatory Compliance, Sustainment, Return-to-Health, IT Enhancements,

⁵⁹ 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).

Strategic, and IT Projects less than \$250,000, as indicated above and summarized at Exhibit A-12, Schedule B5.7, page 1, lines 13-18. In summary:

1. The Corporate Applications Portfolio encompasses assets used by the enterprise to execute critical internal business functions. It supports business units such as Human Resources, Finance and Controller, Legal, Supply Chain and Facilities, and IT assets used by the entire enterprise (Sharma, 7T 1935). Capital expenditures were \$12.8 million in the 2020 historical test year, and are projected to be \$22.8 million in the 22 months ending October 31, 2022, and \$12.5 million in the projected test year (Sharma, 7T 1935-1936; Exhibit A-12, Schedule B5.7, page 1, line 2, columns (b), (e), and (f); and Schedule B5.7.1, line 30, columns (d), (g), and (h)). Details regarding individual projects are at 7T 1936-1963.
2. The Customer Service Portfolio consists of key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform (Sharma, 7T 1963). Mr. Sharma supported capital expenditures in the Sustainment and Return-to-Health categories, which were \$14.7 million in the 2020 historical test year, and are projected to be \$31.4 million in the 22 months ending October 31, 2022, and \$24.7 million in the projected test year (Sharma, 7T 1963-1964; Exhibit A-12, Schedule B5.7, page 1, line 3, columns (b), (e), and (f); and Schedule B5.7.2, line 26, columns (d), (g), and (h)). Details regarding projects in these categories are at 7T 1964-1987.

Company witness Ms. Pizzuti supported capital investments included in the Customer IT Portfolio in the Regulatory & Compliance, IT Enhancements, and Strategic categories were \$41.8 million in the historical test year, and are projected

to be \$97.6 million in the 22 months ending October 31, 2022, and \$56.4 million in the projected test year (Pizzuti, 7T 2151-2152, 2165; Exhibit A-12, Schedule B5.7, page 1, line 4, columns ((b), (e), and (f), and Schedule B5.7.3, page 1, line 61, columns (d), (g), and (h)). These investments reflect a prioritized mix of projects across customer journeys that includes investments in digital channel enhancements, new digital and voice channel functionality, enhanced customer communication platforms, new customer-focused rates and programs, and expanded investments in supporting data platforms and analytics (Pizzuti, 7T 2165). Details regarding investments are at 7T 2166-2179 (Regulatory & Compliance), 7T 2179-2187 (IT Enhancements), and 7T 2187-2237 (Strategic).

3. The Plant and Field Portfolio consists of the business systems that are used by the Distribution Operations (DO), Fossil Generation, Generation Optimization, and Fermi organizations (Sharma, 7T 1988). Capital expenditures were \$19.4 million in the 2020 historical test year, and are projected to be \$71.9 million in the 22 months ending October 31, 2022, and \$36.9 million in the projected test year (Sharma, 7T 1988-1989; Exhibit A-12, Schedule B5.7, page 1, line 5, columns (b), (e), and (f); and Schedule B5.7.4, line 45, columns (d), (g), and (h)). Details regarding individual projects are at 7T 1989-2036.
4. The Information Technology for IT Portfolio consists of capital projects that represent investments made within IT for the enterprise as a whole, or that enable the functioning of the IT Department in support of the overall Company (Sharma, 7T 2036). Capital expenditures were \$8.3 million in the 2020 historical test period, and are projected to be \$16.1 million in the 22 months ending October 31, 2022, and

- \$7.5 million in the projected test year (Sharma, 7T 2036-2037; Exhibit A-12, Schedule B5.7, page 1, line 6, columns (b), (e), and (f); and Schedule 5.7.5, line 30, columns (d), (g), and (h)). Details regarding individual projects are at 7T 2038-2064.
5. The Information Protection & Security (IPS) Portfolio is focused on reliability of security infrastructure and improving the Company's overall security posture in IT and Operational Technology (OT). (Sharma, 7T 2064). Capital expenditures were \$3.3 million in the 2020 historical test year, and are projected to be \$4.8 million in the 22 months ending October 31, 2022, and \$4.2 million in the projected test year (Sharma, 7T 2065-2066; Exhibit A-12, Schedule B5.7, page 1, line 7, columns (b), (e), and (f); and Schedule B5.7.6, line 15, columns (d), (g), and (h)). Details regarding individual projects are at 7T 2066-2078.
 6. The Infrastructure Operations Portfolio is responsible for the design, implementation, and secure operation of the Company's overall IT infrastructure (Sharma, 7T 2078). Capital expenditures were \$27.5 million in the 2020 historical test year, and are projected to be \$30 million in the 22 months ending October 31, 2022, and \$15.9 million in the projected test year (Sharma, 7T 2078-2079; Exhibit A-12, Schedule B5.7, page 1, line 8, (b), (e), and (f), and Schedule B5.7.7, line 26, columns (d), (g), and (h)). Details regarding individual projects are at 7T 2080-2101.
 7. The Enterprise Data & Analytics (EDA) Portfolio is responsible for the construction of the Company's cloud-based and on-premise data platform to enable analytics to drive business value. This requires a data platform for data storage and processing, along with software to manage the data and usage. In order to support data users, the Company created a team to enable the infrastructure, build integrations to source

systems, and subsequently organize, describe, and document the data available on the platform. EDA's mission is to dependably deliver timely, secure, high-quality data to business partners throughout DTE (Sharma, 7T 2101). Capital expenditures were \$8.1 million in the historical test year, and are projected to be \$4.7 million in the 22 months ending October 31, 2022, and \$1.5 million in the projected test year (Sharma, 7T 2101-2102; Exhibit A-12, Schedule B5.7, page 1, line 9, columns (b), (e), and (f); and Schedule B5.7.8, line 11, columns (d), (g), and (h)). Details regarding individual projects are at 7T 2102-2106.

8. The Innovations Portfolio applies innovation to deliver rapid value with shorter development cycles and time-to-value, to addresses customer and business challenges that cannot be solved with traditional approaches (Sharma, 7T 2106). The Company seeks to recover the \$3.7 million that it spent on Innovation investments in the 2020 historical test year (Sharma, 7T 2107; Exhibit A-12, Schedule B5.7, line 10, column (b), and Schedule B5.7.9, line 8, column (d)). Details regarding the Innovation project are at 7T 2107-2112.

In addition to providing data on new investments, the Company also addressed the cost variance for capital investments greater than \$0.5 million, approved in the prior rate case, where there is more than a 20% variance from the projected budget and for which the Company is seeking additional recovery. The Company spent \$136.2 million of capital on IT projects in 2019, compared to the \$89.6 million authorized in Case No. U-20561 (Sharma, 7T 2112; Exhibit A-24, Schedule N2, line 1). Mr. Sharma sponsored Exhibit A-24, Schedule N2.1 identifying the portion of the variance that occurred in each project, and explained the major factors that contributed to the variance in each project (7T 2113-2121). Similarly, for 2020, the Company spent \$139.6 million

of capital on IT projects, compared to \$98.6 million authorized in Case No. U-20561 (Sharma, 7T 2121; Exhibit A-24, Schedule N2, line 2). Mr. Sharma sponsored Exhibit A-24, Schedule N2.2, and explained the 2020 variances (7T 2122-2124). Ms. Pizzuti further explained the 2019 (\$16.2 million) and 2020 (\$23.5 million) variances for projects in the Customer IT Portfolio (7T 2238-2247).

i. IT Projects with a Level 1 Cost Estimate

Staff proposed “a complete [\$50.76 million] 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 Company disagrees, emphasizing that it 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).⁶⁰

Staff’s assertion that “Level 1 costs estimates are immature and solely a concept being screened for feasibility within the Company’s annual expense plan” (Rogers, 8T 5343) misconstrues the Company’s Annual Planning Cycle (APC) Process. Investments are marked as “Level 1” only because of the timing of the estimate in the multi-year APC process, which should not lead to an assumption that known cost details are insufficient or will result in significant variance (Sharma, 7T 1927-1928, 2129).

⁶⁰ The Company similarly disagrees with Staff’s further comments indicating a lack of supporting information, and recommendation to provide a more detailed cost estimation practice in future rate cases (Rogers, 8T 5347). Staff’s comments neglect, among other things, that the Company provided business case cost estimation worksheets with detailed breakdown of cost-by-cost type and the new additional project details exhibit with cost breakdown as requested by Staff in previous cases (Sharma, 7T 2132-2133).

Staff's assertion that Level 1 estimates "do not include a cost breakdown" is inaccurate because the Company submitted the 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 \$34.7million, 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).

ii. IT Projects with a Level 2 Cost Estimate

Staff proposed a 20% (\$36.0 million) capital expense disallowance (\$19.6 million in the ten months ending October 31, 2022; \$16.4 million in the projected test year) for 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 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) are in progress so the cost estimates are closer to a Level 3 cost estimate (Sharma, 7T 2134).

The Company also disagrees with Staff’s 20% disallowance as 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).⁶¹

⁶¹ 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).

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 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).

Therefore, Staff's proposed 20% disallowance should be rejected as unsupported and contrary to 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).

iii. IT Projects without Business Cases

Staff 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 agrees 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).

iv. 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.

a. 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). The Company disagrees and maintains that the disallowance should be rejected based on the Company's capitalization policy. Additionally, the \$7.71 million proposed by Staff included a duplicative disallowance for the Company's DERMS project. (Sharma, 7T 2138-2139). Staff also proposed a double \$2.54 million disallowance for the DERMS project with regard to Distribution Operations. The Company agrees that there should be a reduction from the IT forecast, but the Commission should reject the proposed duplicative disallowance from the Distribution Operations forecast (Pfeuffer, 4T 486-487).

Staff incorrectly assumed 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 examples of new functionality for each project. The ClickSoft project includes both 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).

Staff also indicated a concern that the Fermi Enhancement project's scope includes "developing data mapping strategy, importing and loading data into the new platform, and validating data," which Staff thought met the definition of data conversion so they should be expensed to O&M (Wang, 8T 5229). Company witness Ms. Uzenski disagreed, explaining that the data migration efforts importing and loading data into the new platform and validating data have been appropriately accounted for as an O&M expense. Developing the data mapping strategy is considered part of the project's design phase; without it the software would not be able to be used (Uzenski, 7T 2795-2796).

b. Staff's disallowance proposal.

Staff proposed a \$11.2 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). In addition to the discussions above that capital expenditures should be approved, the Company disagrees with Staff's \$11.2 disallowance 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 expense 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 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). (Uzenski, 7T 2777-2778).

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 disagrees with Staff's 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).

v. IT Projects Historical Spend Analysis

Staff proposed a \$1.85 million disallowance based on calculations shown at Wang, 8T 5231-5232. The Company disagrees with this suggested disallowance because Staff extrapolated data from a 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).

vi. Other Individual IT Project Disallowances

With regard to Staff's indicated perspective for evaluating individual IT projects (*e.g.*, whether the project provides value to customers in terms of cost savings, safety and/or reliability), Ms. Pizzuti explained that the Company applies these considerations when evaluating IT projects for investment. 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).

Staff further suggested that the Company inappropriately compared itself to, and identified opportunities for improvement through, the best practices of non-utility companies (Armstrong, 8T 5489-5490). The Company disagrees because its goal of providing Distinctive Service Excellence (reflected for example in the DTE IT 5-Year plan) should not be limited to the best practices of peer utility companies, as customers will compare their experiences with DTE to experiences with their other non-utility service providers. Thus, the Company 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).

Staff recommended a disallowance for three IT projects (further discussed 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). Staff also proposed 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; 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).

a. Platform integration-SAP integration.

Staff proposed a complete disallowance (\$1.8 million in the bridge period; \$0.5 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 Company maintains that the project’s benefits and value are reflected in its name - integration. The project provides integration between the SAP systems (in the back end) and many of the Company’s Customer Service IT projects that provide an enhanced or new customer experience in its digital channels (the front end, and customer-facing system or technology). All front-end customer experiences where data is collected require integration and connection to the back-end SAP customer systems where data is processed and stored. With regard to considering alternative solutions, the SAP application is the best solution because these technology products are intended to work together seamlessly. Migration of functionality and capability from disparate legacy systems to a single SAP platform allows information from the Company’s operations to flow to front-end systems that directly serve the customer. (Pizzuti, 7T 2253-2254).

b. Automation application monitoring enhancement.

Staff proposed a complete disallowance (\$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 Company maintains that the project’s capability and benefits include 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. 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).

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

Staff proposed a complete disallowance (\$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). Staff neglects 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).

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.⁶²

d. Digital Experience Group (DEG).

Staff recommended a 60% (\$3.1 million) disallowance of historical 2020 capital costs, 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 Company disagrees because, as discussed above, benchmarking of utility peers demonstrates 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)

⁶² There is a discrepancy in Staff’s revenue requirement relating to the Advanced Customer Pricing Pilot (ACPP) and Time-of-Use (TOU) project. 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).

DEG; and an improved outage web experience and more accurate outage reporting from the Outage DEG investments confirmed the need of these projects and their customer benefits, justifying their full cost recovery (Pizzuti, 7T 2190, 2262-2263).

e. Digital transactional experience.

Staff proposed a 60% disallowance (\$3.87 million) in the bridge period, stating that Staff supported the concept of improving customer service, but “it is unclear how this expenditure line accomplishes this goal with reasonable costs” (Armstrong, 8T 5496). The Company disagrees because this project continues and builds on the success the 2020 DEG project as described above. The Company continued funding for the MIMO and Outage Digital Product Teams to add improvements that support higher engagement and completion rates in these transactions in 2021 by improving digital process flows, providing more and clearer information to the customer, and simplifying navigation of the web and mobile web experiences. The Digital Product Teams also expanded its scope of work to include Billing and Collection transactions, adding more digital and voice self-service solutions for our customers (Pizzuti, 7T 2264).

As described by Ms. Pizzuti, these investments also generated favorable results and customer benefits. Investment in the MIMO Digital Transactional Experience, in conjunction with the Closed Loop Framework, led to higher customer satisfaction scores (as measured by Net Promoter Score) and First Contact Resolution. Continued focus on the Outage Digital Transactional Experience led to higher completion rates despite the record number of storms in summer 2021. Investment in the Collections Digital Transactional Experience by adding a Collections order tracker and the ability for customers to request a Promise-to-Pay Hold or to Restore Service in the IVR saw early, yet promising results with customers choosing to conduct these transactions in a self-service channel versus interact with a CSR, in line with peer benchmarking (Pizzuti, 7T 2264-2266; Exhibit A-44 Schedule II3).

f. Prepay billing program.

Staff has 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. 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).

g. 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 Company disagrees with all of the suggested reasons for a 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).

h. Network advanced metering infrastructure support.

Staff proposed a full disallowance (\$2.0 million in the historic period, \$4.6 million in the bridge period, and \$2.2 million in the projected test year) reasoning that the Company's meter read rate is already above the service quality standard (Rogers, 8T 5350). The Company disagrees because meter read rate improvements are an indirect benefit of maintaining Network Advanced Metering Infrastructure (AMI), but the reason for the investment is to replace aging infrastructure (Sharma, 7T 2141-2142; Exhibit A-42, Schedule GG2 DR – 3.6).

The prudence of the investment is further reflected by work planned and executed in 2021 and 2022. Hardware-related spend totals \$2.67 million, consisting of (1) \$1.75 million for the procurement, configuration, installation and monitoring of 300 Tropos Mesh Routers that must be replaced for various reasons such as failure due to storm damage, and (2) \$0.92 million for the procurement, configuration, construction, mounting, installation, and monitoring of Cambium Medusa Point to Multipoint Backhaul equipment to replace the current WiMAX wireless backhaul systems that the Federal Communications Commission (FCC) has deregulated. Due to spectrum reallocation, cellular retail providers have been installing equipment that causes interference with the existing communications systems, which must be replaced to provide an interference-free communication system for AMI. Staff's proposed disallowance is also based entirely on past testimony from Case No. U-20561, and completely ignores the current project justification (Sharma, 7T 2091-2093, 2141-2142).

i. Controllers financial planning tool.

Staff recommended a complete disallowance (\$2.187 million in the bridge period and \$0.613 million in the projected test year) reasoning that the Company was still investigating

alternatives when it filed this case, and should seek recovery when it has a more complete plan for implementation (Rogers, 8T 5352). The Company disagrees because 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).

j. Virtual desktop infrastructure.

Staff recommended a total disallowance (\$0.203 million in the bridge period and \$0.252 million in the projected test year) stating that "this project is no longer necessary and its purpose of matching virtual desktop infrastructure to an increased remote work demand due to COVID-19 is becoming irrelevant" (Rogers, 8T 5357). To the contrary, while the COVID-19 pandemic initiated the demand to enhance the Virtual Desktop Infrastructure, the Company will continue to operate with employees working from home or in a hybrid work model, and the investment is required (Sharma, 7T 2096-2097, 2143-2144).

k. Command center stand up.

Staff proposed a total disallowance (\$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 a lack of evidence regarding how the project will benefit safety or reliability of electric service to customers (Rogers, 8T 5358-5357). The Company disagrees. 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. This 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).

1. GRC tool expansion for regulatory assets.

Staff proposed a complete disallowance (\$0.103 million in the historical year and \$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).

Finally, Staff indicated that it does not recommend a disallowance of the gas portion of shared IT assets (Rogers, 8T 5370), which presumably means that Staff is not reducing the shared asset revenue to account for Staff's proposed disallowances to IT shared assets. The Company forecasted \$57.2 million of revenue from shared assets, assuming the capital projects in this case are approved (Exhibit A-13, Schedule C3, line 14). 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.

vii. AG’s proposed disallowances

a. 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).

It appears the AG’s proposals are 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-23.01.⁶³ 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).

b. Voluntary prepay billing program.

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

⁶³ 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).

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).

c. Digital transactional experience and journey work product transformation teams.

AG witness Coppola proposed a complete (\$6.5 million) disallowance in the bridge period of costs for 2021 for the Digital Transaction Experience project, and a \$4.2 million disallowance in the projected test year for the Journey Work Product Transformation Teams because the Company did not complete a traditional cost benefit analysis (8T 4808-4809). The Company disagrees because the Project Prioritization Score (PPS) is used in place of a traditional cost benefit analysis and is a critical component of the Company's IT APC process. The Company uses the PPS score to evaluate IT capital investments across multiple business benefit categories in addition to costs. Through discovery responses, the Company also provided a projection of cumulative call volume reduction and associated O&M cost benefits expected from investments in the Digital Product Teams and the IT digital transformational projects they support (see Exhibit AG-1.23, page 9), and referenced a supplemental attachment that was provided in response to Staff audit question CR-1.2 (Exhibit A-44, Schedule II5) that had the Company's most-recent forecasted cumulative call reduction of approximately 1.2 million calls from six transactions that provide the largest opportunity for migration of calls to the IVR and web from 2022-2025, and the associated cumulative O&M savings of approximately \$7 million (Pizzuti, 7T 2210-2211, 2272-2273).

8. Corporate Staff Group

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). Ms. Uzenski explained and supported the larger projects included in the categories on Exhibit A-12, Schedule B5.8, page 1, line 1 (Electric Vehicle Fleet), line 2 (Facilities Construction & Upgrade), line 3 (Facilities Renovation), line 4 (Service Center Optimization), line 5 (Headquarters (HQ) Energy Center), line 6 (Security Measures), line 7 (NERC-Critical Infrastructure Program), line 8 (Enterprise Automation), and line 9 (Other Miscellaneous). (Uzenski, 7T 2727-2738).

i. 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 Energy Center provides benefits by reducing the number of chillers from seven to four high-efficiency units, providing energy savings estimated at 2.5 million kWh/year. The Energy Center is also easily accessible with reduced maintenance costs and labor needs. Regarding natural gas fired steam boilers, the Company believes that it can better control steam costs and improve operational effectiveness by using a system that it owns and operates (Uzenski, 7T 2734).

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).

AG witness Coppola 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).

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).⁶⁴

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)).

As indicated above, the Company can agree to Staff's alternative recommendation using the updated \$1.4 million difference (Uzenski, 7T 2784). Therefore, the reduction to project costs should be \$0.7 million, and the additional capital expenditures should be approved.

ii. Enterprise Automation

Enterprise Automation engages in automation, digitalization, and process improvement initiatives across the Enterprise. Robotic Process Automation (RPA) software is used to program

⁶⁴ Staff also recommended that the Company break out the HQ Energy Center O&M so it can be evaluated in the Company's next rate case (Kindschy, 8T 5481). The Company generally agrees and will establish new accounts to capture most of the O&M expense related to operating the HQ energy Center; however, some expenses are part of broader work streams related to the entire downtown campus, and it is not practical to track the amount attributable to the HQ Energy Center (Uzenski, 7T 2780).

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 \$0.6 million for 2021 (as not spent), \$9.2 million for the ten months ending October 31, 2022, and \$11.0 million for the projected test year, as allegedly not justified (Rogers, 8T 5362-5363 28-29). The Company can agree with the \$0.6 million reduction for 2021, but otherwise disagrees with the remaining \$9.2 million and \$11.0 million disallowances as suggested by Staff (Uzenski, 7T 2784).

Staff indicated that it did not consider bridge period capital expenditures to be adequately justified due to a lack of cost information. Staff's concern is addressed by Exhibit A-43, Schedule HH5, which shows the most recent forecast for 2022 including the project description, manual processing hours saved, and cost estimates that were not available when the Company responded to Staff's discovery request (Uzenski, 7T 2784).

Staff also proposed a total \$11.0 million disallowance for 2023, reasoning that the Company had not yet determined 2023 opportunities (Rogers, 8T 5364). The Company disagrees with this disallowance because it anticipates spending \$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. Staff also noted that Enterprise Automation has grown 63% since its inception (Rogers, 8T 5364 30), so the assumption that spending will remain flat from 2022 to 2023 is conservative and reasonable. Furthermore, Staff does not dispute the nature of Enterprise Automaton spending, including \$9.9 million of actual spending in 2021, as discussed above. Therefore, the Commission should fully approve Enterprise Automation capital expenditures, except for \$0.6 million for 2021 (Uzenski, 7T 2784-2785).

9. Marketing Pilots

i. Charging Forward

The Commission previously approved the Company's proposed Charging Forward program regarding electric vehicles (EVs), with some modifications, stating in part:

[T]he Commission finds that DTE Electric is authorized to create a regulatory asset to recognize deferred EV program costs with the amortization of those costs over five years beginning the year after the costs are incurred. Further, the Commission authorizes the company to include recovery of the resulting amortization expense in rates and include the deferred net unamortized balance of EV program costs in rate base. However, the program costs will not actually be recovered until they have undergone a future reasonableness-and prudence review in a rate case. [May 2, 2019 Order in Case No. U-20162, p 115.]

The Company provided an update on Charging Forward in Case No. U-20561, where the Commission concluded:

Consistent with the May 2 [2019 Order in Case No. U-20162], the Commission agrees with the ALJ that the regulatory asset and capital expense should be approved for only the actual and reviewed expenses. Going forward, DTE Electric is authorized to begin the five-year amortization concurrent with review and approval in a rate case in lieu of amortization over five years beginning the year after the costs are incurred. [May 8, 2020 Order in Case No. U-20561, pp 165-66.]

Accordingly, Company witness Burns provided an update on the actual and estimated expenditures for Charging Forward's primary components, including (1) Direct Current Fast Charger (DCFC) Trials, (2) Customer Education & Outreach, (3) Residential Smart Charger Support, (4) Charging Infrastructure Enablement, (5) Additional Elements, and (6) Program Management (Burns, 7T 2404-2408). A complete status update of Charging Forward and justification for its components' costs is set forth in Exhibit A-29, Schedule T1 (Charging Forward's 2nd Annual Status Report that the Company filed in June 2021 in Case No. U-20162).

Total program costs were \$1.4 million in 2020, and are projected to be \$11.6 million for the 22 months ending October 31, 2022, and \$0 for the projected test year (Burns, 7T 2404-2405;

Exhibit A-12, Schedule B5.9, page 2, line 18, columns (b)-(e)).

ii. eFleets

To build on momentum of Charging Forward’s fleet component and avoid any gaps in available funding to support fleet electrification, on December 3, 2020, DTE Electric filed an application seeking *ex parte* approval of regulatory asset treatment and deferral authority for costs associated with Phase Two of its Charging Forward pilot program (Phase Two or eFleets). The Commission approved, stating in part:

[T]he Commission concludes that DTE Electric’s Phase Two proposal is reasonable and in the public interest as it will develop a better understanding regarding how C&I customers are incentivized to make the transition to clean EV technology, how the increased electrical load associated with EVs impacts electrical system usage and grid requirements, as well as the expected operational impacts of a wider commercial EV rollout. As such, the Commission authorizes DTE Electric to create a regulatory asset, not to exceed \$10.3 million, to recognize deferred Phase Two program costs with the amortization of those costs over five years beginning the year after the costs are incurred. [March 19, 2021 Order in Case No. U-20935, pp 4-5.]

Total eFleets projected costs are \$3.8 million in the 22 months ending October 31, 2022, and \$3.1 million for the projected test year ending October 31, 2023 (Burns, 7T 2411; Exhibit A-12, Schedule B5.9, page 3, line 23, columns (e) and (f)). Mr. Burns also provided additional details on eFleets’ components and costs (7T 2409-241310-14; See also, Exhibit A-12, Schedule B5.9.1 for a high-level summary of how eFleets meets the requirements for a pilot as provided in the February 4, 2021 Order in Case No. U-20645).

iii. Charging Forward Expansion

The Company proposes a Charging Forward Expansion. 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 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).

Mr. Burns provided background on the importance and status of transportation electrification (TE) (7T 2414-2418), and DTE's role in TE including guiding principles for the Expansion pilot's design (7T 24818-2424),⁶⁵ Mr. Burns also explained and supported the Charging Forward Expansion's primary components: (1) Customer Education & Outreach (7T 2425-2428), (2) Residential Level 2 Charging (7T 2428-2436), (3) Commercial Customer Support (7T 2436-2451), (4) Equitable Access to EVs (7T 2451-2468), and Program development (7T 2468-2474).

Total expected costs for the Expansion are projected to be \$0.4 million in the 22 months ending October 31, 2022, and \$17.4 million in the projected test year (Burns, 7T 2474; Exhibit A-12, Schedule B5.9, page 4, line 25, columns (e) and (f)). The overall net present value (NPV) net benefits to DTE customers for the Charging Forward expansion are estimated to be in the range of \$9.5 million to \$15.1 million (Burns, 7T 2481). Only about 7,150 EVs would need to be sold to cover the cost of the Charging Forward Expansion through the test period, significantly less than the 12,500 EVs that DTE attributes to the Expansion. This demonstrates the prudence of the investment to help accelerate TE, bring about the benefits of TE to all of the Company's customers, and further Michigan's climate goals (Burns, 7T 2483-2484).

The Company seeks to continue regulatory asset treatment for its existing Make-Ready Rebates, Residential Rebates, BYOC, and EV-Ready Builder Rebates elements, in accordance with the May 2, 2019 Order in Case No. U-20162, p 115 (quoted above). The Company also seeks

⁶⁵ The guiding principles are: (1) Reduce barriers to EV adoption; (2) Efficiently integrate EV load with the grid; (3) Help enable equitable access to EVs; (4) Test new technologies to prepare for widespread TE adoption in the future; and (5) Benefit the public interest and the State of Michigan (Burns, 7T 2419-2420).

accounting authority to defer and amortize the EV Rate Tool, Income-Eligible Rebates, Commercial CaaS (for the EVSE portion), and the Emerging Technology Fund. These elements are appropriate for regulatory asset treatment because they have the same characteristics as the existing regulatory asset elements – timing of spend is uncertain and spend can vary significantly year after year (Burns, 7T 2486, 2761).

There appears to be overwhelming support for the Company’s proposed Charging Forward Expansion, although some witnesses also suggested some modifications to what the Company proposed. The Company responds by topic below, with further details in Mr. Burns rebuttal testimony (7T 2505-2524).

The Company agrees in part with suggestions that it propose a permanent charging Forward program but will not be able to file a “final plan” as Staff suggests (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 Staff’s indicated expectation to see a “rigorous cost-benefit analysis” (Freeman, 8T 5545) 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).

Regarding Residential CaaS recommendations, the Company intends to use its existing supply chain request for proposal (RFP) approach with targeted follow ups to appropriately balance commercial considerations and customer satisfaction, which would seem to fully address Staff’s interest in specifying how contractors will be vetted and selected (Freeman, 8T 5541). The

Company's disagrees with MNSC's proposal that participants be required to choose between a time of use tariff and participation in the BYOC program (Jester, 8T 3827) because that proposal is based on the incorrect premise that the Company is phasing out its \$500 Residential Rebate program. The Company partially agrees with CP (Deal, 8T 4573-4576) and recognizes that having a minimum technical standard is important for customers. Therefore, the Company will require that chargers be ENERGY STAR certified in order to qualify for the residential elements. ENERGY STAR certified chargers are all UL-certified, and the list of chargers is accessible to customers through the ENERGY STAR website. The Company disagrees that chargers should be required to be networked because: (1) the cost of networked chargers is typically more, with ongoing networking fees; (2) the load management and data capabilities of networked chargers can also be obtained through vehicle telematics; and (3) customers participating in Residential CaaS and residential rebates could opt for a NEMA 14-50 outlet (since some cars come equipped with Level 2 plugs), which the Company considers the same as a non-networked charger (Burns, 7T 2510-2513).

Regarding Equitable Access to EVs, the Company is exploring options to reduce the cost of Income-Eligible Rebates and agrees to reach out and report on Equitable Access to EVs, which would seem to address Staff's indicated concerns (Burns, 7T 2513-2514).

The Company does not agree with various suggestions that the Commission require the Company to either update distribution hosting capacity maps or publish EV charging maps (Burns, 7T 2515).⁶⁶ 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-20147.⁶⁷ Proposals to update the map to include loading information raise concerns because load is dynamic and load maps are quickly outdated

⁶⁶ 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).

⁶⁷ Company witness Robinson further discussed the Company's HCA efforts (7T 1577-1582).

and involve significantly different analysis than DER hosting capacity. Any attempt to create an up-to-date and accurate EV hosting capacity map 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 disagrees with proposals that it only support Charging Hubs through a make-ready model and not full ownership for four reasons. First, the Company is seeking key learnings that it can best achieve through a full ownership model. Second, Make-Ready Rebates have been available for years, yet no third party has approached the Company to deploy centrally located infrastructure designed for medium and heavy-duty vehicles using the rebates. Third, the scope and scale of the Charging Hub proposed in this case is not comparable to the example that EVgo provided (Dumit, 8T 4695). Fourth, if the Commission does not approve DTE-owned Charging Hubs, then the Company would lose the ability to leverage potential opportunities in (1) applying for federal funds and achieving the key learnings at a lower cost to customers, and (2) complementing eFleets Advisory Services to site a Charging Hub near interested customers to allow them to pilot fleet electrification at a much lower cost. The Company is also confident that it will be able to identify sites that meet its buildout criteria and has strategically designed the Charging Hub rate to not undercut DCFC deployments for passenger vehicles (Willis, 6T 942-944; Burns, 7T 2515-2519).

The Company disagrees with MNSC's proposal that Make Ready Rebates be modified to ensure that make ready infrastructure is capable of supporting 350 kW DCFCs (Jester, 8T 3822) because "futureproofing" sites by assuming every charger is 350kW would unnecessarily create excess capacity for sites that might not use it for years (or ever). The Company similarly disagrees

with MNSC's proposal that DCFC rebates should require that the DCFC should support at least 150 kW charging rates (Jester, 8T 3822) because there are instances where that amount of output is either cost-prohibitive or not the best-matched solution for a specific use case (due to average dwell time). The Company believes that the existing DCFC tiered rebate structure allows for the right amount of charging output for the right use cases in the right places, as further reflected by historical results (Burns, 7T 2519-2520).

DTE Electric disagrees with MEIBC/IEI's proposal that the Company pursue a reliability standard of a minimum of 97% uptime per individual charger for a minimum of five years, reported across a 12-month period (Sherman, 8T 4387). The Company agrees with the importance of charger reliability but has two critical concerns. First, requirements for the National Electric Vehicle Infrastructure (NEVI) program are expected soon and will potentially include uptime requirements differing from MEIBC/IEI's proposal. Second, it is unclear how the Company would enforce such a requirement or who will (or should) be responsible for maintaining it because many parties have some responsibility for keeping chargers functioning. Therefore, the Company recommends aligning with NEVI requirements and allowing Network Providers to build their reporting capabilities in this regard rather than prematurely requiring it and burdening Charging Forward (Burns, 7T 2520-2521).

DTE Electric similarly disagrees with MEIBC/IEI's proposal that the Company should require that chargers receiving incentives make information about charging port status available through the various online EV charging web sites and/or apps that carry that information (Sherman, 8T 4388). This requirement would add unnecessary administrative burden, and the Company does not know how it would be enforced (Burns, 7T 2521).

In response to EVgo's assertion that the Company should develop a publicly available scoring rubric to provide transparency in its prioritization process (Dumit, 8T 4684), the Company agrees that if Make-Ready rebates are approved, then it will publish a scoring rubric for potential

site hosts to use within 30 days (Burns, 7T 2521-2522).

In response to statements about Commercial CaaS, the Company maintains that the targeted customer segments have little access to nearby EV chargers and low participation in Charging Forward so far, so the Company has proposed Commercial CaaS to see how it can effectively increase equitable access to charging. The Company believes this is an important part of the Charging Forward pilot phase. The Company will allow participants to select any charger from DTE Electric's qualified Make-Ready rebate list, and continue to refresh the list annually (Burns, 7T 2522-2523).

In response to CEO's recommendations to expand Transit Batteries (Cobaleda, 8T 3555), because this element is participant-funded and aligns well with increased Federal Transit Authority Low-No grant opportunities, the Company agrees and is willing to enroll more buses if the approved funding is sufficient to purchase additional transit bus batteries. The Company would also not oppose expanding Transit Batteries to include school buses (Burns, 7T 2523-2524).

iv. Residential Battery Pilot

The Company also 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 Company recognizes that the pilot otherwise did not receive broad support as currently structured. The Company disagrees with proposals by Staff (Matthews, 8T 5379) and others to include additional battery ownership structures within the pilot offering. 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).

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 maintains that Company ownership of the battery systems will best support the objectives of a residential battery pilot, and requests that the Commission approve the pilot as proposed.

VII. RATE OF RETURN

DTE Electric 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.

A. Capital Structure

1. Debt and Equity Balances

DTE Electric seeks to maintain its permanent capital structure of 50% debt and 50% equity (Lepczyk, 7T 1283, 1287, 1295; Exhibit A-14, Schedule D1. See also; May 2, 2019 Order in Case No. U-20162, pp 54-55; May 8, 2020 Order in Case No. U-20561, p 166). Staff (Ufolla, 8T 5083), the AG (Coppola, 8T 4817), and ABATE (Walters, 8T 3066) agreed. The only disagreement was by MEC/CUB, which proposed a capital structure consisting of 53% debt and 47% equity, which MEC/CUB claimed “equates to the average capital structure of the proxy group” (Garrett, 8T 3874).

Mr. Lepczyk disagreed, explaining that witness Garrett improperly relied on debt ratios of holding companies instead of operating companies. DTE Electric is an operating company, and its capital structure should be compared to other peer utilities. Holding companies face different risks, have higher cost of debt and equity, and are generally rated lower than operating companies. The average capital structure of operating companies in the proxy group is 52% equity, which is higher than the Company’s proposed capital structure of 50% equity (Lepczyk, 7T 1297-1298; Exhibit A-14, Schedule D1.1).

Mr. Lepczyk further explained that it is important to maintain DTE Electric’s capital structure due to the business and financial risks confronting the Company. Capital structure is critical because it determines a company’s access to credit markets (the *availability* of capital), and ability to raise capital at reasonable terms and rates (the *cost* of capital). Companies with more equity in their capital structures are less risky from a financial perspective, and generally have a greater ability to obtain capital, and lower required returns on equity and costs of debt than companies with weaker capital structures. If DTE Electric is unable to raise adequate capital, then

the Company will be unable to invest in the equipment and systems necessary to ensure efficient, reliable and safe electric service for its customers (Lepczyk, 7T 1284-1288).

Mr. Lepczyk further explained that the Company is using the previously-authorized capital structure to reduce the number of contested issues in this case; however, it would be reasonable and prudent to increase the equity ratio to 52%, which is the average equity ratio for the Company's peers (7T 1287-1288; Exhibit A-14, Schedule D1.1).

DTE Electric also had a 50% equity ratio on December 31, 2020 and is committed to maintaining a 50% equity ratio. DTE Energy made \$1.3 billion of equity infusions from 2016-2020, an equity infusion of approximately \$550 million in 2021, and will infuse the amounts necessary in future years to maintain a 50% equity ratio (Lepczyk, 7T 1288-1289).

In summary, DTE Electric needs a strong equity component of its capital structure to maintain adequate access to capital at the lowest reasonable cost during a period of significant capital investment. DTE Electric also continues to balance capital investment plans, credit metrics and customer rate impacts, while it continues to face significant ongoing and emerging business challenges, as further discussed below regarding ROE. Accordingly, the Commission should maintain DTE Electric's 50% equity ratio.

B. Debt Cost Rates

1. Long-Term Debt

DTE Electric recommends a 3.69% weighted cost of long-term debt, which was determined using the net proceeds method for each issue including the financing cost of the new issues (Lepczyk, 7T 1284, 1291-1292, 1295; Exhibit A-14, Schedule D2). Staff agreed (Ufolla, 8T 5085). So did the AG (Coppola, 8T 4818).

2. Short-Term Debt

DTE Electric recommends a 1.74% cost of short-term debt, which includes the interest rate on short-term borrowings and facility fees associated with the credit arrangements necessary for the issuance of short-term debt (Lepczyk, 7T 1284, 1293, 1295; Exhibit A-14, Schedule D3). Staff agreed (Ufolla, 8T 5085). So did the AG (Coppola, 8T 4818).

C. Return of Common Equity

Dr. Villadsen explained and recommended that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.25%.⁶⁸ 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).

Staff recommended 9.6% (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).⁶⁹ 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 account the interaction of capital structure (financial risk) and ROE. The changes in the capital markets (rising interest rates, high

⁶⁸ DTE Electric has no preferred stock (Exhibit A-14, Schedule D4).

⁶⁹ Walmart witness Perry disagreed with Dr. Villadsen's recommendation, but did not offer a specific proposal (Perry, 8T 4125).

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),⁷⁰ 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).

Her rebuttal testimony further discussed well-established financial principles, and responded to criticisms and apparent misunderstandings by Staff, the AG, ABATE and MEC/CUB

⁷⁰ The CAPM is a risk positioning risk positioning approach. Dr. Villadsen also used the Empirical CAPM (ECAPM) (7T 1343).

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,⁷¹ 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, 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

⁷¹Beta 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).

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).

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).

i. 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).

2. 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).

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

In DTE Electric's last general rate case, the Commission set DTE Electric's currently authorized ROE at 9.9%, explaining in part:

At this time, the Commission finds that an ROE of 9.90%, which is at the lower end of DTE Electric's proffered range of 9.75% to 10.75%, most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. . . .

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 previously set DTE Electric's ROE at 10.0%, stating that it "agrees with DTE Electric that factors such as volatility and uncertainty are currently particularly significant, and movements are more extreme in comparison to more stable historical periods" (April 18, 2018 Order in Case No. U-18255, p 32). The Commission maintained that ROE in DTE Electric's next-to-last general rate case, stating that it "was not persuaded that economic conditions have changed sufficiently, if at all, to warrant an increase in DTE Electric's ROE . . . [but 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 maintained the ROE at 9.9%, despite the Staff and AG proposing, and the ALJ’s recommending, lowering of DTE Gas’s ROE to 9.5%. The Commission explained in part that it “observes that an ROE of 9.90% falls within DTE Gas’s recommended range of 9.25-10.25% and is at the high end of the Staff’s proposed range . . .[and] the Commission agrees 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”).

The Commission also recently approved a settlement agreement including a 9.9% ROE and 50.75% common equity ratio for Consumers Energy (July 7, 2022 Order Approving Settlement Agreement in Case No. U-21148, p 2).

The Commission has also emphasized that in the present regulatory environment where rate cases are more common, proposals to radically reduce a utility’s ROE (particularly as ABATE and MEC/CUB have made) 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.

Dr. Villadsen 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 has decreased. 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. For example, in Case No. U-18014 (DTE Electric's general rate case prior to U-18255, which is discussed above), the Commission set DTE Electric's ROE at

10.1%, despite the ALJ recommending an ROE of 10.0%, in accordance with Staff's recommendation. In setting the 10.1% ROE, the Commission explained in part that "an ROE of 10.1% most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital. It also strikes an appropriate balance between the company's interest in investment and the interests of DTE Electric's ratepayers in safe, reliable and affordable energy . . . The Commission, in reaching its determination, also takes into consideration the company's unique circumstances and characteristics, rising interest rates and the standards set forth in *Bluefield Waterworks* and *Hope Natural Gas* . . . Finally, the Commission is confident that this ROE is appropriate given the company's forecasted capital expenditures and its required compliance with environmental regulations" (January 31, 2017 Order in Case No. U-18014, pp 65-66).

In Case No. U-17767 (DTE Electric's general rate case prior to U-18014), the Commission set DTE Electric's ROE at 10.3%, despite the ALJ recommending an ROE of 10.0%, in accordance with Staff's recommendation, explaining in part that "the Commission finds that an ROE of 10.3% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital . . . DTE Electric has an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements" (December 11, 2015 Order in Case No. U-17767, pp 54-55).

Most recently, the Commission again recognized that "customers do not necessarily benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner" (May 8, 2020 Order in Case No. U-20561, p 176, citing May 2, 2019 Order in Case No. U-20162, p 67).

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).

4. The Connection Between Equity and Capital Structure

A company's cost of equity and capital structure are inextricably intertwined because the use of debt increases the company's financial risk, and therefore increases the Company's cost of equity. A lower equity ratio component (and a correspondingly higher debt component) in the capital structure creates a higher level of risk for shareholders, and a corresponding need for a higher rate of return on equity. Dr. Villadsen's recommended ROE corresponds to a 50% equity ratio. If DTE Electric has less equity, however (and a corresponding increase in both debt leverage as well as financial risk), then DTE Electric's ROE must increase to compensate for the increased risk. A company with a lower equity share and higher financial leverage must earn a higher ROE in order to maintain the same overall return (Villadsen, 7T 1309, 1315-1318, 1356).

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).

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). It is also important to maintain DTE Electric's access to capital. Maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. A supportive allowed return on equity is important to ensure the utility's favorable access to credit markets. Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure.

D. Other Cost Rates

Tax law requires, and prior Commission orders have allowed, a return on Job Development Investment Tax Credits (JDITC) at the rate of return for permanent capital, so the associated returns for JDITC-Debt and JDITC-Equity reflect the corresponding permanent capital rates of 3.69% and 10.25%, respectively. Deferred income taxes are at zero cost (Villadsen, 7T 2811-2813; Exhibit A-14, Schedule D1, lines 6, 7, and 9).

E. Overall Rate of Return

The sum of the weighted cost of the above-described capital components results in a weighted, after-tax 5.56% overall rate of return (Villadsen, 7T 2809, 2811; Exhibit A-14, Schedule D1, line 10, column (g)). A 1.3496 revenue conversion factor is appropriate for the projected period (Villadsen, 7T 2810; Exhibit A-13, Schedule C2). The corresponding weighted pre-tax overall rate

of return is 6.98% (Exhibit A-14, Schedule D1, line 10, column (i)). DTE Electric supports the use of the 5.56% overall rate of return in the derivation of its revenue requirements and the use of the 6.98% pre-tax overall rate for the return on rate base.

VIII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY

DTE Electric's Total Electric Adjusted Net Operating Income (NOI) was \$1,071.7 million in the 2020 historical test year and was projected to be \$899.2 million in the projected test period (Uzenski, 7T 2705-2720; Exhibit A-13, Schedule C1, line 17). DTE Electric's operating income is projected to decrease due to increased O&M, depreciation and property taxes related to capital additions, and lower residential sales. The decrease in operating income is partially offset by higher revenues from new base rates in Case No. U-20561, effective May 2020, and lower income taxes (Uzenski, 7T 2719). Based on the NOI related adjustments discussed in Section I above, the Company agrees to adopt those adjustments and update its projected test year NOI to approximately \$912.8 million (Attachment A, page 3 of 4).

A. Sales Forecast

DTE Electric's forecasting methodology to determine future sales reflects widely-accepted industry standards for electricity forecasting, is continuously checked for accuracy, and has provided reasonable forecasts over time. For example, the 2019 total sales forecast compared to total weather-normalized service area sales reflects 98.2% accuracy. On average, for historical years 2016 through 2019, the absolute percent variance for the total sales forecast is 0.77% (Leuker, 7T 2617, 2637; Exhibit A-15, Schedule E5, page 1) DTE Electric also achieves better accuracy than peer utilities across the nation in forecasting various customer classes, total sales, and peak demand (Leuker, 7T 2638; Exhibit A-15, Schedule E5, page 2).

The forecast is developed separately for each of the major customer classifications (Residential, Small Commercial and Industrial (C&I), Large C&I, and Other). The sales in the Residential and Small C&I classes are forecast using separate Statistically Adjusted End-Use (SAE) models. The Large C&I class sales are forecast using a combination of regression equations and trend models for seven supersector markets (L 7-13). The models also used a “wedge” to estimate the COVID-19 impact⁷² in the history and forecast by customer class or market segment, which is used as an input variable along with economic, weather and other variables in the long-term forecasting models (Leuker, 7T 2623-2625).

For the projected test period, service area sales are projected to be 45,047 GWh, and bundled sales are projected to be 40,438 GWh (Leuker, 7T 2630; Exhibit A-15, Schedule E1, pages 1 through 3). Service area system output and annual peak demand are projected to be 48,427 GWh and 11,158 MW, respectively. Bundled system output and annual peak demand are projected to be 43,548 GWh and 10,341 MW, respectively (Leuker, 7T 2630; Exhibit A-15, Schedule E2, pages 1 and 2).

Mr. Leuker further explained that service area sales are expected to increase to 44,629 GWh in 2026. This represents a 0.2% average annual increase. Bundled sales are expected to decline to 40,061 GWh in 2026. This represents a -0.1% compound annual growth rate (CAGR). (7T 2632).⁷³

⁷² Mitigation strategies to reduce the spread of COVID-19 caused a shift in electricity consumption in DTE Electric’s service territory, with a general increase in Residential sales and decrease in C&I sales (Leuker, 7T 2623)

⁷³ DTE Electric's service area Residential Class sales are projected to decline 5.2% annually, on average, between 2020 and the projected period in this case, and increase by 0.6% annually, on average, between 2020 and 2026. DTE Electric’s service area Small C&I class sales are forecast to increase 6.9% annually, on average, between 2020 and the projected period, and to increase by 0.9% annually, on average, between 2020 through 2026. The sharp swings are due to the reversal of the effects of COVID-19 after 2020. (Leuker, 7T 2632-2633). DTE Electric’s service area Large C&I class sales are projected to increase by 6.7% annually, on average, from 2020 to the projected period, and to increase 0.6% annually, on average, from 2020 through 2026, due to underlying conditions in the local economy. DTE Electric's service area Other Class (which consists of street lighting and traffic signals) sales are projected to decline by 1.6%

AG witness Mr. Coppola found the C&I forecast to be reasonable, but proposed to increase the residential sales forecast by 796.4 GWh (from 15,114.0 GWh to 15,910 GWh), with a corresponding sales revenue increase of \$52,652,407 (8T 4850-4853). Mr. Leuker explained that witness Coppola's underlying analysis comparing 2020 and 2021 residential sales was flawed because it compared a full year of residential sales in 2021 to 2020, but COVID-19 related variances were present for less than ten months in 2020. To get an apples-to-apples comparison, it is appropriate to look at only the months in which COVID-19 related policies were present. A comparison of March through December in both 2020 and 2021 shows that residential use-per-customer is on a downward trajectory of -0.3%, which is consistent with the Company's expectation that as more people return to the office, residential use-per-customer will decrease (Leuker, 7T 2643-2644).

Mr. Coppola also took issue with the Company's use of Google Mobility data, asserting that it has no prior track record as an accurate predictor of sales, and that the Company did not provide any back testing to show its accuracy (8T 4851). Mr. Leuker responded by explaining that the COVID-19 pandemic rapidly changed the way people used electricity. The Company, as well as load forecasting groups across the country, expected that as more people stayed home, residential electricity consumption would increase and C&I consumption would decrease. The Company used Google Mobility data to quantify this expectation by measuring the magnitude of changed behaviors from COVID-19 related mitigation strategies. The mobility data was tested in the Company's sales models and proved to be statistically significant. Other industry experts such as Itron's Load

annually, on average, from 2020 through 2026, mainly due to the use of more efficient lighting (Leuker, 7T 2363). Choice sales are projected to increase to 4,567 GWh in 2026, which represents a 3.4% CAGR (Leuker, 7T 2632).

DTE Electric's temperature-normalized service area system peak demand declines from 11,246 MW in 2020 to 10,981 MW in 2026, representing a CAGR of -0.4%. DTE Electric's bundled peak demand declines to 10,169 MW in 2026, representing a CAGR of -0.7% (Leuker, 7T 2636-2737; Exhibit A-15, Schedule E2, page 2).

Forecasting Group (an industry-leading load forecasting consulting group) have also examined and recommended the use of mobility data as a reasonable methodology to address COVID-19 related variances in load forecast (Leuker, 7T 2645-2646). Mr. Coppola was also incorrect in asserting that the Company provided no back testing. Instead, the Company provided test results showing that the Company's residential model had 99.5% accuracy with the use of Google Mobility data, but would have significantly under-forecasted residential sales volumes for 2021 without that data (Leuker, 7T 2646-2647; Exhibit AG-1.37, page 5).

Mr. Coppola's alternative residential sales forecast was based on just using 2021's use-per-customer value and adjusting it only for Energy Waste Reduction (EWR), distributed generation, and electric vehicles (8T 4852). Mr. Leuker observed that Mr. Coppola has again changed his proposed forecasting method. Changing forecasting methodologies from case to case is unjustified, arbitrary, and lends itself to outcome-based data mining. In contrast, the Company has consistently used an end-use approach to forecast residential sales, with demonstrated accuracy (Leuker, 7T 2648; Exhibit A-15, Schedule E5). Mr. Coppola's proposed methodology is also extraordinarily uncommon for utility load forecasting. There are two predominant methods to forecast residential electricity sales. The Company uses the most widely used one. Mr. Coppola's simplistic methodology also improperly ignored trends in the underlying data. The Company's residential sales forecast is also validated by the Staff's analysis, which used more recent data than the Company used (which is an appropriate consideration) to arrive at a recommended 17 GWh (0.11%) increase, to 15,131 GWh (Leuker, 7T 2649-2650).

Turning to the Staff, in addition to the 17 GWh increase to residential sales, Staff also proposed a 140 GWh increase to the small C&I forecast, to a recommended 10,030 GWh, for a total recommended upward adjustment of 157 GWh (Ausum, 8T 5470 5; Exhibit S-20). Although

Staff's adjustments were not large, two modifications should be made to the underlying analysis to be more methodologically appropriate. First, Staff reduced both residential and small C&I sales by 2% to account for the Company's EWR program (Ausum, 8T 5470), but the 2% reduction does not apply across both customer classes. Instead, the correct reduction is 1.5% for residential and 2.2% for small C&I based on the Company's most recent EWR plan filing, Case No. U-20876. Second, Staff's methodology includes a projected trend to capture ongoing changes in electricity usage stemming from the Covid-19 pandemic (Ausum, 8T 5471-5472 6-7). This is generally appropriate; however, to avoid double counting the trends experienced in sales due to increased customer counts, Staff's analysis should be modified to reflect changes in use-per-customer rather than the change in total sales by customer class. This changes the "COVID load shift" for bundled residential from -2.01% to -2.64%, and for bundled small C&I from 1.87% to 1.13% (Leuker, 7T 2653-2655; Exhibit A36, Schedule AA3).

With these modifications, Staff's forecast is very similar to the Company's originally-filed forecast (see Exhibit A-36, Schedules AA1 and AA2). The bundled residential projection is 15,125 GWh (6 GWh lower than Staff's original projection), and the bundled small C&I projection is 9,853 GWh (177 GWh lower than Staff's original projection) (Leuker, 7T 2656-2657).

Thus, there is no sound basis to adopt Mr. Coppola's sales forecast methodology or resulting residential sales forecast. Also, Staff's bundled residential and small C&I forecasts (particularly as modified for appropriate methodology) are very similar to the Company's original forecasts, and Mr. Coppola found the Company's C&I forecast to be reasonable. Therefore, the ALJ should recommend, and the Commission should adopt Mr. Leuker's original sales projections.

B. Fuel and Purchased Power Revenue and Expense

DTE Electric proposes to maintain the current Power Supply Cost Recovery (PSCR) base of 31.26 mills per kilowatt-hour at the generation level, which the Commission established in its December 23, 2008 Opinion and Order in Case No. U-15244, and maintained in subsequent cases. The Company proposes to update the loss factor, however, which will result in a PSCR base of 33.55 mills per kilowatt-hour at the sales level as reflected on Exhibit A-13, Schedule C-4. Mr. Willis explained that the 7.31% loss factor is the average difference between annual system output and sales over the last five years (2016 through 2020) as shown on Exhibit A-13, Schedule C4.1, which is the method that the Commission approved in Case No. U-20561. The Company does not project any PSCR over or under-recovery in this case. The Company's proposed rates reflect the 33.55 base, and the Company used a zero PSCR factor to calculate revenues for the projected period (Willis, 6T 919-921).

In light of the above explanations, the Company's proposed PSCR loss factor recommendations should be adopted.

C. Operating and Maintenance (O&M) Expenses

DTE Electric had \$1,261.1 million of adjusted O&M in 2020, which was projected to increase to \$1,280.7 million in the projected test period (Exhibit A-13, Schedule C5, line 12, columns (f) and (l)). As discussed in Section I, the Company's projected O&M has been adjusted by a \$8.6 million reduction to Pension Expense, a \$4.2 million reduction to Tree Trim Surge O&M Savings, a \$3.0 million reduction to Merchant Fees, and a \$1.0 million reduction to Customer Service Representative costs, resulting in \$1,264.0 million (See Attachment A, page 3).

1. Inflation

Ms. Uzenski calculated inflation rates of 3.1% for 2021, 2.9% for 2022, and 2.42% for January 1 through October 31, 2023, as shown on Exhibit A-13, Schedule C5.15, line 15. These are composite rates using a 3.0% inflation rate for labor, and the consumer price index (CPI)-Urban for non-labor costs (Uzenski, 7T 2710). Mr. Cooper further explained that he conservatively estimated annual wage increases of 3.0% for 2021, 2022, and 2023, based largely on mandatory base pay increases and progression increases set forth in the Company's collective bargaining agreements with labor unions representing DTE Electric employees (7T 1813-1814).

The Commission previously declined to adopt a proposed composite inflation rate (January 31, 2017 Order in Case No. U-18014, p 72), and subsequently found that DTE Electric did not present sufficient evidence to induce the Commission to depart from its past decisions (April 18, 2018 Order in Case No. U-18255, p 38; May 2, 2019 Order in Case No. U-20162, p 74; and May 8, 2020 Order in Case No. U-20561, p 186). DTE Electric submits that the record reflects that the Company's labor costs are driven by collective bargaining agreements with unionized employees, as Mr. Cooper testified:

Based on existing Collective Bargaining Agreements, the Company is obligated to increase base pay rates by approximately 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions. [7T 1813]

DTE Electric also conducts reviews for employees who are not covered by collective bargaining agreements. Pursuant to these reviews, the Company implemented base pay adjustments in March 2021 that resulted in an overall pay increase of about 3.0%, just as it was in 2020 and every year since 2010. Employees also receive pay increases based on promotions (Cooper, 7T 1813, 1885).

There is no evidence that DTE Electric can avoid paying wage increases as set forth above, and any proposal that DTE Electric should do so neglects that DTE Electric cannot violate its Collective Bargaining Agreements, and the Commission has no authority to become involved in or dictate results of collective bargaining. Therefore, the Commission should approve DTE Electric's proposed composite inflation rate.

ABATE witness York asserted that the labor escalation should be based on "the same published independent economists' projections of future CPI growth that DTE used for non-labor cost escalation" (8T 3014). Mr. Cooper disagreed, explaining in part that over the last three years, the Company's average increase in employee wages has increased by 3.1%, during which the annual pay adjustment for each year was 3.0%. This actual experience demonstrates that the Company's projection of 3.0% is reasonable, and superior to ABATE's alternative proposal (Cooper, 7T 1885).

ABATE witness York further asserted that it is reasonable to expect the Company to continue to control or minimize O&M in a manner such that the total expense will change at a rate slower than the rate of inflation (8T 3017). The Company agrees that it has managed its O&M expenses well over the last decade, but the Company cannot continually offset wage growth (3.0% as discussed above) by managing non-labor O&M at levels much lower than the rate of inflation. Moreover, witness York acknowledged current CPI forecasts indicating that inflation "is expected to average 5.7% in 2022, and 3.0% in 2023" (York, 8T 3013). Thus, the Company will have even more difficulty managing inflationary pressures in the bridge period and test year than the Company predicted when it filed this case (Cooper, 7T 2389-2390).

Therefore, the Company's proposed composite inflation rates are fully justified and should be adopted.

2. Energy Supply (Exhibit A-13, Schedule C5, lines 1, 3 and 4; Schedules C5.1, C5.4 and C5.5)

DTE Electric's actual and forecast Energy Supply O&M expenses consist of three major categories: (1) Steam Power Generation, (2) Hydraulic Power Generation, and (3) Other Power Generation, as shown on Exhibit A-13, Schedules C5.1, C5.4, and C5.5 (Morren, 5T 714). Mr. Morren explained the major line items and adjustments (5T 717-23). Steam Power Generation adjusted O&M (*including* Fuel Supply and MERC fuel handling as described below) was \$247.8 million in 2020, and is projected to be \$232.2 million in the projected test year (Exhibit A-13, Schedule C5.1, page 1, line 19, columns (g) and (m)). Hydraulic Power Generation adjusted O&M was \$10.5 million in 2020, and is projected to be \$11.4 million in the projected test period year (Exhibit A-13, Schedule C5.4, line 17, columns (e) and (k)). Other Power Generation adjusted O&M was \$16.8 million in 2020, and is projected to be \$18.3 million in the projected test year (Exhibit A-13, Schedule C5.5, line 18, columns (e) and (k)). Based on these facts and as further detailed on the record, the Company's Energy Supply historical and projected O&M expenses are reasonable and prudent, and therefore should be recovered (Morren, 5T 724).

3. Fuel Supply and Midwest Energy Resources Company (MERC) (Exhibit A-13, Schedule C5, line 2; Schedule C5.2)

Mr. Milo supported DTE Electric's Fuel Supply and Midwest Energy Resources Company (MERC) O&M expense of \$7.8 million in 2020, and projected to be \$8.5 million in the 12-month projected test period ending October 31, 2023 (7T 2663, 2668-2669; Exhibit A-13, Schedule C5.2, line 16, columns (f) and (l)). Mr. Milo explained the nature of the O&M expenses for the projected test year, and that they were based on the adjusted historical 2020 expenses adjusted for inflation and those expenses should be determined to be reasonable and prudent (\$4.6 million for Fuel Supply and \$3.9 million for MERC, as shown on Exhibit A-13, Schedule C5.2, column (l), lines 7 and 15) (7T 2668-2669).

4. Nuclear Power (Exhibit A-13, Schedule C5, line 3; Schedule C5.3)

Mr. Davis supported Fermi 2's 2020 actual, as well as projected, nuclear O&M expenses through October 31, 2023 (7T 2535). Actual O&M expenses for 2020 were \$245.7 million (Davis, 7T 2558; Exhibit A-13, Schedule C5.3, page 1, line 24, column (c)). Three adjustments are necessary. First, column (d) reflects a \$27.8 million reduction because costs associated with site security (security and radiation protection services) were removed from base rates and recognized in the Nuclear Surcharge in Case No. U-14399. Second, column (e) reclassifies Program Evaluation Review Committee (PERC) project expenditures to make explicit that the \$11.6 million PERC base level and the \$12.3 million PERC Regulatory Asset amortization are not inflated in the projected adjustments. Third, column (f) reflects a \$25.0 million reduction to account for COVID-19 expenditures not projected to occur within the projected test period (Davis, 7T 2558-2560). Adjusted O&M expenses for 2020 were \$192.9 million (Exhibit A-13, Schedule C5.3, page 1, column (g), line 24), and were used to forecast projected O&M expenses through October 31, 2023. Mr. Davis explained various O&M expenses and adjustments, and testified that \$198.4 million of O&M will be required to support the safe and reliable operation of Fermi 2 in the projected period ending October 31, 2023, which is prudent and reasonable (Davis, 7T 2558-2559, 2573; Exhibit A-13, Schedule C5.3, page 1, line 24, column (n)).

The total PERC expense for the projected test period is forecasted at \$29.2 million (Exhibit A-13, Schedule C5.3, column (n), line 23). PERC expenses over or under \$15.0 million are deferred. The Company spent \$31.3 million on PERC projects in 2020, and expects to spend \$15.0 million in 2021, \$24.7 million in 2022, and \$17.0 in 2023 (Exhibit A-13, Schedule C5.16). Exhibit A-13, Schedule C5.17 shows the derivation of the PERC amortization (Davis, 7T 2566-2568).

AG Witness Coppola 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, reasoning 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).

Mr. Davis responded 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).

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

Distribution Operations’ O&M expenses are driven primarily by day-to-day trouble and storm restoration, tree-trim work, and other system maintenance requirements (Pfeuffer, 4T 391). The Company projects \$318.0 million of O&M expenses for the projected test period ending October 31, 2023 (Exhibit A-13, Schedule C5.6, p 1, line 26, column (I)). The forecast is based on actual 2020 O&M expenses, normalized and adjusted. Ms. Pfeuffer explained and justified significant components and adjustments underlying the projected O&M costs, as reflected on Exhibit A-13, Schedule C5.6, and supported the actual and projected O&M costs as reasonable and prudent (4T 391-395).

ii. 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 (Becker, 8T 5418). 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 (Pfeuffer, 4T 505).

iii. Tree Trimming

The Commission previously approved \$97.9 million of O&M funding for tree trimming, based on a May 1, 2020 through April 30, 2021 test year (May 8, 2020 Order in Case No. U-20561, p 191). The base O&M level has remained at \$97.9 million because the Company postponed filing a rate case in 2020 and 2021 (which would have included inflationary increases), leaving the surge program underfunded by \$3.8 million. Therefore, the Company now seeks to "catch up" to the 2023 base O&M, which is \$103.9 million.⁷⁴ The Company is requesting surge funding of \$67.0 million in 2023, and \$52.7 million in 2024; but is not presently requesting surge funding for 2025 (Hartwick, 7T 2318-2320; Exhibit A-13, Schedule C5.6.1). The Company is *targeting* to complete the surge program by the end of 2024, which is one year earlier than previously proposed in Case

⁷⁴ The Company also plans to spend \$2.0 million on the herbicide program in 2022, as outlined in previous rate cases. The herbicide program is based on industry best practices, and uses EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way. The targeted chemical treatment controls the tree species with the potential to grow into electrical wires, but does not affect grasses and shrubs. The herbicide treatment will reduce the cost of maintaining trimming in the right-of-way by reducing tree density, which will reduce overall trimming costs (Hartwick, 7T 2328-2329).

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 (Hartwick, 7T 2305-2306, 2354).⁷⁵

Recounting briefly for context, Michigan's 2013 ice storm left tens of thousands of customers without power and demonstrated that historic tree trimming practices were insufficient. The Commission recognized that trees are the primary cause of power outages, and that DTE Electric was fully spending its allocated funding for vegetation management to prevent such outages (May 2, 2014 Order in Case No. U-17542, p 16; December 4, 2014 Order in Case No. U-17542, pp 4-5). Therefore, DTE Electric began investing in a new Enhanced Vegetation Management Program (EVMP, now re-named the Enhanced Tree Trimming Program or ETTP), which essentially removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved the ETTP in Case No. U-17767, and increased funding to clear more miles of lines in Case No. U-18014. In Case No. U-18255, the Commission again approved increased ETTP funding, emphasizing the importance of expenditures to improve the distribution system's safety and reliability (April 18, 2018 Order in Case No. U-18255, pp 43-44). In Case No. U-20162, the Commission again recognized the importance of tree trimming, and approved DTE Electric's seven-year Surge proposal, in part (May 2, 2019 Order in Case No. U-20162, pp 79-80). In Case No. U-20561, the Commission "reiterate[d] its desire for a safe and reliable electric system" and "approve[d] the \$58.2 million requested surge funding for 2022" (May 8, 2020 Order in Case No. U-20561, pp 208-209).

Against this background, Company witness Hartwick testified that in 2020, DTE Electric (1) trimmed 5,589 line-miles on 814 circuits (exceeding its plan of 5,500 miles); (2) completed

⁷⁵ Ms. Hartwick discussed resources needed to meet the accelerated goal of completing the Surge by the end of 2024, including the number of tree trimmers that are needed, the risks to maintaining and growing the current level of tree trimmers, and the Company's efforts to grow the local work force (7T 2323-2328).

25,557 tree trim comparable units (exceeding a target of 25,319); and (3) spent \$151.1 million on line clearance maintenance costs. (Hartwick, 7T 2282).

DTE Electric uses “comparable units” to measure tree-trim work performed more accurately than just miles trimmed. Work volume is defined by tree density. The Company’s circuits range from less than 10 trees per mile to more than 1,000 trees per mile. Work complexity measures many factors that influence the cost to perform work in a given area, including back lot work, security, off-cycle work and customer outreach (Hartwick, 7T 2283-2285).

Ms. Hartwick explained that the Company completed 101% of its comparable unit work target in 2020 and planned to trim 6,156 miles and 23,524 units in 2021 (567 more miles than were trimmed in 2020). (7T 2287-2288). The 2021 miles are lower than the Company’s estimate in Case No. U-20561 (6,455 miles) because the model in that case was based on an average mile (average density and average complexity). The Company prioritizes circuits for trimming based on reliability impacts and wire down reductions. Frequent outage circuits generally have a high unit density compared to the Company’s system average. Completing high density circuits at the start of the surge results in fewer miles trimmed, but the same amount of work completed. Weather also had significant impacts in 2021, and the Company focused resources on the communities and circuits most impacted by the summer storms (Hartwick, 7T 2288-2289).

The ETTP is a well-designed program with proven success and continuing importance. Circuits trimmed as part of the ETTP have a 76.1% reduction in tree-related interruptions in the year after trimming, which is dramatically better than the 13% reduction produced by the historical practice of just trimming a “clearance circle” around conductors. ETTP-trimmed circuits similarly showed reductions of 62.9% in customer interruptions, 57.3% in the number of customer minutes

of interruption, and 32.2% in wire-down events in the year following trimming, compared to non-ETTP circuits (Hartwick, 7T 2291-2294).

The Company made several significant improvements to its tree-trimming program in the last twenty-four months, including: (1) long-term contracts with tree-trim vendors, (2) specialty equipment, (3) improved price accuracy by utilizing its arborist employees to set up a specialized estimating team to price out circuits before contractor bids are evaluated, and (4) improved timeline for contract negotiations to be completed in the fall (Hartwick, 7T 2296-2300). The Company is also working on several initiatives to further improve its tree-trim program (Hartwick, 7T 2300-2301).

The surge program needs to continue because, as discussed in the Company's Grid Distribution Plan in Case No. U-20147, tree interference is the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power. No other program in the Company's portfolio of distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's distribution system (Hartwick, 7T 2302-2303).

The tree trimming program should be funded to maintain a trimming cycle where circuits are re-trimmed before the trimmed trees grow back into the Company's wires and become hazards. The Company remains firmly committed to achieving a five-year trimming cycle for distribution circuits (three years for sub-transmission circuits because of the high customer impact of trouble events on these circuits). Assuming an average mile, a five-year cycle requires trimming approximately 6,538 miles per year. The five-year cycle was determined because (1) trees near the Company's distribution equipment grow approximately 10 feet in five years, and (2) the five-year cycle provides a reasonable and acceptable level of tree-to-conductor contact (the likelihood of

any portion of a tree touching a conductor) comparable to the industry average standard of 10% to 15%. The Company's targeted five-year cycle is also comparable to the industry average of 4.9 years (Hartwick, 7T 2303-2308).

Reducing the tree-trimming cycle to five years will provide multiple customer benefits and savings including: (1) fewer wire down events, resulting in improved safety; (2) fewer outage and non-outage events, leading to improved reliability and a positive impact on reactive O&M and capital costs, as well as the re-allocation of resources to other necessary work across the distribution system; (3) lower customer complaints from tree-related events; (4) lower future tree-trimming costs; and (5) lower customer costs as tree-related outages are reduced (Hartwick, 7T 2308-2309).

Ms. Hartwick explained:

The tree trimming program is the most impactful and important program in the Company's long-term investment strategy. The program has shown that it significantly decreases system risk (specifically reduced wire downs), increases reliability (fewer and shorter outages), and will decrease reactive trouble costs. The tree trimming program as proposed is required to provide safe, reliable and affordable electricity to the Company's customers. Without continuing the Surge investment, the distribution system will continue to degrade, resulting in higher costs and lower reliability (7T 2331).

Ms. Hartwick also testified that her opinion is based on analysis of past expenses, and the projected requirements for labor and materials to conduct the necessary tree trimming (7T 2331). A net present value (NPV) analysis further indicates that continued execution of the surge is \$71.2 million favorable to customers as compared to just the baseline O&M tree trimming without the surge funding (Hartwick, 7T 2309, 2320-2321; Exhibit A-22 Revised, Schedule L1, pages 3 and 6). This \$71.2 million benefit is based just on the forecasted reduction in revenue requirement through 2042, without even considering the value of improved reliability to customers (Hartwick, 7T 2309).

AG witness Coppola proposed the removal of \$5.7 million in cost savings from the Company's forecasted O&M expense due to savings from the surge program (8T 4858). The Company agrees, in part, but the correct amount is \$4.2 million. Ms. Hartwick explained that the \$5.7 million includes three items. Savings from two items (Tree Trim Storm (\$2.4 million) and Dist. Ops Storm & Trouble (\$1.8 million)) should be considered as reductions to the Company's O&M expense but were inadvertently omitted from the O&M calculation in Exhibit A-13, Schedule C5.6. In contrast, savings from the third item (Tree Trim Reactive) were included in Exhibit A-22, line 4, so those savings have already been accounted for in the proposed O&M expenses (Hartwick, 7T 2334).

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 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).⁷⁶ This treatment was continued in Case No. U-20561.

⁷⁶ 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.

In contrast to this treatment, in the securitization 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).⁷⁷ Exhibit A-11, Schedule A1.1 identifies 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 (Nichols, 8T 5033-5035). AG witness Coppola proposed a \$5,626,000 reduction by using a short-term debt rate of 1.74% (8T 4883-4885). Both Staff and the AG essentially reasoned that 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 conducted 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).

⁷⁷ 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).

In compliance with the Commission's reporting requirements (May 2, 2019 Order in Case No. U-20162, p 81; May 8, 2020 Order in Case No. U-20561, p 208), the Company will provide annual reports until the Surge program is complete, and a Tree Trimming Effectiveness Report in 2022 (Hartwick, 7T 2329-2330).

Therefore, the Commission should adopt the Company's tree-trimming requests and reject all contrary and additional proposals.

iv. 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 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 disallowance because the Company did not spend the full amount in 2021 (Wang, 8T 5173). The Company disagrees for two reasons. First, Staff referenced the Company's projected O&M spend, in which the Company used its historical 2020 YE spend. The Company projected no additional O&M spend and only seeks adjustments as a result of inflation though the bridge period and projected test year. Second, Staff referenced O&M spend in 2021 to

establish a ratio of actual spend compared to approved spend. The Company's 2021 O&M actuals were far in excess of the amount the Company seeks to recover in this case. Therefore, the Company's O&M request should be fully approved (Bellini, 7T 1775-1776).

Mr. Bellini also responded to MI-MAUI witness Bunch's criticisms about streetlight outage performance, providing additional context about the Company proactively identifying additional outages (with corresponding additional short-term costs) through its night patrol program, which is a great step toward reducing outages and increasing system reliability (Bellini, 7T 1738, 1749-1750, 1755). It is also inappropriate to use Company-owned Ann Arbor streetlight data to assess outage frequency for all Company-owned lights because this is not a representative sample (5,300 lights, or 3.2% of approximately 167,000 total Company-owned municipal lights). There also tends to be a higher likelihood of outages as the volume of construction projects increases. Specific to Ann Arbor, there have been several suspected third-party strikes on the Company's underground cable, which resulted in a multitude of outages over the past several years (Bellini, 7T 1751-1752).

With regard to restoration time, it is also important to keep in mind that there are (1) events where DTE crews are impeded from performing a repair due to a need to wait for a permit, Miss Dig, etc., as well as (2) events that require special order material (SOM) for which the city, not DTE, is responsible for purchasing and maintaining the SOM in order to complete restoration work. When unimpeded, the Company has been able to address outage events in under five days, except in 2014 and 2021, which had significantly higher and more severe storm seasons that required streetlight crews to be redirected to perform storm restoration work. The type of repair must also be considered. For example, to repair underground damage, Ann Arbor requires a significant amount of detail denoted on Company engineered permit drawings. This level of detail is not required by other municipalities before a permit is granted to allow restoration work to begin. The

level of detail to ensure compliance with Ann Arbor's permitting requirements often takes several weeks to compile (Bellini, 7T 1752-1753).

Mr. Bellini provided additional details regarding third parties striking underground cable in response to MI-MAUI witness Hess' criticism about outages (7T 1771-1772), and Ann Arbor's time-consuming permitting requirements in response to witness Hess' criticisms about restoration times (7T 1772-1773; Exhibit A-34, Schedule Y5). Also, all underground capital cable replacements are being installed in conduit, which will help protect against (although not completely eliminate) the potential for Company cable to be cut or severed (Bellini, 7T 1773).

MI-MAUI witness Bunch's further suggestions regarding outage-related credits (8T 3480) similarly neglected the root causes of lighting failures and impediments to certain repairs, as well as the Company's actual performance for standard and follow-up events, and launch of its night patrol program to proactively identify more outages and increase reliability (Bellini, 7T 1763-1766; Exhibit A-12, Schedule O-1).

Mr. Bunch's proposal that the Company provide annual reliability reports to each customer (8T 3481) is unnecessary for three reasons. First, it is based on the premise that all outages result from a failure of Company equipment and that the Company's repairs take too long, which is inaccurate as discussed above. Second, it would be unnecessarily burdensome and time consuming to create such a report for each customer. Third, the Company is transparent regarding its system-wide Community Lighting performance metrics (Bellini, 7T 1766-1767; Exhibit A-25, Schedules O-1 and O-2).

MI-MAUI witness Bunch suggested that the Company should stop group relamping to accelerate the conversion to LEDs (8T 3458). The Company disagrees for three reasons. First, the Company's study indicated that re-lamping reduced outages, and the current program cadence is

appropriately based on manufacturer specifications (Bellini, 7T 1758-1759; Exhibit A-34, Schedule Y2). Second, HPS luminaires are a Commission-approved product offering that municipal customers can choose, and the Company has an obligation to service Commission-approved offerings. MI-MAUI is essentially asking the Commission to act contrary to the existing tariff and to the detriment of communities that have chosen to use HPS luminaires. Third, if the Company were to discontinue group re-lamping, then we could expect an increase in outage events, which would be counterproductive in maintaining reliability (Bellini, 7T 1759-1760).

MI-MAUI witness Bunch suggested that the Company is spending too much on LEDs by departing from manufacturer-recommended specifications (8T 3467). To the contrary, the Company uses the GCL J-Series model for conversions, which provides flexibility with a wide range of wattages and lumen output (10 total) to accommodate the low to high lumen output of incumbent 400W HPS cobra head luminaires, and with the ultimate purpose of providing adequate streetlighting for the circumstances. For example, the Company uses a GCL J-Series model with higher lumen output to replace HPS luminaires along major thoroughfares (long stretches of roadway with multiple lanes of traffic). To provide value for customers, the Company's standard practice is place higher-lumen-output luminaires on taller streetlight poles that are spaced farther apart, which lowers costs by using fewer poles and luminaires to achieve the desired and ANSI/IES compliant light levels (Bellini, 7T 1760-1762; Exhibit A-34, Schedule Y3).

MI-MAUI witness Bunch suggested that the Company is needlessly washing lamps on an accelerated basis and out of step with IES recommended practices (8T 3472). The Company disagrees because 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).

6. 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).⁷⁸ These O&M expenses (including rate case adjustments) were \$110.7 million for the 2020 historical test period, and were expected to increase to \$133.6 million for the projected year (Sparks, 7T 1616, 1624, 1636-1639; Exhibit A-13, Schedule C5.7), but the Company now agrees to a \$0.95 million O&M reduction as discussed below.

Mr. Sparks discussed the Customer Service organization's response to the COVID-19 pandemic (7T 1621-1623), work activities performed in 2020 (7T 1624-1636), and testified that the projected O&M increase is based on continuing those activities, with inflation of \$8.2 million for 2021 through October of 2023,⁷⁹ a known and measurable adjustment for fees paid to process credit card payments (merchant fees) of \$6.8 million, and other adjustments including Customer Records and Collection Expenses of \$7.9 million (7T 1636).

⁷⁸ 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).

⁷⁹ The rate of inflation is 3.1% for 2021, 2.9% for 2022, and 2.42% for the first 10 months of 2023 (Uzenski, 7T 2710; Exhibit A-13, Schedule C5.15, line 15).

i. Customer Service Representatives (CSRs)

Mr. Sparks explained that the \$7.9 million of Customer Records and Collections Expenses is driven in part by the need for 120 additional customer service representatives (CSRs) and associated expenses 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 Time of Use (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).

AG witness Coppola proposed a \$9.7 million reduction in O&M expense, indicating that it relates to the additional 120 CSRs (8T 4860-4861). Mr. Sparks clarified that only \$5.6 million relates to the incremental 120 CSRs. The \$9.7 million 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 time with customers as they need and deserve, 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 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 regarding requirements for agency resources (Sparks, 7T 1645-1646).

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).

ii. Merchant Fees

Mr. Burns explained that the projected test year expense for merchant fees is \$20.5 million based on a three-year compound average growth rate (CAGR) from 2018 through 2020 (7T 2495-2496; Exhibit A-13, Schedule C.5.7.1, page 1, column (g), line 5).

Mr. Maroun further explained that, consistent with Case No. U-20561, residential merchant fees are directly assigned to the residential class, and commercial merchant fees are directly assigned to the commercial secondary class in the Company's unbundled Cost of Service Study (UCOS). This methodology results in no cross-subsidization across cost-of-service rate classes related to merchant fees and satisfies Staff's indicated concern in this area (Maroun, 6T 1041. See also Burns, 7T 2495).

Staff witness Ms. McMillan-Sepkoski proposed a \$3 million disallowance based on 1) a three -year average (including 2021 actuals) percentage increase in credit/debit card use based on third party vendor invoicing and 2) a slightly more conservative and accurate projection for the test year (8T 5265, Exhibit S-8.4).

AG witness Mr. Coppola proposed an \$8.2 million reduction to residential merchant fee expense of \$19.1 million to \$10.9 million (8T 4866). The AG's proposal should be rejected because it only accounts for annual growth from 2020 to 2021. DTE Electric used a three-year historical growth rate to forecast the projected test years to avoid anomalies from any specific year (such as 2020, which was impacted by the pandemic). (Burns, 7T 2528).

Mr. Coppola's reasoning is also flawed. He stated: "As more and more customers pay their bill with a credit card, there are fewer customers left who will make use of credit cards to pay their gas bills. This is basic logic. The 2021 actual data supports this conclusion" (8T 4864-4865). Mr. Coppola inaccurately assumed that merchant fees are directly related to the number of customers paying their bill with a credit or debit card. Instead, merchant fees are driven primarily by the volume of payment transactions and the rate of fees (per transaction) charged by the various credit and debit card companies and banking institutions. Therefore, the merchant fee forecast is based on the growth in actual transaction fees assessed to DTE Electric annually (Burns, 7T 2527-2528).

Staff's proposed merchant fees expense amount of \$17.5 million utilized the three-year average with updated actuals which results in a slightly more conservative and accurate projection for the test year which the Company does not oppose and should be adopted by the Commission.

7. Uncollectible Accounts Expense (Exhibit A-13, Schedule C5, line 8; Schedule C5.8)

Uncollectible expense is recorded in the income statement to reflect the portion of accounts receivable (AR) that is considered uncollectible. 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)).⁸⁰ DTE Electric excluded 2018 because uncollectible expense was abnormally high due to system issues and delayed collections, resulting from the Customer 360 (C360) billing system implementation. The three-year average from 2018-2020 is \$71 million (Johnson, 5T 822).

DTE Electric has worked proactively to reduce uncollectible expense and is continuing its initiatives to prevent uncollectible expense including efforts in anticipation of a reduction in COVID-19 relief (Johnson, 5T 824-825).

Staff proposed a \$9,560,000 downward adjustment (from \$59,560,000 to \$50,013,000) (Rueckert, 8T 5460; Exhibit S-18). AG witness Coppola proposed a \$9.4 million reduction to \$50.3 million (8T 4862-4864). Both 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

⁸⁰ The costs associated with uncollectible expense are assigned based on net write-offs (Maroun, 6T 1041).

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). Two corrections should also be made: (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. These corrections would result in an uncollectible expense of \$55,398,915 million (Exhibit A-37, Schedule BB1). If the Commission agrees with Staff's methodology, then the Company does not dispute the \$4.174 million reduction from its original projection of \$59.573 million based on the inclusion of 2021 actuals and the required corrections to Staff's analysis (Johnson, 5T 829-830).

8. Regulated Marketing (Exhibit A-13, Schedule C5, line 9; Schedule C5.9)

Regulated Marketing had \$15.6 million of O&M expense for the 2020 historical test year (Exhibit A-13, Schedule C5.9, column (e), line 18). This expense included Major Account Services,

Electric Marketing, Economic Development, Demand Response (DR) costs, and amortization of Charging Forward and ACPP regulatory assets (Burns, 7T 2499).

DTE Electric seeks to recover \$24.0 million in the projected test year (Exhibit A-13, Schedule C5.9, column (k), line 18). Mr. Burns outlined the known and measurable changes to the historical 2020 O&M expense, and supported the resulting projected expense as a reasonable and prudent level necessary to support the new programs that the Company proposes in this case, as well as to maintain the existing level of customer support to commercial and industrial major account customers, support the Company's economic development activities, and educate all customers regarding regulated Company offerings (Burns, 7T 2500-2501).

9. 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 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).

i. 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). Mr. Crozier responded by explaining 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 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).

Mr. Morren supported the Company's \$0.5 million request for membership in the Low Carbon Resource Initiative (LCRI), which is a five-year joint effort between the Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI) aimed at accelerating the development and demonstration of low and zero-carbon energy technologies for large-scale deployment. The Company is joining the LCRI because it recognizes the need for research and development to support viable, affordable, and sustainable solutions as it moves toward reaching a zero-carbon power generation fleet by 2050. By joining the LCRI, the Company will leverage resources with over 45 other companies worldwide, including Consumers Energy and other utility peers, to evaluate a wide range of pathways to economy-wide decarbonization. Customers will benefit because participation in the LCRI will give the Company immediate and direct access to LCRI projects, which will allow the Company to best leverage the successes and learnings of the overall effort for the benefit of customers (Morren, 5T 721-722).

10. 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).

i. Pension

DTE Electric developed its projected pension expense based on the accounting requirements of U.S. GAAP Accounting Standard Codification (ASC) 715-730 (ASC 715-730), under which there are four components of pension costs, as described below:

Service Costs: This represents the pension benefits earned by active employees during the current period on a present value basis. They are based on actuarial assumptions including current and projected salaries, expected employee turnover, and life expectancy.

Interest Costs: The interest cost recognized in the current period is the increase in the Projected Benefit Obligation (PBO) due to the passage of time. The PBO is the actuarial present value of benefits attributable to the pension benefit formula discounted back to current dollars at discount rates of 2.57% for the historical period, and 2.57% for the projected period. Measuring the PBO as a present value at the beginning of the period requires the accrual of an interest cost for the current period at a rate equal to the discount rate. The discount rate for the historical period is based on the interest rate environment at the end of 2019, the prior fiscal year end, and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated Aa or higher, provided by DTE Electric's independent actuarial firm, Aon. The 2.57% discount rate for the projected period reflects an expectation that high-quality corporate bond interest rates at the end of 2022 will remain essentially unchanged from levels prevailing in December 2020.

Expected Return on Assets: This is an estimate of the expected investment return on assets invested in the pension trusts for the current period. While actual year-to-year investment returns can vary significantly, the expected return is determined based on long-term financial market expectations in order to avoid large swings in pension costs based on short-term investment performance. DTE Electric's estimated annual rate of return was 7.1% for the 2020 historical period, and is reduced to 7.0% in 2021, 6.8% in 2022, and 6.7% in 2023.

Unrecognized Gains and Losses: The cost of Unrecognized Gains and Losses reflects the amortization of the accumulated changes in the PBO or plan's assets resulting from actual experience in a given year that is different from that assumed in the actuarial assumptions for the year. Most notably, since discount rates and return on asset assumptions are based on either point-in-time measurements or estimates, differences can arise due to changes in the interest rate environment between year-end measurements, and when actual asset returns differ from long-range expectations.

Prior Service Costs: The amortization of Prior Service Costs relates to pension plan design changes that will affect future benefit payments (Cooper, 7T 1784-1786).

DTE Electric's annual pension costs are expected to decrease from \$92.9 million in the historical test period to \$13.5 million in the projected period, or \$9.2 million inclusive of the effects of costs capitalized and transferred, as reflected in the Company's initial filing (Cooper, 7T 1787-1788; Exhibit A-13, Schedule C5.12.1).

AG witness Coppola proposed that the Company's projected pension expense be reduced \$17,442,000, from \$9.145 million to -\$8.297 million (8T 4873). The Company disagrees because there are significant flaws in the AG's proposal. For example, it is based on sensitivities prepared

by the Company in response to the AG's discovery requests, which do not reflect the same analytical rigor that would be used in a formal projection of pension costs by the Company's independent actuaries. The AG's reliance on pension cost projections not prepared by the Company's actuaries is inconsistent with the Commission's requirement that pension cost projections used in determining revenue requirements be based on independent actuaries, which "ensures that the expense has been reviewed and vetted by the actuary and is the most accurate projection available" (Case No. U-17990, Order dated February 28, 2017, p 97).⁸¹ The sensitivities also included, at the AG's request, an assumption that the Expected Return on Assets (ERoA) would remain at 7.0% for the entire projected period, which is an unreasonable assumption (Cooper, 7T 1876-1883). The AG's support for the 7.0% ERoA is premised on the actual return on pension assets over the last 12 years, the opinion that there exists significant discretion in determining the ERoA and the claim that the Company has not shifted its pension assets into more conservative asset classes. On rebuttal, Mr. Cooper demonstrated the unreasonableness of the 7.0% ERoA assumption by disputing the reliability of only 12 years of actual pension asset returns. Moreover, the use of only 12 years of actual pension asset returns fails to recognize the substantial shift in pension assets during that period. Specifically, the proportion of assets invested in fixed income assets has increased from only 25% in 2010 to 48% in 2021 with a further increase in the target fixed income allocation to 57% in 2022 (Cooper, Rebuttal Table 5, 7T 1879). This shift in the mix of pension assets reflects the Company's investment policy of reducing the risk of pension funded status as the total funding of the pension liabilities increases, which has increased from 78% in 2010 to 97% in 2021 (Cooper Rebuttal Table 6, 7T 1880). Finally, the AG's proposal to include the

⁸¹ Mr. Cooper presented an updated pension cost projection prepared by Aon, the Company's independent actuary that reflected pension expense for the projected test year of \$0.6 million, which reflects actual asset returns in 2021 and a 2.91% discount rate and represents the most up to date and reliable pension cost estimate (7T 1882, Exhibit A-35, Schedule Z6).

7.0% ERoA assumption is inconsistent with the ERoA assumptions used by the 100 largest pension plans, which has declined from 8.21% in 2010 to 6.33% in 2021 (Cooper Rebuttal Table 7, 7T 1883). Accordingly, the AG's advocacy of the 7.0% ERoA is unreasonable because it fails to recognize the risk reduction investment strategy of the Company and is dramatically higher than the ERoA used by other pension plan sponsors.

Company accounting expert Uzenski further explained that the AG's proposal to include a negative pension expense of \$8.297 million is also inappropriate because if pension expense is included in the revenue requirement as a negative amount, then this would result in a reduction in cash revenue without a corresponding reduction in cash expenditures. The required funding of the pension plan is made independently of the amounts recognized in expense, and cash cannot be refunded from the pension plan assets if book expense is negative (Uzenski, 7T 2779).

The AG's proposal is also unnecessary because the Company proposes a pension deferral mechanism that would eliminate the uncertainty of future pension expense, which is highly dependent on assumptions of market returns and long-term interest rates (Cooper, 7T 1883-1884).⁸² To address potential volatility and the possibility that future pension costs could be negative, the Company proposes a deferral mechanism for pension expense similar to the mechanism in place for the Company's OPEB expense (discussed below), and consistent with the Commission approved deferral of pension expense for DTE Gas (Case No. U-20940, Order dated December 9,

⁸² Mr. Cooper performed analyses showing that there is potential for extreme volatility in the Company's pension costs due to changes in actual results and updated assumptions, and that the Company could, under certain circumstances, incur negative pension costs (as the AG suggests based on certain assumptions). The first scenario (assuming a 12.0% actual return on pension assets in 2021 rather than the 7.0% in the base forecast) results in the Company's pension costs for the projected test year decreasing to negative \$7.9 million. The second scenario (further assuming that the discount rate in December 2021 is 100 basis points higher than the 2.57% assumed in the base forecast) results in the Company's pension costs for the projected test period decreasing to negative \$33.7 million. A third scenario based on a reduction in the assumed return on assets as a result of the assumption that the pension liabilities would be fully funded reduces the negative pension cost to \$3.6 million (Cooper, 7T 1789, Exhibit A-13, Schedule C5.12.2).

2021, p.154). Under the Company's proposal actual pension expense would be deferred to a regulatory asset if positive, or a regulatory liability if negative, with the net deferred amount carried on the balance sheet for review in a future rate case. If the Commission adopts the Company's proposal, then the \$0.6 million pension expense for the projected test year would be eliminated (\$0). Staff also expressed its agreement with the Company's proposal in a discovery response, Exhibit A-43, Schedule HH3 (Cooper, 7T 1790; Uzenski, 7T 2712, 2779).

Therefore, the Commission should either adopt the Company's updated projected pension expense of \$0.6 million (Exhibit A-35, Schedule Z6), or adopt the Company's proposed pension deferral mechanism.

ii. Other Post-Employment Benefit (OPEB) Expenses

DTE Electric's OPEB costs are related to the provision of retiree medical, dental, prescription drug, and life insurance benefits. DTE Electric's projected OPEB expenses are determined pursuant to U.S. GAAP Accounting Standard Codification 715-760 (ASC 715-760), which parallels ASC 715-730, reflecting the cost of benefits earned by employees during the year, the interest cost on the discounted Accumulated Postretirement Benefit Obligation (APBO), the expected return on assets invested to meet the future liabilities, and the amortizations related to deferred gains and losses as well as prior service costs (7T 1791-1792).

DTE Electric's OPEB costs are projected to decrease from a negative \$27.0 million in the historical test period to a negative \$35.0 million in the projected period, or negative \$21.5 million inclusive of the effects of costs capitalized and transferred (Cooper, 7T 1792-1794; Exhibit A-13, Schedule C5.12.3).

The Commission approved the Company proposal to defer negative OPEB expense to a regulatory liability (December 11, 2015 Order in Case No. U-17767, p 69), and to continue that

deferral (January 31, 2017 Order in Case No. U-18014, pp 94-95; April 18, 2018 Order in Case No. U-18255, p 34, n 8; May 2, 2019 Order in Case No. U-20162, p 91; May 8, 2020 Order in Case No. U-20561, p 209). The Company proposes the continued deferral of the negative net OPEB expense consistent with prior treatment. If net OPEB expense becomes positive in the future, then the expense will be charged against the regulatory liability. Therefore, the negative OPEB expense is not included in the Company's proposed revenue requirement, and there is no obligation for the Company to fund its OPEB liability (Cooper, 7T 1794; Uzenski, 7T 2711-2712).

iii. 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 C5.11.1.⁸³ WTW's trend factors are adjusted by 0.5% to reflect the expected savings from the Company's Wellness program,

⁸³WTW 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).

(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 he 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 \$48.5 million after allocating a portion to capital expenditures (8T 4867-4869).

The AG's proposal should be 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 of \$55.5 million 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 proposes 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 uses 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 mischaracterizes 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). To the contrary, the 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).

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 (which would be improper), 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).

In addition to understating the proper starting point in the projection of Active Healthcare expense, Mr. Coppola also understates 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.

iv. Other Employee Benefit Costs

The Company's Other Employee Benefits are projected to be \$9.872 million (Exhibit A-13, Schedule C5.11 Revised, line 27). These costs include a variety of other benefits including Accrued Vacation, Supplemental Severance Plan, Wellness Plan, Long-Term Disability expense, costs associated with the Affordable Care Act (ACA), General Benefits expenses, as well as the Supplemental Savings Plan and Deferred Compensation Plan (Cooper, 7T 1807-1811).

11. Employee Compensation

DTE Electric's overall employee compensation philosophy is to provide pay programs that (1) attract, retain, and motivate employees; (2) ensure that pay is externally competitive; and (3)

differentiate total rewards based on both organizational unit and individual contributions and results (Cooper, 7T 1814). The Company’s incentive compensation programs for both its executive and non-executive employees 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).

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 both operating and financial metrics. The components of these expenses are reflected in the table below, as differentiated for the portion of such expenses based on operating versus financial performance measures (Cooper, 7T 1832-1833).⁸⁴

	<u>LTIP</u>	<u>AIP</u>	<u>REP</u>	<u>Total</u>
Financial	\$22.0	\$5.6	\$13.9	\$41.5
Operating	\$1.0	\$6.0	\$15.2	\$22.3
Total	\$23.0	\$11.6	\$29.1	\$63.8

⁸⁴ Pursuant to the May 8, 2020 Order in Case No. 20561, incentives related to capital measures that were capitalized during 2018 and 2019 were written off to expense, and the cost will not be recovered from customers. Capital expenditures from 2020 forward do not include incentive costs related to financial metrics (Uzenski, 7T 2741).

The operating measures reflected in the short-term incentive plans relate to Customer Satisfaction, Safety and Engagement and Operating Excellence, as appropriately customized for the specific business units. Customer Satisfaction measures are intended to focus employees on improving the experience that customers have in their interactions with the Company. Employee Engagement measures encompass employee engagement as measured by the Gallup survey and employee safety. Operating Excellence includes measures related to fossil power plant reliability, reducing the length of service interruptions, as well as additional specific measures related to the nuclear generation business unit (Cooper, 7T 1825-1829).

Staff proposed to exclude \$42,537,000, representing incentive compensation expense related to financial measures, indicating that it understood recent decisions by the Commission to have established a “policy” of excluding financial performance measures from the revenue requirement (McMillan-Sepkoski, 8T 5263-5264). To the contrary, 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).⁸⁵ Thus, financial measures have not been, and cannot lawfully be, categorically disallowed as Staff suggests.⁸⁶ This proposed disallowance, along with similar proposals including ABATE’s proposed \$41.473 million disallowance related to financial measures (York, 8T 3019), also ignores the benefits resulting from a financially healthy company and the

⁸⁵ 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).

⁸⁶ 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.

importance of offering total compensation that is sufficient to attract and retain employees, as further discussed below (Cooper, 7T 1865).

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. This proposed disallowance is improper even under Staff's reasoning because these operating measures (the INPO Index and Nuclear On-Line Capability Factor) are unrelated to financial results, and therefore meet the Commission's traditional practice of requiring quantified customer benefits through improved reliability and lower costs (Cooper, 7T 1848-1850).

AG witness Mr. Coppola proposed the complete elimination of incentive compensation expense related to financial measures (\$41.473 million), plus 40% of incentive compensation expense related to operating measures (\$8.490 million), which totals \$49.963 million; however, he proposed a \$51.028 million disallowance (8T 4880-4881). The difference is \$1.065 million, which equals the LTIP expense related to Nuclear Generation operating measures. Mr. Coppola offered no basis to disallow this expense, so the Company assumes it was just inadvertently included in his total proposed disallowance (Cooper, 7T 1854-1855).

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). The presumption that shareholders benefit exclusively from the Company's achievement of its financial measures also ignores the value to customers of avoided interest costs resulting from the Company maintaining its existing credit ratings, which represents a total customer benefit of \$18.5 million (Cooper, 7T 1852, 1855; Exhibit A-21, Schedule K6).

Incentive compensation programs are an increasingly prevalent practice among the vast majority of energy companies.⁸⁷ 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. 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 1817-1818, 1852; Exhibit A-21, Schedule K1).⁸⁸ Moreover, without the Company's short-term incentive

⁸⁷ 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).

⁸⁸ 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).

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).

Staff further proposed the disallowance of \$5,587,000 of Restricted Stock expense, reasoning that it relates to the achievement of financial performance measures (McMillan-Sepkoski, 8T 5264). Mr. Cooper explained that the LTIP has two components (Performance Shares and Restricted Stock). Performance Shares, which represent \$23.052 million of the Company's projected LTIP expense, are granted annually as detailed on Exhibit A-21, Schedule K5. In contrast, 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)

Staff's proposal is 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).

AG witness Coppola proposed to exclude 40% of incentive compensation expense relating to operating measures based on his analysis of the operating performance levels achieved for the years 2017 through 2021 (8T 4880-4881; Exhibit AG-1.49). Mr. Cooper explained that Mr.

Coppola's analysis is flawed because it failed to recognize that while certain measures may produce results less than Target, other measures can produce results greater than Target. There are also various gradients of performance between Threshold and Maximum. Exhibit A-35, Schedule Z1 shows that for the last five years, the actual weighted performance was 96.5% for the AIP, and 83.4% for the REP (Cooper, 7T 1859-1860).

The Company's initial filing also included Exhibit A-21, Schedule K7, which reflected the Company's actual operating measures performance for 2016 through 2020 for the AIP and REP for all employee groups.⁸⁹ It showed that the average of the annual operating performance results for 2016 through 2020 was 100.9% for the AIP, and 87.5% for the REP. The combined five-year average for both the AIP and REP was 94.2% (Cooper, 7T 1842).

This average annual performance method is more accurate than Mr. Coppola's simplistic binary approach (either the target was met, or not), and it recognizes that actual payouts can fall within a wide spectrum of performance levels. Moreover, variations in year-to-year performance further reflect the ambitious goals set each year to motivate ever-improving operating performance. It is not reasonable to assume that only 60% of operating performance measures will be achieved as the AG suggests. The Company's goal is to establish costs at levels that are likely to be achieved, so it is reasonable to assume that the Company will, on an overall basis, achieve Target performance levels (Cooper, 7T 1860-1861).

The Commission previously relied on similar evidence to reject essentially the same argument that the AG repeated in this case. The Commission instead authorized DTE Electric's recovery of incentive compensation relating to operating measures, explaining in part: "The

⁸⁹ The 2021 AIP and REP operating measures and weighted performance are reflected on Exhibit A-21, Schedules K2 through K4 (Cooper, 7T 1824-1825).

Commission notes that DTE Electric provided evidence showing that the company has achieved performance targets for AIP at an average of 96.3% and for REP at an average of 82.8%, from 2012 to 2016. (7T 837). When looking at historical performance over a longer period, the Attorney General’s recommendation that 50% should be disallowed is simply not supported” (April 18, 2018 Order in Case No. U-18255, p 49). See also, May 2, 2019 Order in Case No. U-20162, p 93. The Commission’s older orders also recognize that incentive compensation is recoverable based on the type of programs that DTE Electric has developed and the type of evidentiary record that DTE Electric has presented in this case.⁹⁰

The Company recognizes that in DTE Gas’s most recent rate case, the Commission adopted the AG’s proposed 20% disallowance of operating measures, along with a deferral mechanism (December 9, 2021 Order in Case No. U-20940, p 163, relevantly stating: “In addition, the Commission authorizes DTE Gas to implement a two-way tracker mechanism, which will require refunds to customers if the 20% target level is not achieved or will allow the company to recover additional funds if it exceeds the 20% target level, up to a maximum of 100% target level. DTE Gas shall record the over- or under recovery, compared to the 20% base, in a regulatory asset or regulatory liability to be included in the company’s next general rate case”).

⁹⁰ The Commission long ago recognized that: “Executive bonuses have often been viewed as an appropriate cost of operating a utility” (October 28, 1993 Opinion and Order in Case Nos. U-10149 and U-10150, p 57 (rejecting the ALJ’s total exclusion recommendation; adopting Staff’s 50/50 sharing proposal; and advising DTE Gas that “future approval of an incentive bonus plan like this requires a showing that it will not result in excessive costs and that the benefits to the utility’s ratepayers will be commensurate with those costs”). See also, for further example, Case No. U-17767, where the Commission approved DTE Electric’s recovery of costs attributable to operating measures, stating that:

[I]n the immediate case, the Commission finds that DTE Electric provided convincing evidence that the operating (non-financial) measures for the AIP and REP provide appreciable benefits to customers, and meet the standard set forth in the April 28, 2005 order in Case No. U-13898 (April 28 order) and the December 23, 2008 order in Case No. U-15244 (December 23 order)... [December 11, 2015 Order in Case No. U-17767, p 76.]

The Company is agreeable to this alternative cost recovery, but only if the asymmetrical distribution of risks is eliminated. Therefore, if the Commission adopts a deferral process for incentive compensation expense, that process should be modified to eliminate the 100% performance level cap (Cooper, 7T 1862).

Energy Michigan witness Zakem proposed the disallowance of incentive compensation expense for all measures in which the costs are greater than the benefits (8T 4497-4500). The Company disagrees. In addition to the discussion above, the Energy Michigan proposal is flawed for two reasons.

First, the cost/benefit analysis reflected in Exhibit A-21, Schedule K6 represents only the reasonably-quantified financial benefits of the Company achieving target performance for each of the metrics included in the incentive compensation plans. It is also important to recognize that certain measures provide benefits to customers but evade specific quantification. For example, the quantifiable benefits of the MPSC Customer Complaints measure is only \$228,000 based on time savings but does not include additional unquantifiable benefits to customers (such as avoidance of frustration) or savings by the Commission resulting from a reduction in complaints (Cooper, 7T 1863-1864).

Second, Energy Michigan's proposal is a new, unreasonable, and unsupported interpretation of the Commission's standard for recovering incentive compensation expense, which has consistently assessed the net customer benefits on an aggregated basis, and not the net benefits for each measure (Cooper, 7T 1863-1865).

In summary, DTE Electric has demonstrated in detail that the customer benefits of its incentive compensation plans significantly outweigh their costs, that the total compensation is reasonable based on comparison to the Company's peers, and that there is no valid reason to

disallow the Company's requested cost recovery. Therefore, based on the evidence in this record 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.

D. Depreciation and Amortization

DTE Electric seeks to recover \$1,087.9 million of depreciation and amortization (D&A) expense for the projected test period (Exhibit A-13, Schedule C6). Ms. Uzenski supported the Company's projected D&A expense, explaining that includes book depreciation, which is based on existing plant balances, plus new capital expenditures and assumed retirements, using a half year convention. Depreciation expense was calculated using the rates authorized by the Commission in Case No. U-18150 (Uzenski, 7T 2716).

The projected \$134.6 million D&A increase was due primarily to \$205.6 million for capital in-service movement. Software amortization also increases in the projected period. These increases are partially offset by approximately \$82.9 million for plant (Uzenski, 7T 2717).

As discussed in Section I, the Company has now made a \$23.0 million reduction to its capital projections. This reduction correspondingly reduces the Company's projected D&A expense by \$1.8 million. These adjustments result in a revised projected D&A amount of \$1,086.1 million, which should be approved by the Commission.

E. Property and Other Taxes

DTE Electric seeks to recover \$307.7 million of property tax expense for the November 2022 through October 2023 projected test period (Wisniewski, 7T 1480; Exhibit A-13, Schedule

C1, column (e), line 6). This amount is calculated by taking 2/12ths of the 2022 calendar year expense, plus 10/12ths of the 2023 calendar year expense (7T 1481).⁹¹

DTE Electric projects a \$48.6 million Other Tax Expense for the projected test year, consisting of payroll taxes (\$36.6 million), Public Utility Assessment fees (\$11.9 million), and miscellaneous other taxes (\$0.1 million) as shown on Exhibit A-13, Schedule C7, column (j), lines 2-5 (Wisniewski, 7T 1481).

F. Income Tax Expenses

DTE Electric seeks a total income tax recovery of \$137.6 million (Wisniewski, 7T 1481). DTE Electric projects a \$83.2 million federal income tax (FIT) expense for the projected test year, based on a 21% FIT rate (Wisniewski, 7T 1472, 1481-1482; Exhibit A-13, Schedule C8, line 59). DTE Electric projects a \$51.8 million Michigan Corporate Income Tax (MCIT) expense, based on a 5.88% rate (7T 1472, 1483; Exhibit A-13, Schedule C9, line 15). DTE Electric projects a \$2.6 million municipal income tax expense, based on a 0.33% composite municipal income tax rate (Wisniewski, 7T 1472, 1483; Exhibit A-13, Schedule C10, line 11).

The overall methodology for amortizing the Tax Cuts and Jobs Act (TCJA) tax regulatory liability for excess deferred taxes (reflected in Exhibit A-13, Schedule C8.1) is consistent with the May 8, 2020 Order in Case No. U-20561. Amortization for the November 2022 through October 2023 test period reduces tax expense by \$49.9 million (Wisniewski, 7T 1482; Exhibit A-13, Schedule C8, line 55).

⁹¹ The projected 2022 property tax liability is \$296.6 million (Wisniewski, 7T 1478; Exhibit A-13, Schedule C7.1, column (c), line 54). The projected 2023 property tax liability is \$311.9 million (Wisniewski, 7T 1479; Exhibit A-13, Schedule C7.1, column (e), line 56). Property tax *expense* is the amount of property taxes deducted for book purposes. Property tax *liability* is the amount of property taxes payable to local governments. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years, and is generally based on the fiscal years of the various taxing jurisdictions to which property taxes are paid (Wisniewski, 7T 1472-1473, 1480).

IX. OTHER REVENUE RELATED ISSUES

A. Accounting Requests

As discussed elsewhere regarding Employee Pension and Benefits Expenses, the Company requests the continuing deferral of net OPEB expense to a regulatory liability, and a similar mechanism for deferral of pension expense (Uzenski, 7T 2772).

The Company proposes to continue deferring certain O&M costs related to the ADMS software to a regulatory asset. The deferred costs are reflected on Exhibit A-12, Schedule B5.4, page 1, line 25. The regulatory asset will be amortized over a fifteen-year period beginning with the year after the in-service date. The amortization expense is expected to be \$764,000 in the projected test year (Uzenski, 7T 2715; Exhibit A-13, Schedule C5.6, line 11, column (j)).

The Commission's February 18, 2021 Order in Case No. U-20793 (DR 2019 Reconciliation) approved a settlement reflecting an under-recovery of \$3 million recorded as a regulatory asset in the first quarter of 2021 and provides for recovery in base rates via inclusion as amortization expense. The Company proposes that the regulatory asset be collected over three years (Uzenski, 7T 2717).

As discussed elsewhere regarding Charging Forward, the Company requests to include rebates for the expanded Charging Forward program in the previously approved regulatory asset (Uzenski, 7T 2761, 2772).

As discussed elsewhere regarding TOU full implementation, the Company proposes to defer the one-time project costs associated with the Company's TOU full implementation as a regulatory asset, using account 182.3, Other Regulatory Assets, to record the deferral. The Company proposes to amortize the deferred costs over a five-year period commensurate with their recovery in base rates. (Uzenski, 7T 2761-2762, 2772; Exhibit A-12, Schedule B4, line 34).

As discussed elsewhere regarding Energy Assistance, the Company initially proposed a mechanism that would allow the Company to carry over any unspent RIA and LIA credits from one year to the next. The Company agrees with Staff that it is appropriate to record a regulatory liability for underspending, but proposes that any underspent amounts be netted against any regulatory assets recorded for overspent amounts such that a cumulative net balance is carried forward for disposition in a future rate case (Uzenski, 7T 2772, 2787-2788).

Company witness Cooper explained that on September 9, 2021, President Biden issued a plan to combat COVID-19 that included an announcement that the Occupational Safety and Health Administration (OSHA) was to develop a rule requiring all employers with 100 or more employees to ensure their workforce is fully vaccinated or require any workers who remain unvaccinated to produce a negative test result at least weekly before coming to work. On November 5, 2021, OSHA issued an Emergency Temporary Standard that implemented these requirements. There could be significant compliance costs (for example, to test unvaccinated employees), but litigation could result in the affirmation, modification, or elimination of the requirements. Thus, there is too much uncertainty to develop a reliable estimate of costs (Cooper, 7T 1811-1812). To address this uncertainty, the Company proposes to defer the actual expense for future recovery using Account 182.3, Other Regulatory Assets (Cooper, 7T 1813; Uzenski, 7T 2770, 2772).

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 prudence in a subsequent general rate case (Crozier, 7T 2359-2362; Uzenski, 7T 2770).

Kroger witness Bieber suggested that allowing the Company to defer costs for customer outage credits would reduce the Company's incentive to restore service quickly (8T 460). To the contrary, the Company is dedicated to restoring service to customers as quickly as possible, regardless of whether it receives recovery of any outage credits (Crozier, 7T 2380). The Company similarly disagrees with Kroger's suggestion that deferral is unnecessary because the Company could request a waiver from the rules (Bieber, 8T 4651). A waiver would require a contested case hearing, which would be administratively burdensome and inefficient for the Commission and all parties involved. The type of outage causes for which the Company is requesting credit deferral are also unlikely to occur en masse. The Company's proposal (defer credits paid as they occur, with collective review in a rate case) provides adequate prudence review, and is the most efficient process for this purpose. Moreover, under Kroger's proposal, if the Company received a waiver, then the Company would not have to pay credits, and customers would not receive them. Under the Company's proposal, customers receive the credits, and the Company simply has an opportunity to recover the costs after they are reviewed in a future proceeding (Crozier, 7T 2381-2382).

B. Line Loss Study

In the Company's last general rate case, the Commission ordered that "[i]n its next general rate case, DTE Electric shall provide a new line loss study, as described in this order." (May 8, 2020 Order in Case No. U-20561, p 249).⁹² The Commission further explained:

⁹² A line loss study determines the losses in the electrical system that occur between the point of generation and end-customer usage (Robinson, 7T 1558).

The Commission supports the need for an accurate and timely line loss study and adopts the recommendation of the ALJ that DTE Electric shall conduct a line loss study before its next rate case, and should endeavor to complete a marginal loss study as recommended by the MEC Coalition “or provide a detailed explanation of what appropriate limitations it imposed on its analysis. PFD, p. 365. As the ALJ noted, “the company’s distribution system is a focus of substantial investment for the utility, and additional insight into the operation of that system would seem to be valuable.” *Id.*, pp. 365-366. [May 8, 2020 Order in Case No. U-20561, p 211.]

Accordingly, the Company commissioned Burns and McDonnell based on the firm’s expertise in performing electrical system studies and line loss studies to assist in this effort. The methodology first generated a total loss estimate from billing data by subtracting total customer sales from the MISO Net System Output (NSO). Then the Company split the study into five components (generation, transmission, subtransmission, distribution primary, and distribution secondary) and performed technical analyses to determine losses and validate results for each component, Exhibit A-28, Schedule R1 provides the results (page 1 in MW; page 2 in MWh). (Robinson, 7T 1558-1564. See also 7T 1568).

The Company also conducted a marginal line loss study that augments the above-described line loss study with: (1) Losses at the Annual Peak Demand; (2) Losses at 2% below the Annual Peak Demand; and (3) Losses at 2% below the Annual Average Demand. The results are included in Exhibit A-28, Schedule R1, page 3 (Robinson, 7T 1565). DTE Electric evaluated, but did not incorporate, all of the Commission’s suggestions from Case No. U-20561 (quoted above, referencing MEC Coalition witness Jester’s recommendation) because the suggested approach would require significantly more time and resources, plus the models would require constant updating due to the changing characteristics of the electrical system and variables related to customer behavior (Robinson, 7T 1567-1568). Mr. Robinson explained in part:

In aggregate the Commission’s study suggestions would increase the number of simulations necessary from 72 in the study DTE Electric conducted, to approximately 2.1 billion just within the distribution primary system. Based on

industry examples, the full study to satisfy the Commission's request would take a minimum of 18 months to complete and could exceed \$15 million. Additionally, the suggested approach would lead to outdated and most likely inaccurate results due to the continuous physical changes to DTE Electric's system. [Robinson, 7T 1566.]

The Company's approach provides sufficiently detailed and accurate information on how changes in load affect each system component. The Company's approach also solves the problem of changing system characteristics and customer behavior variables by creating a sustainable method to re-evaluate the electrical system. Thus, the Company's marginal line loss study provides data on marginal line losses in a practical way, with meaningful results that can be used in this case (Robinson, 7T 1568-1569).

ABATE witness Andrews proposed that "DTE should be required to update the 2019 Line Loss study to explicitly calculate the 4CP and 12CP loss factors based on the monthly peak demands" (8T 2996). Exhibit A-28, Schedule R1 uses monthly average values for line loss factors. The Company will consider exploring a revised methodology for calculating line loss factors in the future, but does not support including the loss factors calculated by witness Andrew because they have not been reviewed and are based on incomplete system values (Asghar, 7T 1465).

X. SUMMARY OF REVENUE DEFICIENCY AND REQUESTED RATE RELIEF

Based on the adjustments described above in Section I, DTE Electric supports and requests approximately \$367.9 million in rate relief. See Attachments A and B.

XI. COST ALLOCATION AND RATE DESIGN

A. DTE Electric's Cost of Service Study Supports the Company's Rate Design Proposals

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 typical process to develop a UCOS study consists of three steps: (1) functionalization (which assigns all costs to the major functions, *i.e.* power supply and distribution);⁹³ (2) classification (which divides these costs into customer-related costs, demand-related costs, and energy-related costs); and (3) allocation (which apportions the cost classifications to the respective classes of service based on the class's responsibility for the incurrence of these costs). (Maroun, 6T 1029-30).

The UCOS study contains 16 basic externally developed allocation schedules (Maroun, 6T 1034). Company witness Asghar developed 11 allocation schedules for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). She supported these allocation schedules as reasonable, and as accurately representing the load characteristics for customers receiving power supply and/or distribution service from DTE Electric (Asghar, 7T 1455-1459). Company witness Maroun used Ms. Asghar's allocation schedules, plus five more that he developed, to determine rate class cost responsibility (Maroun, 6T 1034).

⁹³ Power supply (generation and transmission) includes costs associated with the Company's generating plants, fuel, purchased power, and the transmission services that it receives from MISO and ITC. Distribution includes the costs associated with the Company's distribution system, which generally operates at voltages of 40kV and below, and includes customer service expenses (6T 1030).

Mr. Maroun explained how he functionalized DTE Electric's costs (6T 1030-1032; Exhibit A-16, Schedule F1.3), and how the UCOS allocates costs to DTE Electric's various customer classes (6T 1032-1035). He further testified that DTE Electric will experience a jurisdictional revenue deficiency of approximately \$388.2 million in the year ending October 31, 2023, consisting of an \$18.0 million total production revenue deficiency, and a \$370.2 million distribution revenue deficiency. Exhibit A-16, Schedule F1.1 shows the production-related revenue (sufficiency)/deficiency associated with each consolidated cost-of-service rate class. Exhibit A-16, Schedule F1.2 shows the distribution-related revenue (sufficiency)/deficiency by cost-of-service voltage class (Maroun, 6T 1036-1037).

The Company proposed 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). He further explained that DTE Electric uses three allocation bases for distribution: (1) demand, (2) customer, and (3) those based on special studies.⁹⁴ 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 Signals⁹⁵), consistent with the allocation method that the Commission approved in Case No. U-20561 (Maroun, 6T 1039). Exhibit A-16, Schedule F1.4 calculates monthly

⁹⁴ Cost causation for distribution is determined by the parameters used to design and build the system. Distribution planning takes future load growth and reliability into account, so the system will generally have the capacity to support additional loads. Therefore, once installed, distribution system costs are generally not affected by increases or decreases in either demand or energy until the circuit limit (demand threshold) is approached. When viewed prospectively, however, distribution system design cost is caused by the number of customers served and the maximum demand placed on the system at a given voltage level (Maroun, 6T 1040).

⁹⁵ 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).

Company witnesses Bellini and Maroun also addressed MAUI witness Bunch's apparent misperceptions regarding test-year Plant in Service (PIS) and depreciation, and explained that his corresponding recommendations should be rejected because there is no basis to depart from long-standing and correct methodologies (Bellini, 7T 1744-1747; Maroun, 6T 1061-1065).

customer charges by voltage level, using the Staff method approved in the May 8, 2020 Order in Case No. U-20561 (Maroun, 6T 1048, 1042-1043).

Exhibit A-16, Schedule F3 shows present and proposed rate designs and corresponding revenues by rate schedule. Exhibit A-16, Schedule F4 calculates typical bills for each rate schedule based on the Company's present and proposed rates. Exhibit A-16, Schedule F8 contains the proposed rule and tariff sheet changes (Willis, 6T 923, 932). Mr. Willis summarized various relatively minor changes to residential rates (6T 933-934) and other tariff changes (6T 964-965). Mr. Robinson supported the Company's proposed clarifications to tariff provisions in section C of its rate book for service connections to align with Company service standards (7T 1569-1572). Further detail is discussed below in the context of the specific proposals.

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 requirements, and further recommended that rates should then be recalculated with the new billing determinants (Lucas, 8T 3597).

The Company disagrees because its method to allocate residential sales is consistent with the method used in past cases, including Case No. U-20561. While CEO witness Lucas apparently agrees 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), he suggested that 2020 was abnormal because of COVID. Nonetheless the Company's forecasting is accurate as discussed above, and Mr. Lucas does 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. 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).

The Commission adopted the 4CP 75-0-25 method for allocating certain production costs in Case No. U-17689 (in accordance with 2014 PA 169) and has continuously applied it in subsequent DTE Electric rate cases, Case Nos. U-17767, U-18014, U-18255, U-20162 and U-20561. The Commission also reminded future parties of the standard "that any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes" (May 2, 2019 Order in Case No. U-20162, p 129, quoting the January 31, 2017 Order in Case No. U-18014, p 100).

AG witness Dismukes recommended that "the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 55-0-45 cost allocation methodology" (8T 4938). He made a nearly identical recommendation in Case No. U-20561 (at 9T 2857), which the Commission rejected, finding that "the record evidence is insufficient to overcome [MCL 460.11(1)'s] statutory allocation, as no party adequately demonstrated that a different methodology more adequately reflected the actual cost of service" (May 8, 2020 Order in Case No. U-20561, p 220).

Mr. Dismukes' present 4CP 55-0-45 recommendation similarly lacks a sound foundation because it is based primarily on system load factors, which is not an equivalent peaker method as described by the NARUC Electric Cost Allocation Manual (Maroun, 6T 1059; Exhibit A-39,

Schedule BB2). The analysis presented in Exhibit AG-2.5 is also not an approximation of the equivalent peaker method. The NARUC manual describes two methods for allocating costs using equivalent peaker methods, which are based on (1) the original cost to install generating units, and (2) a comparison of the rate bases of base load and peaker units. In contrast, Exhibit AG-2.5 determines the demand/energy split by (1) using capacity factors, and (2) comparing a levelized total cost to the MISO CONE price. Mr. Dismukes did not present an equivalent peaker analysis and he failed to demonstrate that the current production cost allocator is not cost based. As such, the 4CP 75-0-25 production cost allocator should remain unchanged (Maroun, 6T 1060).

AG witness Dismukes further recommended that “the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP [non-coincident peak] demands” (8T 4942). He made the same recommendation in Case No. U-20561 (at 9T 2865). The Commission agreed with the ALJ’s recommendation to reject the AG’s proposal as insufficiently supported by a small sample of 18 cases, and that the AG could raise the issue again with additional evidence (May 8, 2020 Order in Case No. U-20561, pp 224-225).

Instead, the AG presented the same evidence, so there is no basis to reconsider the issue. The Company also disagrees that a change is either necessary or appropriate. First, the basis for Mr. Dismukes’ recommendation is not robust (18 general rate cases over an eight-year period, out of hundreds of rate cases during that period). Further, simply because a method is used by another utility or in another state does not, in itself, justify its use for DTE Electric. In sum, Mr. Dismukes did not present meaningful evidence that could support deviating from the current, well-established practice (Asghar, 7T 1462-1464).

Staff “recommends 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 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. Staff’s total revenues proposal 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, Staff’s proposal should be rejected as unfounded and contrary to ratemaking principles (Maroun, 6T 1067-1068).

Staff “recommends that the Company be required, in its next rate case, to propose a method for allocating the cost of the AMI communication system between the billing function and any other functions it is utilized for (for example, to deliver load control signals as discussed by Company witness Phillip L. Smith), including all said functions. In Staff’s opinion, insofar as the AMI communication network is used for something other than billing, an appropriately allocated portion of that cost should be removed from the calculation of the customer charge, the non-transmitting meter charge offset, and allocated on a basis consistent with that use rather than how it is currently allocated” (Revere, 8T 5141-5142).

The Company disagrees because although AMI meters provide ancillary benefits to customers, the fact remains that (1) the addition of a customer requires investment in an AMI meter, and (2) costs are predominately driven by the supply of service to customers. The Commission also denied a similar proposal in a prior proceeding (December 17, 2020 Order in Case No. U-20697, p 285). Therefore, the most appropriate approach is to continue classifying 100% of meter costs as customer related, and recover these costs through customer charges, as proposed by the Company and utilized in tariffs approved by the Commission in prior rate cases (Maroun, 6T 1069-1070).

MNSC witness Jester proposed that the Commission direct the Company and Staff to “build up a database for further analysis” based on information about other utilities in other states (8T 3739). The Company disagrees because this would be a wholly unnecessary duplication of the existing rate case process. Further, the Company’s rates are required to be set pursuant to Michigan law and based on the Company’s unique costs and other circumstances, as discussed above in section IV. Therefore, MNSC’s proposal should be rejected (Crozier, 7T 2383-2384).

B. Revenue Requirements by Unit/Grouping Study (Plant Study)

The Commission adopted the 4CP 75-0-25 method for allocating certain production costs⁹⁶ in Case No. U-17689 (in accordance with 2014 PA 169), and has continuously applied it in subsequent DTE Electric rate cases, Case Nos. U-17767, U-18014, U-18255, U-20162, and U-20561. When the issue arose in DTE Electric’s last general rate case, the Commission relevantly stated:

[T]he Commission did not determine that the 4CP 75-0-25 production cost allocation method was not cost based in Case No. U-20162, and again reiterates the statutory requirements set forth in MCL 460.11(1) which states, in pertinent part:

⁹⁶ The only production costs allocated using 4CP 75-0-25 are plant and plant-related costs. Other production costs are allocated differently or assigned directly (Maroun, 6T 1028, 1042-1043).

The Commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs using the 100% demand method of cost allocation. The Commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

While numerous methodologies were presented, the Commission finds that the record evidence is insufficient to overcome this statutory allocation, as no party adequately demonstrated that a different methodology more appropriately reflected the actual cost of service. [May 8, 2020 Order in Case No. U-20561, p 220.]

The Commission indicated, however, that it “remains open to reviewing alternative methodologies in future rate cases,” and further stated:

[T]he Commission agrees with the ALJ’s determination that the company should be required to provide revenue requirements by plant/unit in its next general rate case. If some or all necessary data is unavailable by plant/unit, DTE Electric should, in consultation with the Staff, determine a reasonable method for allocating the available data to plants/units, and provide explanations and support in its next rate case filing. [May 8, 2020 Order in Case No. U-20561, pp 220-21.]

Accordingly, Company witness Mr. Lacey explained and supported the Company’s revenue requirements by unit/grouping study (Plant Study) (7T 2593-2599; Exhibit A-32 Revised). He explained that he developed the Plant Study by starting with the Company’s production UCOS, but instead of allocating costs to rate classes like in a typical UCOS, he allocated the same costs to the forty-two (42) generation units/groupings (17 steam/fossil units, 1 nuclear unit, 1 hydro unit, 21 peaker/other units, Midwest Energy Resource Company (MERC), and Transmission) (7T 2595). Thus, total production costs shown in Exhibit A-32 Revised, column (a) match, line by line, Exhibit A-16, Schedule F1.1 (the Company’s forecasted production unbundled UCOS study), and are allocated to DTE Electric’s forty-two (42) production generation unit groupings (7T 2594). Mr. Lacey further explained how he allocated costs (7T 2595-2599) and that Staff’s recommendations are incorporated into Exhibit A-32, Schedule W1 (7T 2593).

MNSC witness Jester proposed that the Commission require DTE Electric to perform the plant study in future rate cases (8T 3847). Mr. Lacey explained that the genesis of the requirement that the Company file a plant study in this case was grounded in the need for parties to provide an Equivalent Peaker Method (EPM) study in order to support their alternative demand/energy splits for the production plant allocator. The Company should not be required to provide a plant study in future cases because it is time consuming and unnecessary. Plant accounting records are now maintained by the Company and available for any other party to perform their own EPM study. The full plant study is also not needed to perform an EPM analysis. Moreover, no party used the plant study or available data in this case to perform an EPM study. The Company received over 5,000 audit and discovery questions in this case, but only one related to the plant study itself. There is no sound basis to require the Company to devote the significant time and resources needed to perform the plant study simply because a party might be curious or might possibly find a use for it (Lacey, 7T 2602-2603).

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).

More specifically, Mr. Maroun used the methodology for calculating gross energy sales net of fuel, as determined in prior rate cases (6T 1028, 1043-1044). Mr. Burgdorf further explained the underlying calculations (4T 120-124) and summarized that the total projected 2022 wholesale

energy revenue of \$1.693 billion, net of \$1.033 billion in fuel-related costs, equates to \$659 million wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26 Revised, Schedule P3, Line 26. The reconciliation of the net sales benefit difference for 2020 of \$351.4 million (Exhibit A-26 Revised, Schedule P4, Line 12, column (d)) was subtracted from the 2022 projection resulting in an amount of \$308 million (Exhibit A-26, Schedule P3, Line 28) (Burgdorf, 4T 124).

Mr. Maroun further explained that he reduced the capacity charge revenue requirement for non-capacity related purchased power (Exhibit A-16, Schedule F1.5 Revised, lines 3 and 4). He did so because these costs are for energy charges purchased from MISO for Rider 3 and Rider 10 (line 3) and other energy related purchased power (line 4) (Maroun, 6T 1044).

Mr. Maroun adjusted variable O&M (Exhibit A-16, Schedule F1.5 Revised, line 5) by including only the 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). This is consistent with Chapter 4 of the NARUC Manual, which reflects that labor expenses are considered demand-related, while material expenses are considered energy-related. Thus, only material-related costs are variable (Maroun, 6T 1045).

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).

MNSC witness Jester asserted that Mr. Lacey made errors in his plant study (Exhibit A-32 Schedule W1, discussed above), which he recalculated in Exhibit MEC-9. Mr. Jester then used his Exhibit MEC-9 to re-calculate Mr. Maroun's calculation of capacity costs for purposes of the

capacity charge revenue requirement (Exhibit A-16, Schedule F1.5), and produce Exhibit MEC-11 (8T 3841-3844). Mr. Jester's various re-calculations of the plant study and capacity charge produced a 65% ratio based on Exhibit MEC-11 line 8 divided by line 11 ($\$1,196 \text{ million} / \$1,846 \text{ million} = 65\%$). (Jester, 8T 3846-3847). He then used the 65% ratio to support the proposition that the 4 CP 75-0-25 method for allocating plant costs should be changed "by allocating 65% of production plant costs based on 4CP and 35% based on energy" (Jester, 8T 3848).

Mr. Lacey responded by explaining that Mr. Jester's allegations and alternative calculations in Exhibit MEC-9 were incorrect (such as treating transmission costs as fuel costs, which is contrary to well-established and well-reasoned commission precedent) and/or inconsequential, particularly since MNSC did not use the plant study to support an alternative production cost allocator or EPM analysis, which was the point of doing the plant study in the first place, as discussed above (Lacey, 7T 2603-2607).

Mr. Maroun further explained numerous errors that Mr. Jester made in recalculating the capacity charge in Exhibit A-16, Schedule F1.5 (6T 1050-1057). For example, Mr. Jester's use of amounts from as-filed Exhibit A-26, instead of Revised Exhibit A-26 (which was filed on March 16, 2022) increases MNSC's proposed capacity revenue requirement by \$431.9 million, from \$1,196.3 million to \$1,538.2 million (Maroun, 6T 1057; Exhibit A-39, Schedule BB1 Revised). Using corrected values from Exhibit A-39, Schedule BB1 Revised changes Mr. Jester's asserted 65% ratio to 83% ($\$1,538 \text{ million} / \$1,846 \text{ million} = 83\%$), so MNSC's own methodology supports a contrary result than what MNSC proposes (Maroun, 6T 1057-1058).

Even more fundamentally, it would not be appropriate to allocate over \$11 billion of plant costs based on such a volatile ratio. The Commission has approved the current production plant allocator in every rate case since Case No. U-17689. Also, as noted above, the Commission stated

that parties proposing changes to the production plant allocator must present an equivalent peaker method analysis or show that rates using 4CP 75-0-25 are not cost based (May 2, 2019 Order in Case No. U-20162, p 129). MNSC did neither. Therefore, MNSC's unfounded and otherwise flawed proposal should be rejected (Maroun, 6T 1058).

Energy Michigan witness Zakem proposed that "any expenses other than fuel should be removed from the "net of projected fuel" calculation (8T 4505). 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. This treatment 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).

Mr. Zakem further proposed that when calculating the SRM capacity charge, the data for the projection should be for the same year as the data for the actuals (8T 4512). The Company disagrees because, for example, the projection for the 2019 PSCR year was embedded in rates that were approved in Case No. U-20561 (a general rate case where capacity expense is established), and which the Company charged throughout 2021. The Company's capacity charge true up compares the actual energy sales net of fuel for the year to the projection of that data that was embedded in its rates that it charged to its customers during that year. (Crozier, 7T 2392-2393).

Mr. Zakem further proposed that the Commission eliminate the true-up calculation when calculating capacity charges as long as the previous charge has not been applied to any party, presumably meaning an Electric Choice customer (8T 4510). The Company disagrees because the

enabling statute⁹⁷ does not say that its requirement to include a capacity charge true-up is contingent on whether an Electric Choice customer paid a capacity charge during the period being reconciled. Therefore, the energy sales net of fuel true-up must be included in the calculation of the capacity charge (Crozier, 7T 2393-2394).⁹⁸

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). The Company disagrees, because, 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).

⁹⁷ MCL 460.6w(4) states:

The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in section (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

⁹⁸ Statutes must be applied as written. *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); *Amb's v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

The statute also uses the term “shall,” which denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion *Macomb Co Rd Comm'n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) (“the word ‘shall’ is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion”).

D. Residential Rate Design Proposals

Exhibit A-16, Schedule F3 shows the present and proposed rate designs and corresponding revenue by rate schedule. In the Company's rate case filed in 2014, Case No. U-17767, MPSC Staff recommended, and the Commission approved, variable distribution rates designed such that all customers in the Residential Secondary class would have the same rate, with the caveat that a cap was applied to limit the increase of any specific variable distribution rate. This method was again proposed and approved in the Company's subsequent rate cases, Case Nos. U-18014, U-18255, U-20162 and U-20561. Consistent with the Order in Case No. U-20561, the Residential Secondary rate schedules (except for D1-A and D1-B, discussed below) now all have the same distribution rate, so no cap is applied in this case (Willis, 6T 923-925).

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).⁹⁹

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

⁹⁹ 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).

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 D1-A's power supply capacity rate is a "flat" per kWh energy charge that remains constant regardless of date and time. For Rate 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 (and still maintains) full implementation of TOU rates using proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), which mimics the structure of Rate D1-A (Foley, 6T 1137, 1145). The Company proposes to apply TOU pricing to only the non-capacity portion of power supply because the most appropriate costs to recover through per kWh TOU pricing are fuel and energy-related purchased power, both of which are contained in the non-capacity portion of power supply costs. Power supply capacity costs are most appropriately recovered through a demand-based charge. These rate designs best align with the underlying drivers of costs for the respective cost type, and therefore send the most accurate pricing signals to customers to encourage efficient, low-cost asset use. A flat per kWh energy price for the capacity portion of power supply would replace the "inverted block rate" in the current D1 rate. The Company's proposal retains the D1 rate structure for delivery costs (Foley, 6T 1125-32, 1139-40).

Applying TOU pricing to only power supply non-capacity rates will help limit potential bill impacts as customers get comfortable with the new rate structure. The Company's proposal to have the TOU structure effective year-round will also provide consistent messaging and price signals to customers that will encourage off-peak utilization of energy, which will be important as the

deployment of electric vehicles continues to accelerate. Retaining the TOU structure in non-summer months also reflects that even in these months, there is a meaningful difference between on-peak and off-peak market energy prices (although the price differential is greater in the summer months, so the Company proposes “summer” and “non-summer” pricing). Thus, the Company’s proposal takes an important step in more broadly establishing TOU rates, while also mitigating potential negative customer impacts (Foley, 6T 1141-1143).

Staff and some Intervenors proposed to extend TOU pricing beyond power supply non-capacity costs. In response, 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). The Company does not oppose extending TOU pricing to power supply capacity rates in the manner proposed by the Company (Foley, 6T 1190-1192).

Rate Schedule D1.11 is designed to be revenue neutral to the D1 rate rates proposed in this case. Exhibit A-16, Schedule F3, p 11, reflects the design of the rate (Willis, 6T 927-928).

Staff proposed that it would be more appropriate to utilize the percentage difference in LMPs to guide rate differentials than the Company’s initial proposal to use absolute differentials (Revere, 8T 5141), and to begin by collecting power supply capacity costs through rates that are 50% higher in the summer on-peak period (Revere, 8T 5134). The Company agrees in part. The Company’s alternative proposal supports varying both power supply capacity and non-capacity rates by the percentage difference in LMPs, which would result in approximately a 64% summer and 15% winter power supply differential. The Company does not agree that capacity rates should vary only in the summer months. The rate structure should be consistent year-round, reflecting the difference in on-peak and off-peak capacity costs in the non-summer months Accordingly, the

Company recommends that both summer and non-summer months vary capacity and non-capacity by the appropriate percentage LMP. This pricing differential would apply to rate D1.11, and the non-capacity differential would apply to D1.12 power supply non-capacity rates (Willis, 6T 971-972).

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 because witness Lucas’ commentary and recommendation are based only on the Company’s initial proposal (vary only the power supply non-capacity rates by the absolute difference of LMPs). The Company’s alternative proposal would vary both power supply and non-capacity rates based on the percentage difference of LMPs, as discussed above. Therefore, the Commission should reject witness Lucas’ proposal and approve the Company’s 3% shift. 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, and will propose billing determinants in future rate cases after sufficient reliable historical information becomes available. (Willis, 6T 977-978).

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 proposes to utilize 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.¹⁰⁰ 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. The Company anticipates that a phased transition would occur in the first half of 2023 and expects to complete all customer transitions to the D1.11 rate by May 31, 2023 (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.

The one-time project costs associated with the Company’s TOU full implementation 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).

¹⁰⁰ 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).

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, and related cost recovery should be approved.¹⁰¹

2. Rate D1.12, the residential “Stable Bill Service Level” demand-based tariff

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 did not approve them, stating:

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.]

Thus, the Company does not currently offer any residential rate schedule that utilize demand rates or demand-based charges. Demand-based rates benefit customers by providing a third way to 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).

The Company proposes to establish Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level), which would be a voluntary tariff available to all residential customers. The D1.12 rate has 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

¹⁰¹ 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).

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 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).

As indicated above, the Company anticipates that TOU Full Implementation will occur in the first half of 2023. To avoid potentially overwhelming and/or confusing customers, the Company anticipates that it would make the proposed D1.12 rate available in the first quarter of 2024. This would give the Company time to complete and stabilize its TOU Full Implementation and give customers time to get comfortable with TOU rates before an additional rate option becomes available (Foley, 6T 1166).

Staff and some Intervenors raised various arguments against the proposed D1.12 rate. 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.

3. Energy Assistance

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 Low-Income Assistance (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). 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 Commission previously reduced the Residential Income Assistance (RIA) ¹⁰² enrollment level from 60,000 to 43,000 customers, and retained the 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).

Instead of simply deferring any amounts over the amount in base rates, the Company initially proposed a mechanism that would allow the Company to carry over any unspent RIA and LIA credits from one year to the next. If the credits issued in one year are lower than the base amount, then those unused credits could be used to fund assistance in the following year (Johnson, 5T 816). Staff disagreed, and instead suggested simply recording the unused credits as a regulatory liability (Braunschweig, 8T 5277). The Company agrees that it is appropriate to record a regulatory liability for underspending, but proposes that any underspent amounts be netted against any

¹⁰² The RIA provision provides a \$7.50 per month credit for qualifying customers, which offsets the current \$7.50 monthly service charge.

regulatory assets recorded for overspent amounts such that a cumulative net balance is carried forward for disposition in a future rate case. This would eliminate the need for the Company to file, and the Staff to review, a reconciliation for each two-year period as the Company had initially proposed (Uzenski, 7T 2787-2788).

The Company is also forecasting RIA enrollment of 61,745 customers in the projected test year. Current RIA enrollment is 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).

Staff instead proposed to limit the RIA enrollment forecast to 33,000, and move any RIA overflow onto LIA until the 32,000 LIA cap is reached (Braunschweig, 8T 5276). 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 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 Company disagrees because witness Johnson characterized current enrollment as of June 2021. The audit response and Part II filing 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. Therefore, the Commission should reject Staff's proposal, and instead adopt the Company's proposed forecast of 61,745 RIA credits and resulting revenues (Willis, 6T 975-976).

MI-MAUI witness Bunch's made various assertions about the Company's practice of deposits and collections (Braunschweig, 3418-3426), and on that basis recommended that the Commission should either "not allow rate recovery of the amounts required to administer the deposit program," or "disallow as part of the revenue requirement the interest expense from the approximately 7 in 10 deposits that proved to be unnecessary" (8T 3426).

Ms. Johnson responded by explaining numerous incorrect assumptions that Mr. Bunch made about the meaning of data, so his calculations were grossly inaccurate. He also failed to consider other matters, including that the intention of the deposit program is to reduce uncollectible expense, which produces benefits, and that the Company provides multiple means of notifying customers regarding why they are assessed a deposit. Therefore, Mr. Bunch's unfounded and otherwise flawed recommendations should be rejected (Johnson, 5T 835-838).

The Company also proposes changes to standardize and clarify the RIA and LIA sections of the tariff (Willis, 6T 932-933; Exhibit A-16, Schedule F8), and to update the tariff to conform with the billing rules as they relate to the age of senior citizen customers (Johnson, 5T 817-818).

Staff witness Braunschweig proposed tariff language changes that alter the Company’s current and approved application of the LIA credit with LSP, and proposed language referring to “rate setting purposes” that is not appropriate. In addition, Staff witness Braunschweig’s proposed language changes omit further clarification on the issuance of credit balance refunds. The Company provided language on how the tariff should read instead (Johnson, 5T 834)

4. Payment Stability Plan (PSP) Pilot

As a result of the Commission’s U-20561 Order and approval of the U-20929 ex-parte filing, the Company launched the Payment Stability Plan (PSP) pilot in January 2022. The two-year pilot targets a maximum of 2,000 low-income customers at or below 200% of the FPL for a percentage of income payment plan (PIPP). Customers who receive either gas or electric service from DTE Gas or DTE Electric will have flat bill payments equivalent to 6% of household gross income. Customers who receive both gas and electric service from DTE Gas and DTE Electric will have flat bill payments equivalent to 10% of household gross income. The pilot focuses on the importance of affordable energy as it relates to energy burdens for low-income customers, and will track data on a variety of characteristics for analysis (Johnson, 5T 819-820).

E. Commercial Secondary Rate Design Proposals

DTE Electric’s commercial secondary rate design is consistent with the methodology that the Commission approved in past cases. The Company does not propose any changes to secondary service charges, except for secondary standby service provided under Rider 3. The Rider 3 secondary service charge was erroneously reduced from \$90 to \$11.25 in Case No. U-20561. This change was not proposed by any party in that case, and was an oversight in the rate design. Secondary service provided under Rider 3 requires interval metering, so it is appropriate to have a service charge in line with other services requiring interval metering. Therefore, the Company

proposes to increase the secondary service charge under Rider 3 to \$70, in line with primary voltage service (Willis, 6T 941-942).

Mr. Willis also developed Rate Schedule D3.5 (EV Charging Hub Rate) for service provided by Company-owned electric vehicle charging infrastructure (6T 942-944; Exhibit A-16, Schedule F3, p 24 shows the rate design); new Standard Contract Rider No. 21 Utility Investment Tariff for Electric Bus Batteries and Charging Stations; and sponsored changes to the penalty provision language for Rate Schedule D3.3, Interruptible General Service Rate (6T 942-944; the proposed language is in Exhibit A-16, Schedule F8).

F. Commercial and Industrial Primary Rate Design Proposals

Mr. Willis described the Company's major primary rate schedules,¹⁰³ and explained that the Company's proposed primary delivery rates are cost-based by voltage level, as reflected on Exhibit A-16, Schedule F1.2. All primary rates will have the same \$/kW charges shown in column (h), except rates D10 and R1.1 and R1.2, which have energy-based delivery charges. Mr. Willis calculated energy charges for these rates that are equivalent to the proposed voltage level distribution charges (6T 946-947).

The Commission previously ordered the Company to explore clarifying the language of Rate Schedule D8, stating:

¹⁰³ Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission, or transmission voltage. Rate Schedule D6.2 is available to educational institution customer locations (schools, colleges and universities) desiring service at primary, sub-transmission, or transmission voltage. Rate Schedule D8 is the Company's primary voltage interruptible rate which is limited to 300 megawatts. Rate Schedule D10 is the Company's all electric school building rate (including electric space and water heating). Rider 1.1 and 1.2 are specific interruptible rates for customers operating electric furnaces for metal melting (Rider 1.1), or using electric heat as an integral part of manufacturing (Rider 1.2). The Company's Rider 3 rate provides standby service for various customers with generation facilities operating in parallel with the Company's system. Finally, Rider 10 is an interruptible supply rate available to customers with larger interruptible loads (Willis, 6T 945).

[T]he Commission finds that it is reasonable and prudent to require DTE Electric to continue its work with Staff, customers, and other stakeholders to review and revise the Rate D8 tariff language, and to reflect any changes through an *ex parte* filing, as part of a future rate case, and/or as part of the MI Power Grid initiative. [May 8, 2020 Order in Case No. U-20561, p 242.]

Accordingly, the Company engaged with Energy Michigan, ABATE and other stakeholders, including the Commission Staff, to clarify the language describing conditions of interruptions, notices of capacity deficiency and system integrity interruptions, and associated fees and/or penalties. The Company's proposed changes only clarify the existing terms and conditions of service, and do not change them. The changes proposed to the D8 system integrity language are also in Rate Schedule D3.3, Riders 1.1, 1.2, and 10. Mr. Willis also sponsored changes to the penalty provisions for Rate Schedule D8, as well as Riders 1.1, 1.2, and 10 (6T 948-949; Exhibit A-16, Schedule F8 reflects the proposed language).

G. Streetlighting Rate Design

Community Lighting provides Commission-approved tariff service to approximately 165,000 street lights on its E1 Option I Rate Schedule, approximately 200 municipally-owned street lights on its E1 Option II Rate Schedule, approximately 83,000 municipally-owned street lights on its E1 Option III Rate Schedule, and approximately 32,000 outdoor protective lights (OPLs) on its D9 Rate Schedule. Community Lighting also provides Commission-approved tariff service to municipalities for the operation of automated traffic signal (ATS) lights on its E2 Rate Schedule (Bellini, 7T 1712).

DTE Electric's proposed E1 Option I Rate reflects recovery of costs associated with the Company's ownership, maintenance and provision of energy to its portfolio of mercury vapor, high

pressure sodium, metal halide, and light emitting diode (LED) lighting.¹⁰⁴ Option II (closed to new customers since 2009) is for street lighting systems owned by municipalities, but maintained by the Company. Option III is where the municipality owns and maintains the system, and the Company provides only energy (Bellini, 7T 1712-1713). DTE Electric's proposed D9 Rate Schedule reflects recovery of costs associated with the Company's ownership, maintenance and provision of energy to its portfolio of approximately 23,000 commercial and more than 9,000 residential OPLs. DTE Electric's proposed E2 rate schedule reflects the recovery of costs for the production and distribution of energy for ATS lights owned and maintained by municipalities and other public authorities (Bellini, 7T 1714-1715).

Exhibit A-16, Schedule F3 shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the projected test year (Bellini, 7T 1726). The lighting rates approved in Case No. U-20561 reflect a monthly energy charge, both non-capacity and capacity energy, and a luminaire charge. DTE Electric does not propose to change the methodology for allocating production and distribution revenue requirements to the various lighting rate schedules (Bellini, 7T 1727-1728).

Mr. Bellini supported the proposed allocation of costs reflected in the various E1 Option Rate Schedule luminaire charges, testifying: "The methodology utilized in the lighting model to allocate each of the individual cost of service components discretely, rather than in total, more accurately reflects the cost to provide lighting service to underground and overhead assets as well as the various lighting technologies. The usage of the eight separate asset subaccounts for allocation of the capital-related costs results in more accurate rate setting based upon both how the lights are

¹⁰⁴ Mr. Bellini also discussed DTE Electric's efforts to control costs for maintaining E1 Option 1 overhead fed streetlighting (7T 1737-1740).

fed as well as the lighting technology, wattage and luminaire investment” (7T 1732). He also explained how E1 Option II and Option III charges were developed, and supported the Company’s proposed E1 rates as appropriately continuing the gradual move to rates that are entirely based on cost of service (Bellini, 7T 1732-1734). The Company’s proposed D9 rates similarly allocate costs and continue the gradual movement toward cost-based rates (Bellini, 7T 1735). Mr. Bellini also explained and supported Rate Schedule E2 charges (7T 1735-1736).

Mr. Bellini also explained the Company’s proposal to clarify the tariff language for E1 and D9 customers taking Dusk to Midnight service or Experimental Programmable Photocell service (7T 1736-1737).

Mr. Bellini also responded to MI-MAUI witness Bunch’s apparent misperceptions about expense allocation, and explained that his proposal to change the existing methodology of developing rates would have a significant financial impact on certain communities (7T 1747-1748).

H. Nuclear Surcharge

The nuclear surcharge recovers costs for Fermi 2 site security, radiation protection, nuclear decommissioning, and Low Level Radioactive Waste (LLRW) disposal. These activities are required for Fermi 2’s safe and secure operation. DTE Electric proposes to increase the nuclear surcharge only with respect to inflation for the Site Security and Radiation Protection portion of the surcharge. The Nuclear Decommissioning funding and LLRW disposal funding are unchanged. The resulting nuclear surcharge is \$39.1 million for the projected test period (Exhibit A-20, Schedule J1, page 1, line 5, column (b)), which is an increase of \$0.3 million from the currently-authorized nuclear surcharge. The Company’s proposed nuclear surcharge is reasonable and prudent, and therefore should be approved (Davis, 7T 2573-2574. See also Willis, 6T 921; Exhibit A-16, Schedule F6).

I. 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 to be set at the power supply rate less 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.¹⁰⁵ 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 as discussed elsewhere).

¹⁰⁵ 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."

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" 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. 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 2024.¹⁰⁶ 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 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, the Company highlighted that 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

Staff and certain Intervenors asserted various arguments regarding the Company's proposal to require future Rider 18 customers to take base inflow service on the Company's proposed D1.12 "Stable Bill Service Level" rate. The Company responds to the arguments collectively below, with further details in Mr. Foley's rebuttal testimony (6T 1203-1211).

¹⁰⁶ 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).

CEO witness Lucas proposed to reject the Company's proposal, claiming that a cost shift does not exist (8T 3600). To the contrary, DG customers reduce the amount they contribute to the distribution system by reducing the amount of energy they inflow from the Company (Foley, 6T 1177, 1204). Also, the majority of the Company's delivery costs are fixed, so there is generally no delivery cost impact (savings to DTE Electric or reduced costs that might help lower rates for customers) when a customer decreases the amount of energy they inflow from the Company (Exhibit A-45, Schedule JJ3). Therefore, DG customers are presently able to reduce the amount they contribute to the distribution system, without the Company being able to realize a similar amount of savings or reduce other customers' distribution rates.¹⁰⁷ This results in upward rate pressure (the same costs with lower inflowed energy) that, if not corrected, effectively shifts costs onto non-DG customers (Foley, 6T 1204-1205).

Staff proposed to reject the Company's proposal claiming that the Company has not substantiated that an intra-class subsidy driven by Rider 18 customers is greater than exists elsewhere (Krause, 8T 5506-5507). The Company agrees that intra-class subsidies exist elsewhere, but disagrees that this should be used to justify not correcting such a subsidy when it can be clearly identified and targeted. As discussed above, the Company has demonstrated clear cost shifting from DG customers to non-DG customers and it maintains that it is appropriate to eliminate this cost shift to promote the equitable recovery of costs (Foley, 6T 1206).

MSNC and Ann Arbor witnesses proposed to reject the Company's proposal claiming that it is anti-competitive and/or discriminatory. The Company disagrees because, as discussed above,

¹⁰⁷ Furthermore, DG customers introduce two-way power flows which presents a meaningfully different relationship between the Company and these customers as compared to the relationship between DTE Electric and its 2 million other full service customers that only receive power inflows. (See, by way of example and not limitation, 6T 1206) In effect, DTE Electric provides DG customers additional services by comparison to other customers. This provides yet another reason to eliminate the cost shifts caused by DG customers.

it has demonstrated cost shifting from DG to non-DG customers, thereby justifying the requirement that future DG customers take service on a rate that addresses the cost shift (Foley, 6T 1207-1208).

Staff (Krause, 8T 5506) and some Intervenors proposed to reject the Company's proposal claiming that it violates the Company's stated rate design principles of optionality and incrementalism. The Company disagrees with these characterizations because it takes multiple principles and considerations into account when developing and proposing new rates or rate design changes. None of these principles or considerations is used in isolation, and one or more may be prioritized depending on the specific rate design proposal. Here, the Company prioritized its cost-alignment principle due to an unjustified cost shift from DG to non-DG customers, as discussed above. Also, DG customers voluntarily choose to install their DG systems. The Company is proposing a reasonable and justified requirement for new customers installing a DG system so that other customers do not have to subsidize DG customers' choices (Foley, 6T 1123, 1208-1210).

MNSC (Jester, 8T 3857) proposed that the Company perform a separate COS study treating DG customers as a separate class to analyze the costs and revenues being driven by these customers. The Company disagrees with MNSC witness Jester's proposal. Nobody (including Mr. Jester) has recommended treating DG customers as a separate class, so it is unclear what the study's objective would be, or what parameters or assumptions might be used in performing such a study. The suggested study is also unnecessary because the Company already demonstrated a cost shift from DG to Non-DG customers, as discussed above. Therefore, it would be inappropriate and unnecessary to conduct the proposed study (Foley, 6T 1211-1212).

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).

Staff (Revere, 8T 5139) and CEO witness Lucas asserted that the Company's proposal to use average LMPs, calculated separately for each TOU pricing period, is inappropriate because such a calculation would consider LMPs during times when DG is unlikely to flow. The Company's original proposal was designed for ease of understanding and to align with MCL 460.1177(4)'s language; however, the Company would consider an alternative calculation that more precisely targets hours when outflow would occur. Witness Lucas' proposal (8T 3630, line 12) is an appropriate starting point, but if it were to be adopted, the Company recommends that a separate "Overnight Outflow Window" be established for hours not identified by witness Lucas as being likely outflow hours (6T 1213-1215). For example, if the Commission were to adopt Witness Lucas' suggestion of establishing a daytime summer outflow window of 7 AM to 6 PM (8T 3631), then it should also establish an overnight summer outflow window of 6 PM to 7 AM in order to compensate any outflow that occurs during this time. A similar approach could be used for non-summer months.

Staff (Krause, 8T 5509-5510 8-9) and GLREA witness Richter (8T 3174) suggested that the use of average LMPs to set outflow compensation is inappropriate given that LMPs cannot be known in advance, and therefore, customers cannot optimize their use of their DG systems. The Company agrees that the exact compensation that would be paid to DG customers for their outflow cannot be known in advance, but it disagrees that this should justify rejection of its proposals. Using average monthly LMPs, either calculated as the Company proposed originally or as indicated above based on witness Lucas' proposal (8T 3630, line 12), would have a smoothing effect on the per kWh compensation paid to DG customers. Thus, DG customers would potentially have a good idea

of what their likely compensation would be, so that they could optimize the use of their DG systems (Foley, 6T 1215-1217).

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 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).

3. Program Design And Additional Issues

Staff and certain Intervenors asserted various arguments regarding the design of the Company’s DG program. The Company responds to the arguments collectively below, with further details in Mr. Foley’s rebuttal testimony (6T 1225-1233).

MEIBC/EIB witness Sherman seemed to suggest that the Company would stop interconnecting DG systems once MCL 460.1173(3)’s category-specific reservations are met (0.5% for Category 1 systems; 0.25% for Category 2 systems; and 0.25% for Category 3 systems) (8T 4394-4395). To be clear, there are no limitations on the number of customers that can pursue DG installations, and the Company’s discovery responses highlighted that it does not limit the number of DG systems that can connect to its grid, nor is it proposing to do so here (Exhibit A-45, Schedules JJ4 and JJ5). Once the category-specific reservations are met, the Company would continue to

interconnect DG systems under, for example, Rider 14 assuming that Rider 14's basic structure and compensation model do not change. The Company would support updating Rider 14's eligibility requirements to match the current Rider 18 eligibility requirements ("This Rider can be attached to any metered tariff, excluding riders, unless noted on the applicable metered tariff") to broadly ensure that customers are able to interconnect their DG systems in the future (Foley, 6T 1225-1228).

Staff recommended that the Company not enforce MCL 460.1173(3)'s category-specific limits (Mathews, 8T 5387). The Company disagrees because the category-specific reservations that are defined in MCL 460.1173(3) are unambiguous, so they must be followed (Foley, 6T 1228-1229).¹⁰⁸

The Company also disagrees with Intervenor suggestions 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. As indicated above, tariffs (specifically Rider 14 and Rider 5), that will allow DG customers to interconnect their systems once MCL 460.1173(3)'s category-specific reservations are met already exist. 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

¹⁰⁸ Statutes must be applied as written. *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); *Amb's v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

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.)

CEO witness Lucas proposed that Rider 14 outflow compensation be set at 12.3 cents/kWh (8T 3639-3645). The Company disagrees because witness Lucas’ calculations are based solely on the characteristics of rooftop solar, while Rider 14 is not solely available to solar systems. It is available to “reciprocating engine generator sets, small turbine-generators, fuel cells, regenerative dynamometers and renewable resources.” It would not be appropriate to apply the compensation calculated for one technology to a host of other technologies that have potentially different characteristics and outflow profiles. Witness Lucas’ analysis also results in a value well above the fair value of outflow. The Company maintains that outflow compensation should be based on market-based LMPs, as Rider 14 is presently. Any deviation from the current structure would potentially introduce or exacerbate cost shifts onto non-DG customers (Foley, 8T 1231-1233).

Therefore, the Company’s proposed changes to Rider 18 should be approved, and any alternative recommendations should be rejected or modified as discussed above.

Staff proposed to allow customers with DG to take service on rate schedule D1.8 Dynamic Peak Pricing, yet acknowledged that “the rate is considered to be a demand response rate, with pricing set to encourage certain behaviors” (Revere, 8T 5141). The Company disagrees because demand response products are designed to encourage customers to substantially reduce usage during specific system conditions. The D1.8 rate provides this encouragement with a significant increase in the power supply rate, from about 16 cents/kWh during the normal on-peak to 95 cents/kWh during critical peak events. Since rate schedule D1.8 is intended as a narrow demand response tool, it excludes all separately-metered supplemental services (not just DG). Paying

outflow compensation using a rate that was designed as a demand response tool would be inappropriate because it would vastly overcompensate certain DG customers at the expense of all other customers. Under Staff's proposal, the outflow credit during a D1.8 critical peak event would be approximately 10 times today's D1 outflow credit. This has no plausible avoided cost basis. Generally speaking, this highlights the pitfall of linking distributed generation outflow credits with retail rate schedules which vary broadly in design and intent. The IT costs of such a change would also be material. Therefore, Staff's proposal should not be adopted (Willis, 6T 972-974).

J. Retail Access Service Rider (RASR)

The Company proposes three changes to the current RASR. First, update the Real Power Loss Factors to reflect the results of the new line loss study, and from quarterly to monthly loss factors to align with the new line loss study.¹⁰⁹ The Company would make these updates effective within 90 days following an order in this case (Willis, 6T 961-963; Exhibit A-28, Schedule R1 shows the Real Power Loss Factor results).

The second change concerns the RAS enrollment process. Currently, only the termination request and timeline are included in the RASR. The Company requests to add the enrollment request and timeline to the RASR. Finally, the Company proposes to modify the termination language to be consistent with the enrollment language (Willis, 6T 961, 963-964; Exhibit A-16, Schedule F8, section E reflects the proposed changes to the RASR).

Energy Michigan witness Zakem proposed changes in response to the Company's proposed insertions regarding the timing of "enrollment" and "enrollment date" (8T 4492). The Company

¹⁰⁹ Real Power Loss Factors are used for submitting Retail Access Service (RAS) usage to MISO when the Company is the Meter Data Management Agent (MDMA) for the Marketer (Willis, 6T 962-963).

recommends building on witness Zakem’s proposed language by capitalizing the defined terms and referencing Case No. U-15801 (as set forth at Willis, 6T 1002-1003).

K. Other Proposals

1. Rider 3

Bloom witness Morse characterized 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). These characterizations merit no weight because witness Morse offered no quantitative or cost-of-service support. One would also expect that customers exploring onsite generation would consider matters beyond just the Company’s rates, such as the costs of the generating asset (Willis, 6T 981).

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 disagrees with all of the recommendations as discussed below, and further detailed in Mr. Willis’ rebuttal testimony (6T 972-986).

The first recommendation is that the Commission require the Company to identify and categorize all forced outages by Rider 3 customers as either: (1) customer-initiated, or (2) non-customer initiated. This recommendation should be rejected because it would harm customer privacy. Customers have no obligation to provide a reason for their outages. The Company would have to compel customers to provide their generator performance information, including potentially sensitive competitive/business data. The proposed categorization is also unnecessary because total service outages for customers with Rider 3 averaged 33 per year over the last five years. Over the same period, the Company averaged approximately 31 Rider 3 customers. Therefore, on average

and across all causes, there was approximately one service outage per Rider 3 customer per year ($33/31 = 1.06$). (Willis, 6T 983; Exhibit BE-7, p 4).

The second recommendation is that the Commission require the Company to track all non-customer-initiated outages experienced by Rider 3 customers, and perform a study for the purpose of: (1) identifying the cause of non-customer-initiated outages experienced by Rider 3 customers; (2) improving impaired distribution grid conditions that may be contributing to the outages; and (3) reducing and/or eliminating such outages in the future. This recommendation should be rejected based on the privacy concerns and the lack of justification as discussed above. Such a study would also require extensive manual review of records and outreach to customers to search for information that might not be available. Unless customers were compelled to disclose information (which the Company does not support), such a study would be based on deeply incomplete data (Willis, 6T 983-984).

The third recommendation is that, pending the results of the study discussed above, the Commission suspend the assessment of Rider 3 distribution charges. The Company strongly recommends that the Commission reject this proposal because arbitrarily suspending approved and cost-based rates would violate MCL 460.11 (requiring cost-based rates), since the distribution revenue allocated to Rider 3 customers would be collected from other customers. Bloom essentially proposes that Rider 3 customers would receive free service subsidized by other customers, which would effectively act as a subsidy for Bloom's product. Also, as discussed above, there is no justification for the proposed study and the Company might not even be able to complete such a study (Willis, 6T 984-985).

The fourth recommendation is that the Commission disallow the Company from adjusting a Rider 3 customer's contract capacity or billing demand based on non-customer-initiated forced

outages. The Company recommends that the Commission make no changes to the Rider 3 tariff language because, as discussed above, the Company does not have insight into when, how, or even if Rider 3 generators are in a forced outage state unless customers proactively share that information. There are also no energy-based billing determinants generated when there is a grid outage and no service. The customer's contract capacity and billing demand will not change when there is a service outage. These same reasons apply to the further recommendation to extend the proposed adjustment to the four hours following a grid outage, which also should be rejected because there is no cost basis for such a recommendation. Indeed, the suggested justification is to benefit Bloom's technology, but customers have multiple options for on-site generation if they do not consider Bloom's technology to be appropriate for their energy needs (Willis, 6T 985-986).

Bloom witness Jester further proposed that the Commission amend Rider 3 to provide the following additional method to calculate a customer's contract capacity: "For customers with self-generation comprised of modules, each with an average availability of 90% or more, standby contract capacity is not required to be set at a level sufficient to meet the customer's aggregate standby load, and instead may be set to a level sufficient to meet the standby needs of one or more of the system's modules as determined by the customer" (8T 4557). This proposal should be rejected as unsupported (based on cost of service, Company operations, or otherwise) and contrary to ratemaking principles. The position that "modularity" should give a Rider 3 customer the ability to override the currently-approved methods for determining contract capacity appears designed to simply improve the economics of Bloom's products at the expense of the Company's other customers. Customers with a "modular" (Bloom) system would have the unique ability to determine how they are charged (and be charged less) for the exact same service as similarly-situated customers by essentially being able to reduce their generation reservation fees and distribution

charges to whatever the customer deemed appropriate - presumably based on one "module" for the lowest costs (Willis, 6T 987-988).

Bloom witness Jester further asserted that "[s]imilar to the use of a system's FOM [forced outage rate] in calculating a standby customer's reservation fee, a standby customer's distribution-related demand charges (a.k.a. demand delivery charges under Rider 3) should be pro-rated to reflect the customer's partial and infrequent use of the distribution grid" (8T 4548). He reasoned that "[i]n light of the high reliability of many onsite generators, and Bloom Energy Systems in particular," customers with these systems should receive preferential treatment compared to the distribution demand charges assessed to all secondary, primary, subtransmission and transmission customers on demand-based rates (Jester, 8T 4548). He further proposed a complex construct to implement a re-designed "preferential" Rider 3 rate (Jester, 8T 4551).

The Company disagrees because witness Jester's proposal would functionally eliminate standby distribution charges for Rider 3 customers and shift the costs to other customers. The proposal should be rejected because: (1) the distribution system is designed to serve customer peaks whenever they occur, so neither the forced outage rate of a generator nor the timing of those outages is relevant to how distribution charges are designed;¹¹⁰ (2) witness Jester's attempted analogy to the treatment of power supply capacity for resource adequacy purposes is not germane to distribution system cost recovery and rate design; (3) the Company's distribution rates are designed to recover the full costs of the system; they are not, for any customer, designed on marginal costs as witness Jester proposes, and they are designed on the averages, contrary to witness Jester's

¹¹⁰ The Company's proposed Rider 3 generation reservation charges are designed to reflect the forced outage rate of the best performing generators, consistent with past Commission Orders and approved rate design (Willis, 6T 988; Exhibit A-16, Schedule F3, p 42, column (e), line 15).

customer-specific “additional demand charge”; and (4) the Commission declined to adopt witness Jester’s similar proposal in Case No. U-20162 (Willis, 6T 989-993).

Witness Jester also suggested that the Commission require the Company to set an on-peak daily power supply charge based on a proration of the full service D11 monthly power supply demand charge, citing the Orders in Case Nos. U-18255 and U-20162 (8T 4554). There is nothing to do here because the Company designed its Rider 3 power supply rates consistent with the approved rate design in Case No. U-20561, which was consistent with the cases cited by Mr. Jester (Willis, 6T 993-994).

2. Rider 17

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 updated Rider 17 would be appropriate in the Company’s Section 61 proceedings (Crozier, 7T 2395-2396). (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.))

3. Power Factor Clause

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 Company agrees 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. 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).

4. Community Solar

Staff (Baldwin, 8T 5446-5455) and DAAO witness Donovan (*e.g.*, 8T 4200) made proposals indicating similar goals, but very different ideas about how a community solar project might be designed. 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, with the potential for a proposal in the Company's next rate case (Crozier, 7T 2384-2387). (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.))

5. Earnings Sharing Mechanism (ESM)

In connection with his comments about projected test years (see section V above), ABATE witness Dauphinais further suggested that an asymmetrical earnings sharing mechanism (ESM) should be imposed on the Company in this case (8T 2902-2905). The suggestion should be rejected as premature (at best) and because there is not enough time to properly consider such a mechanism following ABATE's filing of intervenor testimony. If an ESM is to be considered, then it should be evaluated as part of a broader performance-based ratemaking (PBR) conversation. A larger discussion of PBR might include topics such as ABATE's ESM proposal and other metrics, incentives, and capital trackers as described by the Company in its Distribution Plan, Exhibit A-23, Schedule M1 (Crozier, 7T 2387-2388).

XII. 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, and this Initial Brief (including Attachments A and B) approving rates that will recover the Company’s revenue deficiency of approximately \$367.9 million, based on a November 1, 2022 through October 31, 2023 projected test year;
- 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, and this Initial Brief (including 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-20162 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 and this Initial Brief (including 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: July 26, 2022

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DTE Electric Company
 Computation of Revenue Deficiency
 Projected 12 Month Period Ending October 31, 2023
 (\$000)

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 Initial Brief
 Attachment A
 Page 1 of 4

Line No.	(a) Description	(a) Source	(b) U-20836 Filed	(c) Adjustments	(d) U-20836 Initial Brief Position
1	Rate Base	Attach A, Page 2	\$ 21,267,944	\$ (25,162)	\$ 21,242,782
2	Adjusted Net Operating Income	Attach A, Page 3	899,199	13,624	912,824
3	Rate of Return	Attach A, Page 4	5.56%	0.00%	5.56%
4	Income Requirements		1,181,647	(1,398)	1,180,249
5	Income Deficiency (Sufficiency)		282,448	(15,022)	267,425
6	Revenue Conversion Factor	Exh, A-13, Sch. C2	1.3496	-	1.3496
7	Revenue Deficiency (Sufficiency)		\$ 381,201	\$ (20,275)	\$ 360,926
6	Tree Trim Surge	Exh, A-11, Sch. A1	7,021	0	7,021
7	Revenue Deficiency (Sufficiency)		\$ 388,222	\$ (20,275)	\$ 367,947

DTE Electric Company
Rate Base - Average Net Plant
For the 12 Month Average Period Ending 10/31/2023
(\$000)

MPSC Case No. U-20836
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Attachment A
Page 2 of 4

Line No.	(a) Description	(b) U-20836 Filed	(c) Adjustments	(d) U-20836 Initial Brief Position
1	Plant in Service	\$ 25,100,823	\$ (18,730) (1)	\$ 25,082,094
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	26,788,306	(18,730)	26,769,577
5				
6	Less: Depreciation Reserve	6,930,603	(1,622) (2)	6,928,981
7				
8	Net Utility Plant	19,857,703	(17,107)	19,840,596
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	20,029,597	(17,107)	20,012,490
14				
15	Less: Capital Lease Obligations	19,036		19,036
16				
17	Net Plant	20,010,561	(17,107)	19,993,454
18				
19	Allowance for Working Capital	1,257,383	(8,055) (3)	1,249,328
20				
21				
22	Rate Base	<u>\$ 21,267,944</u>	<u>\$ (25,162)</u>	<u>\$ 21,242,782</u>

(1) (2) Capital adjustments to Plant and Depreciation Reserve:

	Net Cap Ex	Plant Adj. (1)	Accum. Depr. (2)	
Customer Svc - Integrate DTE Insight	\$ -	\$ -	\$ -	7T 2137
Engineering Transformer Database	(370)	(185)	(19)	7T 2137
Decommission DOBW-move	(370)	(185)	(19)	7T 2137
Documentum (EDM) Modernization	(370)	(185)	(19)	7T 2137
IT - Inbound Email Threat Analytics	(400)	(200)	(20)	7T 2137
Headquarters Energy Center	(700)	(700)	(97)	7T 2784
Enterprise Automation	(596)	(596)	(219)	7T 2784
Wixom Pole Yard	(4,500)	(3,084)	(170)	7T 2730
ACPP/Time of Use	(13,194)	(11,369)	(676)	7T 2257, 7T 2269
DERMS - Duplicate Project	(2,500)	(2,227)	(385)	8T 5216, 7T 2139
	<u>\$ (23,000)</u>	<u>\$ (18,730)</u>	<u>\$ (1,622)</u>	

(3) Working Capital \$ (8,055) 8T 5060, Company Brief section VI(A)

DTE Electric Company
Adjusted Net Operating Income
Projected 12 Month Period Ending October 31, 2023
(\$000)

MPSC Case No. U-20836
Initial Brief
Attachment A
Page 3 of 4

Line No.	(a) Description	(b) U-20836 Filed	(c) Adjustments	(d) U-20836 Initial Brief Position
	<u>Net Operating Income</u>			
	<u>Operating Revenues</u>			
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	<u>3,720,783</u>	<u>0</u>	<u>3,720,783</u>
5				
6	<u>Operating Expenses</u>			
7	Operations and Maintenance Expenses	1,280,715	(16,720) (1)	1,263,995
8	Depreciation and Amortization	1,087,914	(1,798) (2)	1,086,116
9	Property and Other Taxes	356,311		356,311
10	Total Operating Expenses	<u>2,724,941</u>	<u>(18,518)</u>	<u>2,706,423</u>
11				
12	Operating Income	995,842	18,518	1,014,360
13				
14	<u>Other Operating Income Adjustments</u>			
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	<u>40,993</u>	<u>0</u>	<u>40,993</u>
19				
20	PreTax Net Operating Income	<u>\$ 1,036,835</u>	<u>\$ 18,518</u>	<u>\$ 1,055,353</u>
21				
22	Federal Income Tax	83,250	3,744	86,994
23	State and Local Income Taxes	54,386	1,150	55,536
24				
25	Net Operating Income	<u>\$ 899,199</u>	<u>\$ 13,624</u>	<u>\$ 912,824</u>
	<u>(1) O&M</u>			
	- Tree Trim O&M - Surge Savings		\$ (4,200)	7T 2334
	- Customer Service Representatives		(950)	7T 1644
	- Merchant Fees		(2,970)	8T 5265 (3)
	- Pension Expense		(8,600)	7T 1882
			<u>\$ (16,720)</u>	
	<u>(2) Depreciation and Amortization</u>			
	Customer Service - Integrate DTE Insight		\$ -	7T 2137
	DO Eq Engineering Transformer Database		(37)	7T 2137
	Decommission DOBW-move to Data Lake		(37)	7T 2137
	Documentum (EDM) Modernization		(37)	7T 2137
	IT - Inbound Email Threat Analytics		(40)	7T 2137
	Headquarters Energy Center		(53)	7T 2784
	Enterprise Automation		(119)	7T 2784
	Wixom Pole Yard		(234)	7T 2730
	ACPP/Time of Use		(796)	7T 2257, 7T 2269
	DERMS - Duplicate Project		(445)	8T 5216, 7T 2139
			<u>\$ (1,798)</u>	

(3) Concession agreed to in Company Brief section VIII(H)(6)(b)

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending October 31, 2023
Based on Average Rate Base
(\$000)

MPSC Case No. U-20836
Initial Brief
Attachment A
Page 4 of 4

Line No.	Description	Amount (\$000)	Percent	Cost %	Weighted Cost % (1)	Weighted Cost %			
<u>U-20836 Filed (Test Period Average Basis)</u>									
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>U-20836 Initial Brief (Test Period Average Basis)</u>									
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%

DTE Electric Company
Revenue Requirement Adjustments to Company's Filing
Projected 12 Month Period Ending October 31, 2023
(\$000)

Line No.	(a) Description	(b) Source	(c) Revenue Deficiency (Pre Tax Amts)
1	Company's Filed Position	Exhibit A-11 Sch A-1	\$ 388,222
2			
3	<u>Adjustments to Revenue Deficiency:</u>		
4			
5			
6	Rate Base (1)		
7	- Net Rate Base, Increase/(Decrease)	Attachment A page 2	(1,756)
8			
9			(25,162)
10	Operations and Maintenance Expenses		
11	- Tree Trim O&M - Surge Savings	Attachment A page 3	(4,200)
12	- Customer Service Representatives	Attachment A page 3	(950)
13	- Merchant Fees	Attachment A page 3	(2,970)
14	- Pension Expense	Attachment A page 3	(8,600)
15			
16			
17			
18			
19			
20			
21	Depreciation and Amortization		
22	- Depreciation Expense, Increase/(Decrease)	Attachment A page 3	(1,798)
23			
24			
25	Total Adjustments to Company's Initial Revenue Deficiency	Line 6 through Line 26	\$ (20,274)
26			
27	Company's Brief Position	Line 1 + Line 27	\$ 367,948

(1) 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)

CAITLIN D. MYERS states that on July 26, 2022, she served a copy of DTE Electric Company's Initial Brief in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

CAITLIN D. MYERS

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