STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR 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 of supply of electric energy, and for miscellaneous accounting authority.	)))))	Case No. U-20836

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on September 19, 2022.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before October 5, 2022, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before October 17, 2022.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by: Sharon L. Feldman
DN: CN = Sharon L. Feldman email = feldmans@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2022.09.19 14:34:31 -04'00'

Sharon L. Feldman
Administrative Law Judge

September 19, 2022
Lansing, Michigan

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of DTE Electric	)	
Company for authority to increase its rates,	)	
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the distribution of supply of electric energy,	)	
and for miscellaneous accounting authority.	)	

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On January 21, 2022, DTE Electric Company (DTE) filed a rate application requesting a $388 million revenue increase, and other relief. The rates requested in the application are based on a November 1, 2022 through October 31, 2023 projected test year. The company's application was accompanied by the testimony and exhibits of 31 witnesses. The most recent rate case order for DTE was issued by the Commission on May 8, 2020 in Case No. U-20561.

Staff, DTE, and potential intervenors attended the February 18, 2022, prehearing conference. Intervention was granted to 29 parties, some of whom participated collectively as noted: Attorney General Dana Nessel (Attorney General); Energy Michigan, Inc. (Energy Michigan); Michigan Energy Innovation Business Council (MEIBC) and Institute for Energy Innovation (IEI) (collectively, MEIBC/IEI); ChargePoint, Inc. (ChargePoint); Bloom Energy Corp. (Bloom); Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens

Utility Board of Michigan (CUB) (collectively MNSC); Association of Businesses Advocating Tariff Equity (ABATE); The Kroger Company (Kroger); Gerdau MacSteel, Inc. (Gerdau); Local 223, Utility Workers Union of America (UWUA), AFL-CIO (Local 223); Environmental Law & Policy Center, Ecology Center, and Vote Solar (collectively, the Clean Energy Organizations or CEO); Michigan Municipal Association for Utility Issues (MI MAUI); the City of Ann Arbor (Ann Arbor); Walmart, Inc. (Walmart); Great Lakes Renewable Energy Association (GLREA); Residential Customer Group (RCG); Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy Organization or DAAO); Zeco Systems, Inc. (Zeco); EVgo Services, LLC (EVgo); and the Michigan Cable Telecommunications Association (MCTA). The parties agreed to a schedule meeting the time limits of MCL 460.6a.

DTE's application included a proposed protective order. Following a motion hearing on February 25, the ALJ issued a ruling and a modified protective order on March 1, 2022. DTE subsequently appealed the ruling. Also related to the protective order, on May 11, 2022, DTE filed a motion to limit discovery of its capacity demonstration filing in Case No. U-21099. Following a May 26, 2022 motion hearing, the ALJ issued a ruling on May 27, 2022, modifying the protective order. MI MAUI also filed a motion regarding the designation of certain material as confidential under the protective order on May 23, 2022, but subsequently withdrew the motion on June 1, 2022, after resolving the issue with DTE.

On February 18, 2022, the International Transmission Company (ITC) filed a late petition to intervene. With no party objecting, the ALJ issued a ruling on February 24, 2022 granting the petition. The RCG also filed a motion on April 8, 2022, seeking to consolidate this case with Case No. U-21087, but decided not to request a hearing on the motion.

By the May 19, 2022 filing deadline, Staff and the following intervenors filed direct testimony and exhibits: the Attorney General; ABATE; MNSC; the CEO; the DAAO; GLREA; Kroger; Walmart; Local 223; MI MAUI; Ann Arbor; Gerdau; MEIBC; Energy Michigan; Bloom; ChargePoint; EVgo; and ITC. By the June 13, 2022 filing deadline, DTE, Staff, the Attorney General, ABATE, MNSC, the DAAO, GLREA, Kroger, Ann Arbor, Energy Michigan, ChargePoint, EVgo, and Zeco filed rebuttal testimony.

At the evidentiary hearings held on June 29, 30, and 31, and July 5 and 7, 2022, 7 witnesses appeared for cross-examination, while the testimony of the remaining 97 witnesses was bound into the record by agreement of the parties without the need for them to appear. On July 20, 2022, DTE filed proposed transcript corrections. The parties filed briefs and reply briefs in accordance with the established schedule. DTE, Staff, and all intervenors who filed testimony in this case filed initial briefs on July 26, 2022.[1] These parties also filed reply briefs on August 16, 2022, with the exception of Walmart and Gerdau.

As discussed in section II below, the record includes testimony from a total of 104 witnesses.

[1] DTE, Staff, the Attorney General, ABATE, MNSC, DAAO, CEO, Zeco, GLREA, MI MAUI and Ann Arbor, Local 223, ITC, Gerdau, Kroger, Walmart, MEIBC and IEI, Energy Michigan, ChargePoint, Bloom, and EVgo filed briefs.

II.

OVERVIEW OF THE RECORD

The evidentiary record in this proceeding is contained in eight public transcript volumes plus a confidential transcript and 776 exhibits, several of which also have a confidential version.[2] The following discussion is not intended to catalog every conclusion reached or recommendation made by each witness, but to give a general overview of the principal issues addressed by each witness.

A. DTE Electric

DTE presented testimony of 31 witnesses and Exhibits A-1 through A-6 and A-11 through A-52.

Adella F. Crozier is Director within the Regulatory Affairs department of DTE Energy Corporate Services, LLC.[3] She presented an overview of the company's rate case filing, including discussions of the key drivers of the requested revenue deficiency of $388 million, the methodology DTE used to develop the projections in this case, issues raised by the Commission's last rate case order, and other issues she considered noteworthy. Ms. Crozier also provided an introduction of the other witnesses providing direct testimony in support of the company's application. In her rebuttal testimony, Ms. Crozier addressed a wide variety of issues: Staff witness recommendations regarding the treatment of removal costs for associated with the

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[2] Volume 1 is the transcript of the prehearing conference; volume 2 is the transcript of a motion hearing; volume 3 is the transcript of a status conference; volumes 4-6 contain the testimony of witnesses for DTE who were cross-examined; volume 7 contains the testimony of witnesses for DTE who were not cross-examined; volume 8 contains the Staff and intervenor testimony. All official exhibits were to be filed with the designation "official exhibit."

[3] Ms. Crozier's testimony is transcribed at 7 Tr 2336-2396; her qualifications are presented at 7 Tr 2337-2339.

retirement of generating plant assets, Staff and DAAO witness recommendations regarding community solar, ABATE witness recommendations regarding use of a projected test year, earnings sharing, O&M expenses generally and reliance on the used and useful principle for distribution system assets, Kroger witness recommendations regarding the treatment of outage credits, Energy Michigan witness recommendations regarding the capacity charge, GLREA witness recommendations regarding Rider 17 and renewable energy credit pricing, MNSC witness recommendations regarding the development of a data base containing performance and operational measures of other utilities, and Staff witness recommendations regarding shared assets.

Timothy J. Lepczyk is Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and DTE. He testified in support of DTE's recommended capital structure and projected cost of long-term and short-term debt. Mr. Lepcyzk also recommended debt and equity financing for future tree trimming expenditures. In rebuttal, he addressed an alternate capital structure proposal presented by a witness for MNSC and financing of tree trimming expenditures.[4]

Shawn D. Burgdorf is the Manager of the Power Supply Strategy & Modeling team in DTE's Generation Optimization department.[5] He testified to the company's projected wholesale market energy sales revenue, including a projection of the company's capacity-related PSCR costs, and provided an overview of MISO's resource adequacy requirements and the projected capacity market. He also presented an

[4] Mr. Lepczyk's testimony is transcribed at 7 Tr 1278-1299; his qualifications are presented at 7 Tr 1279-1281.
[5] Mr. Burgdorf's testimony is transcribed at 4 Tr 109-213; his qualifications are set forth at 4 Tr 114-116.

analysis of potential retirement dates for the Belle River plant. Mr. Burgdorf's rebuttal testimony further addressed projected MISO market capacity costs in the context of the analysis of Belle River and defended the company's State Reliability Mechanism (SRM) capacity charge. He was also cross-examined on his testimony.

Sharon G. Pfeuffer is the Vice President of Distributions Operations Engineering and Construction for DTE Energy Corporate Services, LLC.[6] She testified in support of the company's historical and projected distribution system capital and O&M spending. Ms. Pfeuffer also presented rebuttal testimony in support of these expenditures and was cross-examined on her testimony. Her rebuttal responded to recommended reductions in projected capital and O&M expenses, and she was cross-examined on her testimony.

Aaron Willis is Manager for Regulatory Economics at DTE Corporate Services, LLC.[7] He testified in support of the company's rate design, calculation of the PSCR base factor, and the nuclear surcharge. He provided information regarding the company's current contribution in aid of construction (CAIC) policy. He also recommended changes to the company's Retail Access Service Rider (RASR) and other tariff changes. Mr. Willis's rebuttal testimony responded to rate design and tariff recommendations of Staff and intervenor witnesses, the revenue calculation, and recommendations for future analysis. He was cross-examined on his testimony.

Habeeb J. Maroun is a Principal Financial Analyst in DTE Energy's Revenue Requirements department, a part of its Regulatory Affairs organization.[8] He presented DTE's cost of service study, included in Exhibit A-16, including the development of the

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[6] Ms. Pfeuffer's testimony is transcribed at 4 Tr 215-612; her qualifications are set forth at 4 Tr 224-227.
[7] Mr. Willis's testimony is transcribed at 6 Tr 910-1019; his qualifications are presented at 6 Tr 915-916.
[8] Mr. Maroun's testimony is transcribed at 6 Tr 1020-1115; his qualifications are presented at 6 Tr 1025-1026.

capacity charge revenue requirement by customer class. His rebuttal testimony addressed the allocation of production costs, the allocation of uncollectible expense, the capacity charge calculation, alternative streetlighting cost allocation issues, and Advanced Metering Infrastructure (AMI) cost allocation. He was also cross-examined on his testimony.

Neal T. Foley is Director of Regulatory Affairs for DTE Energy Corporate Services, LLC.[9] He testified in support of the company's overall approach to rate design, the company's plans regarding the implementation of time-of-use (TOU) rates, the preliminary results of the company's Advanced Customer Pricing Pilot (ACPP), its proposed voluntary residential demand-based tariff, and the company's distributed generation (DG) program rate design. Mr. Foley's rebuttal testimony responded to recommendations by Staff and intervenors regarding residential rate design and the DG program. He was also cross-examined on his testimony.

Justin L. Morren is Energy Supply Gas Plant Director for DTE.[10] He testified in support of the company's projected generation capital and O&M expense, including a discussion of environmental compliance requirements, Tier 2 coal plant retirements and associated costs, and the company's plan to retire Belle River in 2028. He also discussed forecast changes in company power plant capacity ratings and unit availability, as well as emerging technologies the company is incorporating in its generation portfolio through planned pilot projects. His rebuttal responded to

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[9] Mr. Foley's testimony is transcribed at 6 Tr 1116-1262; his qualifications are presented at 6 Tr 1120-1121.
[10] Mr. Morren's testimony is transcribed at 5 Tr 621-796.

recommended reductions in the company's capital and O&M expense projections, and he was cross-examined on his testimony.

Tamara D. Johnson is Director of the Revenue Management and Protection organization within DTE Energy.[11] She testified in support of the company's low-income assistance programs, including proposed tariff changes, and in support of its projected uncollectible account expense. Her rebuttal testimony addressed uncollectible accounts expense, the projected Residential Income Assistance (RIA) customer count and corresponding sales revenue, programmatic details regarding the RIA and Low-Income Assistance (LIA) tariffs, and deposit collection expense. She was also cross-examined on her testimony.

Bente Villadsen is a Principal with the consulting firm The Brattle Group. Dr. Villadsen presented an analysis of the cost of equity that should be used in the revenue requirements calculation and a recommendation that the Commission should authorize a return on equity of 10.25%. She also presented rebuttal testimony evaluating intervenor witness recommendations regarding the cost of equity and responding to their criticisms of her analysis.[12]

Maheen Asghar is a Principal Financial Analyst in Regulatory Economics for DTE Energy Services, LLC. She presented the allocation schedules used in the company's cost of service study (COSS), explaining certain historical data and forecasts underlying the schedules as well as the company's new line loss study. In her rebuttal testimony, she objected to the alternate allocation methodology for secondary voltage distribution

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[11] Ms. Johnson's testimony is transcribed at 5 Tr 798-900; her qualifications are presented at 5 Tr 802-803.

[12] Dr. Villadsen's testimony is transcribed at 7 Tr 1303-1445; her qualifications are presented at 7 Tr 1305-1306 and 1357-1376.

recommended by a witness for the Attorney General and she addressed a recommended revision to the line loss study recommended by a witness for ABATE.[13]

Sherri L. Wisniewski is Director of Tax Operations for DTE Energy. She testified to support DTE's projected test year federal, state, and local income tax, property tax, and other general taxes.[14]

Morgan Elliott Andahazy is Director of the Advanced Distribution Management System (ADMS) for DTE. She testified in support of the company's historical and projected distribution operations capital and O&M expense, focusing on the ADMS implementation as well as its new Electric System Operations Center (ESOC) and planned Alternate System Operations Center (ASOC).[15] In her rebuttal, Ms. Elliott Andahazy disputed recommended reductions to the company's projections made by witnesses for Staff and the Attorney General.

Joseph E. Robinson is Director of Central Engineering Distribution for DTE. He explained the analysis underlying the company's line loss study and the results of that study.[16] He explained DTE's proposed clarifications to the company's tariff provisions regarding service connections, and discussed the benefits of new customer connections in support of the company's current CAIC policy. Mr. Robinson addressed the company's use of AMI data to address high and low voltage cases to address customer concerns. He also explained the company's recent hosting capacity analysis (HCA).

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[13] Ms. Asghar's testimony is transcribed at 7 Tr 1448-1465; her qualifications are presented at 7 Tr 1449-1450.
[14] Ms. Wisniewski's testimony is transcribed at 7 Tr 1468-1483; her qualifications are presented at 7 T 1469-1470.
[15] Ms. Elliot Andahazy's testimony is transcribed at 7 Tr 1532-1552; her qualifications are presented at 7 Tr 1487-1489.
[16] Mr. Robinson's testimony is transcribed at 7 Tr 1554-1582; his qualifications are set presented at 7 Tr 1555-1557.

Robert J. Lee is Manager of Environmental Management and Safety for DTE Energy Corporate Services, LLC, as well as Manager of Environmental Strategy for DTE.[17] He testified to the company's obligations under the Steam Electric Effluent Limitation Guidelines (ELG) and the Coal Combustion Residuals (CCR) Rule, including its historic and projected costs of compliance for its coal-fired power plants.

Thac K. Nguyen is the Manager of Residential Programs and Pilots in the Energy Waste Reduction (EWR) group for DTE.[18] He testified to explain the DTE Insight program, a component of DTE's Demand Response (DR) program, and to support the associated costs.

Jason E. Sparks is the Director of Customer Service Operations for DTE Energy Corporate Services, LLC.[19] He testified in support of the company's projected O&M expenses for the Customer Service organization, including a discussion of inflation and performance improvements. He also specifically addressed the deferred costs associated with the company's ACPP and TOU implementation. Mr. Sparks' rebuttal testimony addressed a reduction to the company's corporate services O&M expense recommended by a witness for the Attorney General as well as a statement regarding customer satisfaction made by a witness for Staff.

Keegan O. Farrell is Manager of Demand Response for DTE. He testified in support of DTE's proposed DR programs and current and proposed DR pilots, including the company's projected DR capital costs. He also discussed the company's proposed

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[17] Mr. Lee's testimony is transcribed at 7 Tr 1585-1598; his qualifications are set forth at 7 Tr 1586-1587.
[18] Mr. Nguyen's testimony is transcribed at 7 Tr 1601-1611; his qualifications are presented at 7 Tr 1601-1603.
[19] Mr. Sparks' testimony is transcribed at 7 Tr 1616-1647; his qualifications are presented at 7 Tr 1614-1615.

changes to its DR tariff language and non-interruption penalty, and the company's proposed allocation of the revenue from non-interruption penalties.[20] Mr. Farrell's rebuttal addressed Staff recommendations to disapprove funding for the residential generator pilot and demand response battery pilot.

Robert A. Bellini is Manager of Community Lighting for DTE. He testified in support of the company's historical and projected capital and O&M expenses for its community lighting program.[21] He testified to the energy forecast for the outdoor lighting rates, and the proposed rate design. He also recommended tariff changes for the lighting program, and explained the company's plans to reduce maintenance costs for overhead lights and promote efficiency. In rebuttal, he addressed programmatic and expense-related recommendations made by witnesses for Staff, MI MAUI and Ann Arbor.

Michael S. Cooper is Director of Compensation, Benefits & Wellness for DTE Energy Corporate Services LLC. He testified to support recovery of the company's employee compensation and benefit expenses, including post-retirement benefit expenses as well as the company's incentive compensation plans.[22] His rebuttal testimony addressed recommendations made by Staff and intervenor witnesses to exclude or limit the company's recovery of incentive compensation, recommendations regarding the level of health care and pension expense made by the Attorney General, and an alternative labor-cost projection recommended by a witness for ABATE.

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[20] Mr. Farrell's testimony is transcribed at 7 Tr 1649-1704; his qualifications are presented at 7 Tr 1650-1652.
[21] Mr. Bellini's testimony is transcribed at 7 Tr 1707-1776; his qualifications are presented at 7 Tr 1708-1709.
[22] Mr. Cooper's testimony is transcribed at 7 Tr 1779-1885; his qualifications are presented at 7 Tr 1780-1781.

Phillip L. Smith is Director of Operational Technology for Distribution Operations at DTE.[23] He testified in support of the company's historical and projected AMI costs, including an analysis of the benefits of AMI and the reasonableness of investments in communications and metering equipment. In rebuttal, he addressed Staff's reduction in the company's AMI network investment.

Pankaj Sharma is the Director and Information Officer within the Information Technology (IT) organization of DTE Energy Corporate Services, LLC.[24] He testified in support the company's historical and projected IT capital and O&M expenditures. In rebuttal, he addressed reductions to the company's historical and projected IT capital and test year IT O&M expenses recommended by witnesses for Staff and the Attorney General.

Angie M. Pizzuti is Vice President and Chief Customer Officer with DTE Energy Corporate Services, LLC.[25] She also testified in support of the company's historical and projected IT capital and O&M expenses focusing on the customer service component of IT expense. In rebuttal testimony, she disputed reductions to the company's historical and projected capital expenses and to its projected O&M expenses for customer service IT programs and projects recommended by witnesses for Staff and the Attorney General.

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[23] Mr. P. Smith's testimony is transcribed at 7 Tr 1888-1918; his qualifications are presented at 7 Tr 1889-1890.
[24] Mr. Sharma's testimony is transcribed at 7 Tr 1922-2145; his qualifications are presented at 7 Tr 1923-1924.
[25] Ms. Pizzuti's testimony is transcribed at 7 Tr 2149-2273; her qualifications are presented at 7 Tr 2150-2152.

Shannen M. Hartwick is Director of Tree Trim for DTE.[26] She testified to support DTE's historical and projected O&M expenses for tree trimming and to support its requested approval of Surge Program funding for 2023-2024. Her rebuttal testimony objected to the reduction in the company's O&M expense for tree trimming made by a witness for the Attorney General.

Benjamin J.H. Burns is Director of Electric Marketing and Electrification for DTE.[27] He testified to support the company's projected capital and O&M expenditures associated with its electric vehicle (EV) pilots, Residential Batteries pilot, Advanced Customer Pricing Pilot, and Time-of-Use pricing rollout. He also testified in support of the company's request to increase merchant fees expense and the Electric Regulated Marketing organization's O&M expense. In his rebuttal, Mr. Burns addressed recommendations regarding expansion of the Charging Forward EV pilot, the Residential Batteries pilot, and the merchant fee expenses made by witnesses for Staff, the Attorney General, MNSC, MEIBC/IEI, ChargePoint, EVgo, CEO, and Ann Arbor.

Jeffrey C. Davis is the Manager of Nuclear Strategy and Business Support for DTE. He testified in support of the company's historic and projected capital and O&M expenses for operating Fermi 2, as well as the projected Nuclear Surcharge.[28] His rebuttal testimony addressed reductions to the projected capital and O&M nuclear generation expense recommended by a witness for the Attorney General.

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[26] Ms. Hartwick's testimony is transcribed at 7 Tr 2276-2334; her qualifications are presented at 7 Tr 2277-2278.
[27] Mr. Burns' testimony is transcribed at 7 Tr 2399-2529; his qualifications are presented at 7 Tr 2400-2401.
[28] Mr. Davis's testimony is transcribed at 7 Tr 2532-2586; his qualifications are presented at 7 Tr 2533-2534.

Thomas W. Lacey is a Principal Financial Analyst in the Revenue Requirements department of DTE Energy Corporate Services, LLC.[29] He presented a study of the revenue requirements by plant/unit to comply with the Commission's order in Case No. U-20561, incorporating recommendations of Staff. In rebuttal, he addressed the critique of his analysis by a witness for MNSC and a recommendation for further studies in future cases.

Markus B. Leuker is Manager of Corporate Energy Forecasting for DTE. He presented the company's forecast of electric sales, maximum demand, and system output.[30] In rebuttal, Mr. Leuker addressed recommended revisions to the sales forecast by witnesses for Staff and the Attorney General. He also addressed testimony by a witness for Ann Arbor regarding a research study on battery attachment rates.

David C. Milo is Fuel Resources Specialist in DTE's Fuel Supply department. He testified in support of the company's historic and projected capital and O&M expenses for fuel supply and fuel handling.[31]

Theresa M. Uzenski is Manager of Regulatory Accounting for DTE Energy Corporate Services.[32] She testified in support of the financial schedules for the historical year, including the required historical schedules, and normalizing adjustments. She also testified in support of the projected capital and O&M expenses for the Corporate Staff Group (CSG), explained allocation of common costs to DTE and other

[29] Mr. Lacey's testimony is transcribed at 7 Tr 2588-2607; his qualifications are presented at 7 Tr 2589-2592.
[30] Mr. Leuker's testimony is transcribed at 7 Tr 2610-2657; his qualifications are presented at 7 Tr 2611-2614.
[31] Mr. Milo's testimony is transcribed at 7 Tr 2659-22669; his qualifications are presented at 7 Tr 2660-2662.
[32] Ms. Uzenski's testimony is transcribed at 7 Tr 2674-2796; her qualifications are presented at 7 Tr 2675-2678.

subsidiaries, and discussed several of the company's accounting requests. In her rebuttal, Ms. Uzenski addressed reductions to the CSG O&M and capital expenses recommended by witnesses for Staff and the Attorney General. She also addressed the pension expense recommendation of a witness for the Attorney General, adjustments to the overhead component of certain distribution operation capital expense projections recommended by a witness for Staff, and concerns regarding the company's capitalization policies raised by witnesses for Staff and MNSC. Ms. Uzenski further addressed the accounting for shared assets, Staff's proposed deferral accounting for Low Income Assistance (LIA) and Residential Income Assistance (RIA) credits, and Staff's proposed deferred accounting for certain generation asset removal projects

Kirk M. Vangilder is a Principal Financial Analyst in the Regulatory Affairs organization of DTE Energy Corporate Services, LLC.[33] Mr. Vangilder presented the company's historic test year revenue sufficiency calculation and the projected test year revenue deficiency calculation. He also presented the calculations of the overall rate of return, adjustments to the net operating income for interest synchronization and income tax savings, and the revenue conversation factor.

B. Staff

Staff presented the direct testimony of 24 witnesses and Exhibits S-1 through S-4, S-6, S-7.1 through S-7.52, S-8.0 through S-8.5, S-9.0 through S-9.2, S-10.0 through S-10.15, S-11.0 through S-11.9, S-12.1 through S-12.14, S-13, S-14.0 through S-14.3,

[33] Mr. Vangilder's testimony is transcribed at 7 Tr 2799-2815; his qualifications are set forth at 7 Tr 2800-2802.

S-15.0 through S-15.3, S-16.1 through S-16.11, S-17, S-18, S-18.1, S-18.2, S-19.0, S-20 through S-22, S-23.00 through S-23.02, S-24, and S-24.1 through S-24.5.

Robert F. Nichols II is the Manager of the Revenue Requirements section of the Commission's Regulated Energy division.[34] He presented the calculations of Staff's projected revenue deficiency of approximately $143 million and projected operating income.[35] Mr. Nichols explained Staff's use of the short-term debt rate to determine the return on the tree trim regulatory asset, and the accounting Staff proposes for the cost of removal associated with certain generation assets. Mr. Nichols also explained the difficulty caused by DTE's April 26, 2022 filing of amended testimony and exhibits in this matter.

Michelle L. Schreur is an auditor in the Revenue Requirements section of the Commission's Regulated Energy division. She presented Staff's projected rate base including working capital, and depreciation and amortization expense.[36]

Mark J. Pung is a Departmental Analyst in the Rates and Tariff section of the Commission's Regulated Energy division.[37] He presented Staff's calculation of projected operating revenue at current rates and Staff's rate design. He also presented Staff's calculation of voltage level distribution charges and the nuclear surcharge, and he addressed DTE's proposed changes to the outdoor lighting tariffs.

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[34] Mr. Nichols's testimony is transcribed at 8 Tr 5026-5037; his qualifications are set forth at 8 Tr 5027-5030.
[35] At the time of filing, as explained by several witnesses, Staff's projected revenue deficiency did not incorporate all of Staff's recommended adjustments due to time constraints.
[36] Ms. Schreur's testimony is transcribed at 8 Tr 5054-5061; her qualifications are presented at 8Tr 5055-5056.
[37] Mr. Pung's testimony is transcribed at 8 Tr 5038-5077; his qualifications are presented at 8 Tr 5039-5042.

Joseph E. Ufolla is a financial analyst in the Revenue Requirements section of the Commission's Regulated Energy division.[38] He presented Staff's recommended cost of capital, including a recommended return on equity of 9.6% and the capital structure DTE used.

Daniel J. Gottschalk is a departmental specialist in the Rates and Tariffs section of the Commission's Regulated Energy division, and the sections' Electric Cost of Service Specialist.[39] Mr. Gottschalk presented Staff's cost of service study. He also addressed the allocation of uncollectible expense, Staff's recommended customer charges, and the capacity revenue calculation. His rebuttal testimony addressed recommended changes to the production cost allocation raised by witnesses for the Attorney General, ABATE, and Walmart, a recommendation regarding reconciliation of capacity charge revenue raised by a witness for Energy Michigan, and the use of average line loss data proposed by a witness for ABATE.

Nicholas M. Revere is Manager of the Rates and Tariffs section of the Commission's Regulated Energy division.[40] He addressed certain of DTE's rate design proposals, including the collection of customer-related costs, the implementation of TOU rates, the creation of the Stable Bill Service Level rate, and the treatment of the DG rate, Rider 18. Mr. Revere also presented Staff's proposed allocation of AMI system costs, and Staff's calculated billing determinants and allocation schedules based on Staff's sales forecast. In rebuttal testimony, Mr. Revere addressed proposals related to

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[38] Mr. Uffola's testimony is transcribed at 8 Tr 5079-5101; his qualifications are presented at 8 Tr 5080-5081.
[39] Mr. Gottschalk's testimony is transcribed at 8 Tr 5103-5120; his qualifications are presented at 8 Tr 5104-5106.
[40] Mr. Revere's testimony is transcribed at 8 Tr 5122-515162; his qualifications are presented at 8 Tr 5123-5126.

DG raised by witnesses for the CEO, GLREA, MI MAUI and Ann Arbor, and the DAAO. He also addressed recommendations regarding the EV pilot made by witnesses for ChargePoint and MNSC, and standby rate recommendations made by witnesses for Bloom. He also addressed an additional analysis recommended by a witness for MNSC, the earnings sharing mechanism recommended by a witness for ABATE, and the treatment of streetlighting costs recommended by a witness for MI MAUI.

Joy H. Wang is public utilities engineer in the Electric Operations section of the Commission's Energy Operations division.[41] Dr. Wang presented Staff's recommended adjustments regarding DTE's community lighting program and certain distribution operation and IT capital and O&M expenditures. Dr. Wang also raised a concern with the company's capitalization of certain expenses in its distribution operations and IT programs, and she commented on the importance of equitable and resilient electric infrastructure.

Theresa McMillan-Sepkoski is an Audit Specialist in the Revenue Requirements section of the Commission's Regulated Energy division.[42] She explained Staff's recommendations regarding certain of DTE's projected O&M expenses, including employee compensation expenses, restricted stock awards, and merchant fees.

Elaina M. Braunschweig is a Departmental Analyst for the Rates and Tariff section of the Commission's Regulated Energy division.[43] She presented Staff's recommendations regarding the low-income assistance tariffs, Staff's projected

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[41] Dr. Wang's testimony is transcribed at 8 Tr 5164-5255; her qualifications are presented at 8 Tr 5165-5167.
[42] Ms. McMillan-Sepkoski's testimony is transcribed at 8 Tr 5257-5266; her qualifications are presented at 8 Tr 5258-5260.
[43] Ms. Braunschweig's testimony is transcribed at 8 Tr 5268-5285; her qualifications are presented at 8 Tr 5269-5285.

customer count, and DTE's proposed accounting change for the revenues associated with the low-income credits. In rebuttal, she addressed testimony from witnesses for the DAAO regarding DTE's proposed payment stability plan pilot and an alternative proposal for a percent-of-income payment plan.

Jonathan J. DeCooman is a Public Utilities Engineer in the Resource Optimization and Certification section of the Commission's Energy Resources division.[44] He presented Staff's recommendations regarding DTE's Headquarters Energy Center project as well as certain of the company's historical and projected capital expenses for its non-nuclear generating plant, including non-routine removal projects and non-routine projects for the non-steam "other" generating plant category.

Marceline A. Champion is a Public Utilities Engineer in the Resource Optimization and Certification section of the Commission's Energy Resources division.[45] Ms. Champion testified to Staff's recommendations regarding certain of DTE's historical and projected capital expenses for its non-nuclear generating plant, including routine projects at all plants and non-routine projects not otherwise addressed by Mr. DeCooman. She also addressed Midwest Energy Resources Company (MERC) and Fuel Supply department projects.

Danielle R. Rogers is a Departmental Analyst in the Smart Grid Section of the Commission's Energy Resources division.[46] Ms. Rogers presented Staff's recommended adjustments to DTE's historical and projected capital expenditures for

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[44] Mr. DeCooman's testimony is transcribed at 8 Tr 5287-5319; his qualifications are presented at 8 Tr 5288-5291.
[45] Ms. Champion's testimony is transcribed at 8 Tr 5321-5332; her qualifications are set forth at 8 Tr 5322-5323.
[46] Ms. Rogers' testimony is transcribed at 8 Tr 5334-5371; her qualifications are presented at 8 Tr 5335-5336.

certain IT and distribution operations expenses. She also explained Staff's concern with the company's treatment of assets shared between gas and electric operations.

Cody S. Matthews is a Public Utilities Engineer Specialist in the Renewable energy section of the Commission's Energy Resources division.[47] Mr. Matthews presented Staff's recommendations regarding the company's DG program capacity credit, the small solar and storage test bed pilot, the residentiary battery program pilot, and the battery storage demand response program. In rebuttal testimony, Mr. Matthews endorsed a GLREA witness recommendation affecting Riders 17 and 18.

Tayler Becker is a Public Utilities Engineering Specialist in the Electric Operations section of the Commission's Electric Operations division.[48] He presented Staff's recommendations regarding certain elements of DTE's projected distribution system capital and O&M expenses.

Nicholas M. Evans is the Manager of the Electric Operations section of the Commission's Electric Operations division.[49] He presented Staff's recommendations regarding the company's projected vehicle fleet and maintenance capital expense projections, and Staff's recommendations regarding certain elements of the company's distribution operations capital expense projections. Mr. Evans also addressed the test year tree trimming expenses and cost recovery of customer outage credits.

[47] Mr. Matthews' testimony is transcribed at 8 Tr 5373-5391; his qualifications are presented at 8 Tr 5374-5376.
[48] Mr. Becker's testimony is transcribed at 8 Tr 5393-5418; his qualifications are presented at 8 Tr 5394-5398.
[49] Mr. Evans' testimony is transcribed at 8 Tr 5420-5438; his qualifications are presented at 8 Tr 5421-5425.

Julie K. Baldwin is Director of the Commission's Energy Operations division.[50] She explained Staff's proposed community solar pilot program.

Shannon Rueckert is an auditor in the Revenue Requirements section of the Commission's Regulated Energy division.[51] He presented Staff's recommended uncollectible accounts expense projection for the test year.

Paul R. Ausum is an Economic Analyst in the Act 304 and Sales Forecasting section of the Commission's Energy Operations division. He presented Staff's sales forecast of electric deliveries, with adjustments for the residential bundled and small commercial and industrial bundled customer classes.

Lisa M. Kindschy is a Public Utilities Engineering Specialist in the Act 304 and Sales Forecasting section of the Commission's Energy Operations division.[52] She presented Staff's recommended adjustments to DTE's projected steam power generation O&M expense for the test year. Ms. Kindschy also explained Staff's recommendations regarding future O&M expenses for the company's Headquarters Energy Center, and she presented a calculation of projected PSCR expense based on Staff's sales forecast adjustment.

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[50] Ms. Baldwin's testimony is transcribed at 8 Tr 5440-5455; her qualifications are presented at 8 Tr 5441-5445.
[51] Mr. Rueckert's testimony is transcribed at 8 Tr 5457-5463; his qualifications are presented at 8 Tr 5457-5463.
[52] Ms. Kindschy's testimony is transcribed at 8 Tr 5475-5482; her qualifications are presented at 8 Tr 5476-5478.

Anne T. Armstrong is Director of the Commission's Customer Assistance division.[53] She discussed Staff's recommended adjustments to certain of DTE's customer-service-related historical and projected IT capital expenses.

Kevin S. Krause is a Gas Cost of Service Specialist in the Commission's Regulated Energy division.[54] He presented Staff's recommendation regarding the Rider 18 outflow credit. In his rebuttal, he addressed testimony regarding EVs, Standby Rates, and Rider 18 provided by witnesses for the CEO, GLREA, the DAAO, Ann Arbor, MEIBC/IEI, MNSC, EVgo, and Bloom.

James E. LaPan is a Public Utility Engineer with the Commission. His testimony presented Staff's findings and recommendations regarding the company's projected cost of removal for retirement of certain generating plant.[55] Mr. LaPan also addressed the company's projected capital expenditures associated with the Service Center Optimization of the Wixom pole yard.

Roger A. Doherty is an Engineer in the Resource Adequacy and Retail Choice section of the Commission's Energy Resources division.[56] Mr. Doherty presented Staff's recommendations regarding DTE's DR programs and pilots, as well as the appropriate penalties for nonperformance or underperformance during demand response events.

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[53] Ms. Armstrong's testimony is transcribed 8 Tr 5484-5499; her qualifications are presented at 8 Tr 5485-5488.
[54] Mr. Krause's testimony is transcribed at 8 Tr 5501-5510; his qualifications are presented at 8 Tr 5502-5505.
[55] Mr. LaPan's testimony is transcribed at 8 Tr 5512-5519; his qualifications are presented at 8 Tr 5513-5516.
[56] Mr. Doherty's testimony is transcribed at 8 Tr 5521-5531; his qualifications are presented at 8 Tr 5522-5524.

Allan D. Freeman is Assistant to the Division Director in the Energy Resources Division.[57] Mr. Freeman presented Staff's analysis of DTE's EV pilot programs. In rebuttal, Mr. Freeman addressed alternative EV-related recommendations made by witnesses for ChargePoint and EVgo.

C. Attorney General

The Attorney General presented the testimony of two witnesses; the Attorney General also presented Exhibits AG-1.1 through AG-1.71 and AG-2.1 through AG-2.10.

Sebastian Coppola is an independent consultant in field of public utility regulation. Mr. Coppola's testimony addressed several elements of the revenue requirements calculation for the projected test year, including rate base, cost of capital, and adjusted net operating income.

Dr. David Dismukes is a Consulting Economist with the firm Acadian Consulting Group.[58] Dr. Dismukes recommended a revised method of allocating production costs, and a revised method for allocating the demand-related secondary voltage distribution system costs.

D. ABATE

ABATE presented the testimony of four witnesses and Exhibits AB-1 through AB-36.

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[57] Mr. Freeman's testimony is transcribed at 8 Tr 5533-5550; his qualifications are presented at 8 Tr 5534-5536.
[58] Dr. Dismukes' testimony is transcribed at 8 Tr 4906-5023; his qualifications are presented at 8 Tr 4908-4910 and 8 Tr 4951-5023.

James R. Dauphinais is an Associate with the consulting firm Brubaker & Associates, Inc. (Brubaker).[59] Mr. Dauphinais testified to concerns with the use of projected capital expenses, recommending return to a "known and measurable" and an earnings-sharing mechanism. He provided an overview of the testimony of other ABATE witnesses, and a calculation showing a revenue deficiency of $183.3 million based on their testimony. Mr. Dauphinais also discussed extensively the Rider 10 administrative charge. In rebuttal testimony, he addressed revisions to the production cost allocation method recommended by witnesses for MNSC and the Attorney General.

Brian C. Andrews is an Associate with Brubaker.[60] His testimony addressed DTE's 2019 line loss study, and he explained his objections to DTE's use of that study in demand-based cost allocations and rate design, recommending alternatives.

Jessica A. York is an Associate with Brubaker.[61] Her direct testimony addressed several elements of the revenue requirements calculation, including production and distribution system capital expenditures, the inclusion of contingency factors in capital expense projections, the use of labor escalation in the O&M expense projection, and the company's incentive compensation expense.

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[59] Mr. Dauphinais's testimony is transcribed at 8 Tr 2888-2980; his qualifications are presented at 8 Tr 2890-2891 and 8 Tr 2933-2937.
[60] Mr. Andrews' testimony is transcribed at 8 Tr 2981-3005; his qualifications are presented at 8 Tr 2983-2984 and 3004-3005.
[61] Ms. York's testimony is transcribed at 8 Tr 3006-3041; her qualifications are presented at 8 Tr 3008-3009 and 8 Tr 3040—3041.

Christopher C. Walters is an Associate with Brubaker.[62] His direct testimony addressed the cost of capital for the test year, recommending an authorized return on equity of 9.40% and critiquing the analysis presented by DTE.

E. MEC, NRDC, SC, CUB (MNSC)

MNSC presented the testimony of 5 witnesses and Exhibits MEC-1 through MEC-82, MEC-86 through MEC-108, MEC-110 through MEC-114, MEC-117, MEC-118, and MEC 120 through MEC-127.

Robert G. Ozar is a Senior Consultant at 5 Lakes Energy LLC.[63] He reviewed the company's distribution system capital spending, recommending several adjustments to individual line items with additional recommendations for further analysis and alternative approaches in the future. He recommended continuing a Staff-led workgroup to reform the CAIC tariffs, and also recommended that DTE plan a survey to determine customer willingness to pay for reliability improvements as part of an overall analysis of the economic value to customers of such improvements.

Chris Neme is a co-founder and a principal with the consulting firm Energy Futures Group.[64] He presented a proposal that DTE develop a ratepayer-funded residential pilot program for electrifying propane, fuel oil and kerosene-heated homes in its service territory, explaining the importance of electrification to meet climate goals and the analysis showing the cost-effectiveness of doing this.

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[62] Mr. Walters' testimony is transcribed at 8 Tr 3042-3115; his qualifications are presented at 8 Tr 3044-3045 and 8 Tr 3113-3115.
[63] Mr. Ozar's testimony is transcribed at 8 Tr 3952-4040; his qualifications are presented at 8 Tr 3954-3956 and in Exhibit MEC-14.
[64] Mr. Neme's testimony is transcribed at 8 Tr 4085-4114; his qualifications are presented at 8 Tr 4087-4091 and in Exhibit MEC 74.

Douglas B. Jester is the Managing Partner of 5 Lakes Energy LLC.[65] He addressed several elements of DTE's rate application, discussing the drivers of the proposed rate increase, metrics to consider in evaluating DTE's performance and strategies to improve them. He focused on distribution system planning, considerations of equity, and distribution cost allocation. He explained his objection to the plant study DTE performed in response to the Commission's order in the last rate case, recommending a revision of the capacity cost calculation. He also recommended that MERC costs be allocated as fuel costs in the cost of service study, and he recommended a revision to the production cost allocation method to a 65-0-35 4 CP method. He also testified in support of DTE's EV program proposals with modifications, and in opposition to DTE's proposed "Stable Bill" Rate D1.12 and proposed changes to the Rider 18 outflow credit. In rebuttal, he addressed recommendations made by witnesses for ChargePoint and EVgo regarding DTE's proposed EV charging hubs.

David J. Garrett is the managing member of Resolve Utility Consulting, LLC and an independent consultant in the field of public utility regulation.[66] On behalf of MEC and CUB, he presented an analysis of the company's cost of capital. He recommended that the authorized return on equity be set at 8.80% and that the equity ratio be reduced to 43%, with a correspondingly higher percentage of long-term debt.

Tyler Comings is a Senior Researcher at Applied Economics Clinic, a non-profit consulting group.[67] He addressed DTE's analysis of the potential retirement dates for

[65] Mr. Jester's testimony for MNSC is transcribed at 8 Tr 3765-3862 and 4414A through 4414H.; his qualifications are presented at 8 Tr 3767-3771 and in Exhibit MEC-1.
[66] Mr. Garrett's testimony is transcribed at 8 Tr 3863-4040.
[67] Mr. Comings' testimony is transcribed at 8 Tr 4041-4084, with a confidential version in the confidential record; his qualifications are presented at 8 Tr 4043-4045 and in Exhibit MEC-53.

the Belle River and Monroe plants, recommending that the capital costs of certain projects at these plants be excluded from rates; he also recommended that the Commission reject the hydrogen generating pilot DTE proposed for BWEC until it can be reviewed in the company's upcoming IRP.

F. Clean Energy Organizations (CEO)

The CEO presented the testimony of four witnesses and exhibits CEO-1 through CEO-71.

Margarita Parra Cobaleda is the Transportation Program Director for the non-profit Clean Energy Works.[68] She provided an evaluation of the company's transit battery program and associated rider, recommending an expansion of the program to increase the number of batteries and include school buses, with an additional recommendation to seek external funding.

Kevin Lucas is the Senior Director of Utility Regulation and Policy and the Solar Energy Industries Association (SEIA).[69] He addressed DTE's proposed residential Stable Bill Rate D1.12, recommending that the Commission reject the proposal. He also addressed DTE's TOU rates, recommending an increased differential between on-peak and off-peak rates. Mr. Lucas also addressed DTE's proposed outflow credit for Rider 18 customers, characterizing it as inappropriate and not cost-based, recommending an alternative.

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[68] Ms. Cobaleda's testimony is transcribed at 8 Tr 3551-3559; her qualifications are presented at 8 Tr 3552-3553 and in Exhibit CEO-1.
[69] Mr. Lucas's testimony is transcribed at 8 Tr 3560-3646; his qualifications are presented at 8 Tr 3563-3565 and in CEO-3.

Guillermo Pereira is a Senior Energy Analyst for the Union of Concerned Scientists.[70] Dr. Pereira evaluated the company's proposed residential battery storage pilot, recommending modifications. He also provided a framework for the deployment of equitable storage through utility ownership for income eligible pilot participants, or through a range of rebates.

William D. Kenworthy is Regulatory Director of the Midwest for Vote Solar.[71] His testimony addressed the consideration of grid equity and environmental justice in distribution system planning, including a comparison of the company's Distribution Grid Plan (DGP) from Case No. U-20147 and the investments DTE proposes in this case. He recommended the use of performance incentives based on meaningful metrics of grid performance, and provided a critique of DTE's proposed strategic spending. He also endorsed Mr. Lucas's recommendations regarding the use a greater differential in TOU rates and a revised outflow credit.

G. GLREA

GLREA presented the testimony of three witnesses and Exhibits GLREA-1 through GLREA-17.

John Richter is the Senior Policy analyst for GLREA and a member of its Board of Directors.[72] He testified on a variety of rate design and tariff issues, including the current and proposed tariffs for DG, the Rider 17 green power program, and DTE's proposed residential demand-based rates and TOU rates. He also recommended

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[70] Dr. Pereira's testimony is transcribed at 8 Tr 3647-3684; his qualifications are presented at 8 Tr 3648-3651 and in Exhibit CEO-58.
[71] Mr. Kenworthy's testimony is transcribed at 8 Tr 3685-3719; his qualifications are presented at 8 Tr 3686-3688 and in Exhibit CEO-69.
[72] Mr. Richter's testimony is transcribed at 8 Tr 3124-3152; his qualifications are presented at 8 Tr 3126-3127 and in Exhibit GLREA-1.

against approval of DTE's hydrogen pilot, within generation expense, and discussed pilot programs generally, recommending against DTE ownership of charging stations and transit batteries.

Robert Rafson is a member of GLREA's Regulatory Affairs Committee and the owner of a renewable energy development company.[73] He presented recommendations regarding the cost of service and rate design for customers with behind-the-meter DG, specifically objecting to DTE's proposed Rate D1.12 and Riders 14 and 5 as successors to Rider 18. He also testified in rebuttal to Staff testimony regarding community solar.

Tom Regan is a customer of DTE who recently installed solar panels on his residence.[74] He explained his objections to DTE's rate request, focusing on its demand-based residential tariff proposal that he characterized as a fine on solar panels.

H. Detroit Area Advocacy Organization

The DAAO presented the testimony of five witnesses and Exhibits DAO-1 through DAO-100.

Gloria Lowe is the CEO and Founder of We Want Green, Too.[75] She explained her work with We Want Green, Too, provided her perspective on the energy challenges and needs of Michigan communities, and discussed her concerns with economic, discriminatory, and geographic disparities in the reliability and affordability of utility service. She discussed the Energy Burden Survey conducted by We Want Green, Too, and in light of its findings, characterized DTE's proposed residential rate increase as

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[73] Mr. Rafson's testimony is transcribed at 8 Tr 3253-3295; his qualifications are presented at 8Tr 3255-3258 and in Exhibit GLREA-16.
[74] Mr. Regan's testimony is transcribed at 8 Tr 3296-3298.
[75] Ms. Lowe's testimony is transcribed at 8 Tr 4145-4171; her qualifications are presented at 8 Tr 4146-4151.

"unconscionable." She also made recommendations regarding DTE's outage credits and its community outreach and engagement.

Brian Donovan is the general manager of the Inter-Cooperative Council in Ann Arbor.[76] He discussed energy democratization, the value of DG in giving low-income and people of color communities greater control along with the benefits of more localized energy, and barriers to access to DG in these communities. He explained Soulardarity's proposed community solar program, designed to promote access to renewable energy for low-income populations and help build wealth in their communities, and recommended that the Commission adopt this proposal rather than DTE's proposal for low-income solar.

Eban Morales is a DTE customer and resident of Highland Park as well as a member of Soulardarity.[77] He testified to negative experiences he had with DTE, focusing on a shut-off experience during the pandemic, and cited news reports to show that his experiences were not unique. After explaining his general concerns, he also addressed DTE's proposed residential battery pilot, recommending it be redesigned.

Stephanie Johnson is a Community Development Manager for Wayne Metro Community Action Agency, focusing on home repair.[78] She is also a member of Soulardarity as well as the Polar Bear Sustainable Energy Co-op, which promotes energy efficiency and home weatherization in Highland Park. She testified to describe her personal experiences with DTE and share her concern that DTE's request for a rate

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[76] Mr. Donovan's testimony is transcribed at 8 Tr 4171-4217; his qualifications are presented at 8 Tr 4173-4178.
[77] Mr. Morales's testimony is transcribed at 8 Tr 4204-4217.
[78] Ms. Johnson's testimony is transcribed at 8 Tr 4218-4218; her qualifications are set forth at 8 Tr 4219-4221.

increase for its residential customers is unjustifiable and unreasonable. She also specifically addressed DTE's payment assistance programs, efforts to help customers avoid shutoff, and efforts to improve its customer service by focusing on digital products, presenting recommendations for DTE to help customers better understand and manage their bills.

Jackson Koeppel is a co-founder of Soulardarity and an independent consultant working for the organization.[79] Mr. Koeppel focused on racial and economic class disparities in the energy system and the goal of Race-Class Equity, which he described and explained should be considered in evaluating investments in the energy system. He cited numerous journal articles, news sources, and discovery responses from DTE in support of his concerns. He specifically addressed four elements of DTE's rate case filing that he considers show the harmful effects of DTE's focus on profits: the overall level of the residential rate increase; further limits on the financial benefits of DG and lack of support for community solar; the utility-ownership element of its residential battery program; and its distribution system infrastructure investment plans including its 4.8kV hardening program. In rebuttal, Mr. Koeppel took issue with testimony by a witness for the Attorney General citing increased renewable energy as a driver of increased cost, recommended modifications to Staff's proposed community solar program, and objected to a value of reliability study proposed by a witness for MNSC to the extent it would focus on "willingness to pay" for reliability, recommending an alternate focus for a workgroup.

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[79] Mr. Koeppel's testimony is transcribed at 8 Tr 4255-4367; his qualifications are presented at 8 Tr 4256-4259.

I. MI MAUI

MI MAUI presented the testimony of nine witnesses, along with Exhibits MAUI-1 through MAUI-57.

Richard Bunch is the Executive Director of MI MAUI and a Senior Consultant at 5 Lakes Energy, LLC.[80] He presented numerous recommendations regarding the company's lighting program, and also addressed the company's residential customer deposit tariffs and practices, which he characterized as harmful and not cost-effective. Mr. Bunch also provided an overview of the testimony of other witnesses testifying for MI MAUI.

Rhonda Bauma is the Superintendent at Rolling Hills County Park in Ypsilanti, overseen by the Washtenaw County Parks and Recreation Commission.[81] While not offering expert testimony, she explained the financial and equipment losses at Rolling Hills due to power quality issues and the need for reliable service, recommending that DTE be required to compensate customers for damages attributable to power loss and poor power quality.

Joseph Gacioch is the City Manager for the City of Ferndale.[82] While not presenting expert testimony, he explained the impacts that power outages have had on the municipality's ability to serve the community, in addition to impacts on residents and businesses.

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[80] Mr. Bunch's testimony is transcribed at 8 Tr 3409-3484; his qualifications are presented at 8 Tr 3411-3413 and in Exhibit MAUI-1.
[81] Ms. Bauma's testimony is transcribed at 8 Tr 3402-3408; her qualifications are set forth at 8 Tr 3403-3404.
[82] Mr. Gacioch's testimony is transcribed at 8 Tr 3485-3488; his qualifications are presented at 8 Tr 3486.

Raymond Hess is the Transportation Manager for Ann Arbor.[83] While not presenting expert testimony, he described his experience managing Ann Arbor's streetlights, both municipally-owned and utility-owned. He testified regarding DTE's light removal costs, installation and conversion costs, outage frequency and recent DTE efforts to reduce and shorten outages, and requested Commission action.

James Krizan is the City Manager for Lincoln Park.[84] While not presenting expert testimony, he described his experiences with DTE's reliability in his current position, including a discussion of the impact of power outages on the Lincoln Park's ability to deliver municipal services, as well as its finances. He provided recommendations for further Commission action.

Thomas Lyon is the Dow Chair of Sustainable Science, Technology and Commerce at the University of Michigan.[85] He testified regarding DTE's surge protection program, explaining what he learned about the surge protection program from reviewing DTE's advertising material and webpage and through discussions with company employees, and provided his opinion as an economist that the program should be rejected, with additional recommendations should the Commission approve the program.

Thomas Power is Superintendent of Maintenance for the Washtenaw County Parks and Recreation Commission.[86] While Mr. Power did not offer expert testimony, he described the Washtenaw County Parks and Recreation Commission's operational and

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[83] Mr. Hess's testimony is transcribed at 8 Tr 3489-3509; his qualifications are set forth at 8 Tr 3490-3491.
[84] Mr. Krizan's testimony is transcribed at 8 Tr 3510-3515; his qualifications are set forth at 8 Tr 3511.
[85] Mr. Lyon's testimony is transcribed at 8 Tr 3516-3531; his qualifications are presented at 8 Tr 3517-3519 and in Exhibit MAUI-33.
[86] Mr. Powers' testimony is transcribed at 8 Tr 3532-3538; his qualifications are set forth at 8 Tr 3533.

financial experiences with poor electrical reliability and power quality outages at Independence Lake, a County waterpark. He provided recommendations for the Commission.

Sue Shink is a Washtenaw County Commissioner and chair of the Board of Commissioners for the County.[87] She did not offer expert testimony, but from her vantage point, described her view of the impact DTE's rates are having on the residents and businesses she represents, and provided recommendations to the Commission to focus on performance in setting rates of return and providing for executive compensation.

J. City of Ann Arbor

Ann Arbor presented the testimony of five witnesses and Exhibits AA-1 through AA-41.

Tiffany Giacobazzi is an ISA Certified Arborist.[88] She described the benefits of tree trimming based on her experience, including promoting reliability and safety.

Matthew Grocoff is a founder of and principal at Thrive Collaborative, Inc., a real estate development, design building and consulting firm.[89] He described the all-electric Veridian development that is the subject of a DTE non-wires alternative projects. He testified that DTE did not work with the community on the development of that project, and he also recommended against approval of the company's proposed battery pilot program.

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[87] Ms. Shink's testimony is transcribed at 8 Tr 3539-3550 her qualifications are set forth at 8 Tr 3540-3541.
[88] Ms. Giacobazzi's testimony is transcribed at 8 Tr 3302-3305; her qualifications are presented at 8 Tr 3303-3304.
[89] Mr. Grocoff's testimony is transcribed at 8 Tr 3306-3313; his qualifications are presented at 8 Tr 3307-3309.

Melissa Stults is the Sustainability and Innovations Director for Ann Arbor.[90] Dr. Stults explained Ann Arbor's concerns that DTE is insufficiently integrating climate projections into its decision-making and insufficiently focusing on improving reliability. She also explained the city's objections to DTE's proposed Rate D1.12. In rebuttal, Dr. Stults addressed a DAAO objection to DTE's projected IT expenditure for low-income solar, citing Ann Arbor's discussions with DTE to show the potential for outside funds.

Fang Wu is the Energy Manager for Ann Arbor.[91] She explained her concerns with the company's proposed Rate D1.12. In addition to concerns with the impacts of the proposed rate, she raised concerns with the level of data available to customers to evaluate generation and usage.

Julie Roth is a Senior Energy Analyst in Ann Arbor's Office of Sustainability and Innovations.[92] While not offering expert testimony, she explained two studies DTE undertook regarding DG participants, and explained her experience working with Washtenaw County residents considering solar purchases.

K. Local 223

Local 223 presented the testimony of one witness.

Dennis Smith is journeyman underground cable splicer for DTE and a member of Local 223, Underground Lines Division.[93] He testified in support of the company's strategic undergrounding pilot program, within DTE's distribution operations, reviewing

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[90] Dr. Stults' testimony is transcribed at 8 Tr 3314-3344; her qualifications are presented at 8 Tr 3315-3316 and in Exhibit AA-2.
[91] Ms. Wu's testimony is transcribed at 8 Tr 3345-3386; her qualifications are presented at 8 Tr 3346-3347 and in Exhibit AA-22..
[92] Ms. Roth's testimony is transcribed at 8 Tr 3387-3397; her qualifications are set forth at 8 Tr 3388-3389.
[93] Mr. D. Smith's testimony is transcribed at 8 Tr 3117-3121; his qualifications are presented at 8 Tr 3118-3119.

the safety hazards presented by overhead lines and comparing worker safety data related to overhead and underground lines.

L. MEIBC/IEI

MEIBC/IEI presented the testimony of two witnesses and Exhibits EIB-1 through EIB-17.

Laura Sherman is the President of MEIBC and IEI.[94] Dr Sherman testified in support of DTE's EV proposals, with modifications, and also recommending that DTE develop a permanent program for its next rate case. She recommended that the Commission encourage DTE to eliminate or increase the DG cap. She also explained her concerns regarding the company's proposed grid scale (Slocum) and residential battery storage pilots, recommending that DTE be required to evaluate third-party ownership of the grid scale batteries and include energy storage experts and developers in stakeholder meetings, and recommending that the Commission reject the residential battery pilot.

Justin R. Barnes is Director of Research with EQ Research LLC.[95] He recommended that the Commission reject the company's proposed residential demand rate, Rate D1.12, and revised Rider 18 outflow credits, also asking that the current program be held in place for current customers. He further recommended that the Commission redesign the DG program, including a monthly netting regime and time-of-use rates.

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[94] Dr. Sherman's testimony is transcribed at 8 Tr 4370-4418; her qualifications are presented at 8 Tr 4372-424376 and in Exhibit EIB-1.
[95] Mr. Barnes' testimony is transcribed at 8 Tr 4419-4482; his qualifications are presented at 8 Tr 4421-4423 and in Exhibit EIB-10.

M. Energy Michigan

Energy Michigan presented the testimony of one witness and Exhibits EM-1 through EM-7.

Alexander J. Zakem is an independent consultant in the fields of merchant energy and utility regulation. He recommended revisions to the SRM capacity change. He also objected to certain measures within DTE's employee incentive plans and proposed additional tariff language to clarify DTE's revisions to the RASR.[96] In rebuttal, Mr. Zakem presented a revised SRM calculation to reflect Staff's proposed production revenue requirement.

N. Walmart

Walmart presented the testimony of Lisa V. Perry and Exhibits WAL-1 through WAL-1 through WAL-4.

Lisa V. Perry is Senior Manager of Energy Services for Walmart. She explained Walmart's concerns with the company's proposed rate increase, recommending that the Commission closely examine the company's revenue requirement. She discussed the utility's required return on equity in the context of the current regulatory framework and information regarding rates of return authorized for other utilities across the country. She also addressed cost of service, focusing on methods to allocate of production costs but not recommending a change to the current method at this time. She also addressed DR programs, explaining Walmart's interest in expanding its DR offerings for C&I

[96] Mr. Zakem's testimony is transcribed at 8 Tr 4484-4522; his qualifications are presented at 8 Tr 4485-4486 and in Exhibit EM-1.

customers along with Walmart's concern with nonperformance penalties under current programs.

O. Kroger

Kroger presented the testimony of Justin Bieber and Exhibits KRO-1 and KRO-1R.

Justin Bieber is an Associate Principal for the consulting firm Energy Strategies, LLC.[97] He addressed DTE's proposal to defer outage credit expenses for outages the company is not responsible for, recommending that the Commission deny the request. He also addressed revised testimony DTE submitted increasing its capacity revenue requirement from the originally filed value. He recommended that DTE be required to revise its rate design correspondingly to maintain a similar alignment between the proposed rate and cost of service. In rebuttal, Mr. Bieber addressed recommendations made by witnesses for MNSC, Energy Michigan, and ABATE. He recommended that the Commission adopt Mr. Zakem's proposal to eliminate a "true up" of projections when the capacity charge was not actually applied to any entity. He recommended against revising the production cost allocation as recommended by MNSC, and he recommended that the Commission adopt ABATE's proposal to use demand line loss factors in calculating demand allocation factors, with further recommendations for the company's next rate case.

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[97] Mr. Bieber's testimony is transcribed at 8 Tr 4626-4673; his qualifications are presented at 8 Tr 4643-4645.

P. Gerdau

Gerdau presented the testimony of Jeffry Pollock and Exhibits GER-1 through GER-5.

Jeffry Pollock is an energy advisor and President of J. Pollock, Inc., a consulting firm.[98] Mr. Pollock addressed DTE's proposal to revise the Rate R10 rate design, recommending that the administrative charge be eliminated or in the alternative, phased out, beginning with this case.

Q. Bloom Energy

Bloom Energy presented the testimony of two witnesses and Exhibits BE-1 through BE-1 through BE-7.

Peter Morse is an internal utility rate expert at Bloom. He recommended modifications to DTE's standby tariff, Rider 3, to encourage investment in Bloom's solid oxide fuel cell technology.[99] He described the technology and its potential benefits including reliability and resilience.

Mr. Jester also testified on behalf of Bloom.[100] In this testimony, he proposed changes in the rate design for Rider 3, including changes in the generation reserve fees, distribution charges, power supply demand charges, and method for calculating contract capacity.

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[98] Mr. Pollock's testimony is transcribed at 8 Tr 3721-3760; his qualifications are presented at 8 Tr 3725-3726 and 8 Tr 3742-3760.
[99] Mr. Morse's testimony is transcribed at 8 Tr 4524-4537; his qualifications are presented at 8 Tr 4525 and in Exhibit BE-1.
[100] Mr. Jester's testimony is transcribed at 8 Tr 4538-4558; his qualifications are reprised at 8 Tr 8 Tr 4539-4543 and in Exhibit BE-6.

R. ChargePoint

ChargePoint presented the testimony of Matthew Deal and Exhibits CP-1 through CP-5.

Matthew Deal is Manager of Utility Policy for ChargePoint. He addressed DTE's proposed expansion of its EV programs.[101] He generally supported the proposed expansion of programs for residential and commercial customers, with modifications, while opposing DTE's request to own and operate charging stations. His rebuttal testimony presented further recommendations regarding the EV programs in response to testimony provided by witnesses for Staff, MNSC, EVgo, MEIBC/IEI, GLREA, and ITC.

S. EVgo

EVgo presented the testimony of Carine Dumit and Exhibits EVG-1 through EVG-11.

Carine Dumit is Director of Market Development and Public Policy for EVgo, which owns and operates a network of public EV fast charging stations across 30 states and 850 locations.[102] She expressed general support for DTE's proposed expansion of its EV programs, recommending increases in the make-ready rebate budget and the reallocation of money DTE proposed for a commercial charging-as-a-service (CaaS) program, and other modifications. In rebuttal, she addressed EV program-related recommendations made by witnesses for MNSC, MEIBC/IEI, and ITC.

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[101] Mr. Deal's testimony is transcribed at 8 Tr 4598-4621; his qualifications are presented at 8 Tr 4562-4564 and in Exhibit CP-1.
[102] Ms. Dumit's testimony is transcribed at 8 Tr 4677-4712; her qualifications are presented at 8 Tr 4678-4679.

T. Zeco (d/b/a Shell Recharge Solutions)

Zeco presented the testimony of Thomas Ashley and Exhibit SRS-1.

Thomas Ashely is Vice President of Policy & Market Development for Zeco.[103] He testified in rebuttal to respond to issues raised by witnesses for MEIBC/IEI, ChargePoint, and Evgo, generally supporting DTE's proposals.

U. ITC

ITC presented the testimony of two witnesses and Exhibits ITC-1 through ITC-4.

Kwafo Adarkwa is Director of Public Affairs for ITC Holdings Corp.[104] He testified in support of DTE's proposed EV Charging Hub, characterizing the promotion of EV in Michigan as urgent and discussing ITC's planned participation.

John Kopinski is a Principal Engineer in Regional Planning for ITC Holdings Corp. He testified to the importance of the transmission system for prudent planning, and discussed the Resource Adequacy construct in connection to DTE's analysis of its projected capacity requirements. He agreed with DTE's conclusion that MISO's Local Resource Zone 7 is at risk of violating federal reliability standards, and further discussed the details ITC needs from DTE for proper transmission planning.

III.

LEGAL STANDARDS

Before addressing the disputes among the parties regarding revenue requirements, cost allocation, rate design, and other matters, it is appropriate to review

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[103] Mr. Ashley's rebuttal testimony is transcribed at 8 Tr 4715-4729; his qualifications are presented at 8 Tr 4716-4717 and Exhibit SRS-1.
[104] Mr. Adarkwa's testimony is transcribed at 8 Tr 4624-4627; his qualifications are presented at 8 Tr 4624-4625.

certain legal issues.[105] It is axiomatic that the Commission is required to set rates that are just and reasonable. Ratemaking is essentially a legislative function, and the Commission is not bound by any particular method or formula in exercising this legislative function. The Commission is required to balance the interests of the public utility and the consuming public.

DTE begins its brief with a discussion of the legal standards applicable to rate cases. Most of DTE's argument is not controversial. In addition, DTE makes some generalized claims regarding its constitutional rights in responding to several arguments raised in this case. For example, in its reply brief, DTE argues it has constitutional protections against "takings" and "confiscatory rates" and "is entitled to rates that provide a corresponding recovery for infrastructure investments that provide safe and reliable service to its customers."[106] DTE then argues that a matter of fundamental ratemaking law, it is entitled to a commensurate return of and on its investment in providing utility service.[107] DTE properly cites *Federal Power Comm v Hope Natural Gas Co*, 320 US 591 (1944) and *Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679 (1923) in this context, because these are considered seminal cases in which the Court explained the return that is required, as discussed in section VI below.

In the context in which DTE cites these cases, however, is important to note that the Commission has broad discretion in determining the appropriate amount of investment on which a return will be computed. The Michigan Supreme Court has long

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[105] In general, quotations in this PFD omit citations that were included in the quoted material.
[106] See DTE brief, page 13 at n 28.
[107] See DTE brief, page 14, at n 29.

recognized this principle. In 1920, discussing the authority of the Commission's predecessor agency, the Michigan Railroad Commission, the Court explained:

> On matters involving the exercise of good common sense and judgment only, the determination of the commission must be held to be final unless such determination in its application results in the establishment by 'clear and convincing' proof of a rate so low as to be confiscatory or so high as to be oppressive. What return a public utility shall be entitled to earn upon its invested capital and what items shall be considered as properly going to make up the sum total of that invested capital are questions of fact for the determination of the commission, and their conclusions thereon, upon which the rate is based, are unassailable unless, as a necessary result, it can be affirmatively asserted that the resultant rate is unreasonable and unlawful.
>
> Between the point where a rate may be said to be so low as to be confiscatory and the point where it must be said to be so high as to be oppressive upon the public there is a 'twilight zone' within which the judgment of the commission may operate without judicial interference. Assume that the commission, in determining the amount of the capital invested, allows as an element of the sum an amount which the court, if charged with the initial duty of determination, might find to be excessive or inadequate, or assume that the commission, in the exercise of its best judgment, permitted a rate of return upon the invested capital higher or lower than the court, under like circumstances, might believe to be proper; nevertheless the court would not be warranted in interfering unless the rate, as established, was clearly unreasonable and unlawful.[108]

In the *Hope* case, the United States Supreme Court explicitly held:

> *"[I]t is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable, judicial inquiry ... is at an end. The fact that the method employed to reach that result may contain infirmities is not then important."* [109]

The Supreme Court has more recently affirmed this principle in *Duquesne Light Co v Barasch*, 488 US 299 (1989), holding that a Pennsylvania statute that excluded plant from an electric utility's rate base that was not in use and useful did not result in an

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[108] See *City of Detroit v Michigan R.R. Comm'n*, 209 Mich 395, 433–34 (1920).
[109] *Fed Power Comm'n v Hope Nat Gas Co*, 320 US 591, 602 (1944)

unconstitutional taking of the utility's property where the overall rate was within constitutional requirements. Similarly, in *Verizon Commc'ns, Inc v FCC,* 535 US 467 (2002), the Court held that the FCC's use of the non-traditional Total Element Long-Run Incremental Cost (TELRIC) method did not raise constitutional concerns. The *Verizon* Court explained:

> At the outset, it is well to understand that the incumbent carriers do not present the portent of a constitutional taking claim in the way that is usual in ratemaking cases. They do not argue that any particular, actual TELRIC rate is "so unjust as to be confiscatory," that is, as threatening an incumbent's "financial integrity." *Duquesne Light Co* [488 US at 307, 312] . . . .
>
> This want of any rate to be reviewed is significant, given that this Court has never considered a taking challenge on a ratesetting methodology without being presented with specific rate orders alleged to be confiscatory. See, *e.g., Duquesne Light Co* [488 US *at* 303–304] (denial of $3.5 million and $15.4 million increases to rate bases of electric utilities); *Smyth v Ames,* [169 US 361, 470–476 (1898)] (Nebraska carrier-rate tariff schedule alleged to effect a taking). Granted, the Court has never strictly held that a utility must have rates in hand before it can claim that the adoption of a new method of setting rates will necessarily produce an unconstitutional taking, but that has been the implication of much the Court has said. See *Hope Natural Gas Co* [320 US 591, 602] ("The fact that the method employed to reach [just and reasonable rates] may contain infirmities is not ... important"); *Natural Gas Pipeline Co* [315 US 575, 586 (1942)] ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas"); [*Los Angeles Gas & Elec Corp v Railroad Comm'n of Cal,* 289 US 287, 305 (1933)] ("[M]indful of its distinctive function in the enforcement of constitutional rights, the Court has refused to be bound by any artificial rule or formula which changed conditions might upset"). Undeniably, then, the general rule is that any question about the constitutionality of ratesetting is raised by rates, not methods.[110]

[110] *Verizon Commc'ns, Inc v FCC,* 535 US 467, 523–25 (2002).

Thus, in the absence of any issue rising to the level of a constitutional concern, this PFD looks to past Commission decisions addressing various rate case elements for guidance in determining how to resolve disputes among the parties.

IV.

TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both the regulated utility and its customers. The Commission has explained that the selection of an appropriate test year has two components:

> First, a decision must be made regarding a 12-month period to be used for setting the utility's rates. A second determination must then be made regarding how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula. The Commission may use different methods in establishing values for these components, provided that the end result is a determination of just and reasonable rates for the company and its customers.[111]

In developing its rates for this proceeding, DTE relied on a projected test year from November 1, 2022 through October 31, 2023, explaining that, in determining test year amounts, it began with the 2020 historical year, normalized and adjusted for known and measurable changes.[112] At the time of filing, DTE had estimates but not final values for 2021 spending, and projections for the remaining 10 months of the bridge period—the 22-month period spanning the time between the end of the historical year 2020 and the beginning of the future test year, November 1, 2022—and for the test year.

ABATE witness Mr. Dauphinais discussed DTE's use of a projected test year as a major driver of rate increases in this and prior proceedings, presenting an illustrative

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[111] See January 11, 2010 order, Case No. U-15678, page 9.
[112] See Crozier, 7 Tr 2352.

chart at 8 Tr 2896. He testified: “[T]he use of a projected test year allows DTE to begin recovery of costs before these costs have been verified as being real and prudently incurred.”[113] He explained the adverse impacts he attributed to this:

> First, it has caused and continues to cause customers to experience rate increases sooner than they would under the use of a historical test year.
>
> Second, it has eliminated and continues to eliminate the incentive for DTE to contain costs that would otherwise exist due to the regulatory lag effect associated with the use of a historical test year.
>
> Third, it has allowed and continues to allow DTE to fill its projections with proposed capital expenditures and expenses that either DTE has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so to improve its realized rate of return for its shareholders. This can allow DTE to collect revenue from its customers for capital expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits DTE’s shareholders at the expense of DTE’s customers.
>
> Finally, the use of a projected test year greatly handicaps the Commission Staff and intervenors in reviewing DTE’s rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures and expenses reflected on DTE’s books, but rather projections developed over many separate cost subaccounts and revenue categories. This requires much more time and greater resources than are necessary in a rate proceeding that utilizes a historical test year all while the rate case timing has been compressed down to a 10-month time frame. As a result, while some inappropriate cost projections by DTE may be identified and successfully disallowed as a result of Commission Staff and intervenor review of DTE’s projections, many other inappropriate cost projections may be missed and inappropriately included in DTE’s rates at the expense of its customers.[114]

Mr. Dauphinais disputed that the company used a ‘known and measurable change’ standard in its rate case filing, defining known and measurable changes as “inescapable

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[113] 8 Tr 2896.
[114] 8 Tr 2897.

and precisely identifiable in amount and timing."[115] He juxtaposed this standard against his view of DTE's filing:

> When they are escapable or not precisely identifiable with respect to amount and timing, they are not known and measurable changes from the historical test year. Furthermore, many of the capital expenditures and expenses that DTE has attempted to recover in past general rate cases and is attempting to recover in this current proceeding, as shown by the direct testimony of my colleague, Ms. York, are highly speculative. These include contingency amounts that DTE may never experience as well as capital expenditures and expenses that DTE has not irrevocably committed to make. These too are not known and measurable changes from the historical test year.[116]

He recommended vigilance in evaluating rate case projections, urging the Commission to "[ensure] the expenses and investments being projected by DTE for its projected test year are truly supported by evidence demonstrating these are expenses and investments that are necessary to provide reliable electric service at lowest reasonable cost," and are precisely quantified, definitive as to time, and unavoidable.[117] He also recommended an earnings-sharing mechanism, which is discussed in more detail below, and as a longer-term measure, recommended that the Commission consider a collaborative work group to discuss the experience and impact of all the rate case filings requirements and evaluate the use and appropriate limitations on the of projected test years. This long-term recommendation is also discussed in more detail below.

In rebuttal, Ms. Crozier disputed that the company's use of a projected test year allows the company to begin recovering costs before they have been verified as being real and prudently incurred:

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[115] 8 Tr 2898.
[116] 8 Tr 2898.
[117] 8 Tr 2902.

> The Company's use of a projected test year does not mean that the projected costs are unverified. The Company is required to provide substantial support for its projections. As evidenced by over 1,600 pages of direct testimony and over 2,700 pages of exhibits as well as responding to over 5,200 audit and discovery requests, MPSC Staff and the intervening parties have been provided unprecedented access that permitted rigorous examination of the Company's request in this contested case docket. There is no reasonable basis to conclude that the regulatory process is lacking in any meaningful respect. A claim that the costs, particularly those ultimately approved for recovery, are unverified simply disregards the substantial due process provided.[118]

She also emphasized the importance of matching rates to the period when rates will be in effect. As discussed below, she also addressed Mr. Dauphinais's proposed earnings-sharing mechanism.

ABATE's brief reviews Mr. Dauphinais's analysis, urging the Commission to adopt his recommendations regarding the filing requirements and earnings-sharing mechanism, and urging the Commission to be vigilant in reviewing rate base projections:

> [T]he Commission should be extremely vigilant in ensuring DTE's projected expenses and investments are truly supported by evidence demonstrating they are necessary to provide reliable electric service at lowest reasonable cost. The Commission should also ensure the Company is irrevocably committed to incurring its projected expenses and investments or otherwise cannot avoid them. Further, the Commission should require that the spending approved in this proceeding is either carried out by DTE, or the excess and unnecessary revenue collected is proportionally and directly returned to the customers from which it was collected using bill credits. To this end the Commission should ensure projected investments and expenses are precisely quantified and tracked in detail by DTE with respect to both amount and the specific quarter in which DTE incurs these investments and expenses. Considering the past trends and historic $111.7 million sufficiency described above it is clear DTE will essentially continue to earn a rate of return higher than authorized unless and until this issue is addressed more directly.[119]

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[118] 7 Tr 2388-2389.
[119] ABATE brief, 6-7.

DTE addressed Mr. Dauphinais's testimony in its initial brief regarding the use of a projected test year, quoting the following statement from Commission's order in Case No. U-20561:

> 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.]

DTE adds a reference to the RCG's appeal of the Commission's decision in that case:

> 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).

And then DTE appears to argue that the Commission is required to adopt projections without adequate assurance that the money will be spent as projected:

> 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 must apply that plain language, regardless of ABATE's disagreement with how our Legislature wrote it.[120]

DTE maintains, however, that the company has verified its costs, citing Ms. Crozier's summary showing that DTE filed over 1,600 pages of direct testimony, over 2,700 pages of exhibits, and responses to over 5,600 audit and discovery requests.[121]

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[120] DTE brief, 16.
[121] DTE brief, 16; also see DTE reply, 8-9.

In its reply brief, Staff addressed DTE's argument that its projected costs are "verified" or that it has used a known and measurable change standard:

> While the Company may have based some of its projections on historical amounts in various ways, the Company's proposed test year is not accurately described as merely "normalizing and adjusting" the historical test year nor is it equivalent to a fully projected test year. It is a fully projected test year that substitutes projections for historical amounts and should be recognized and treated as such.[122]

Staff also defends the Commission's ratemaking authority:

> The Company also implies that the plain language of the governing statute is somehow counter to ABATE witness Dauphinais' claim that the Commission does not have to set rates using a projected test year. (Company Initial Brief, p 15-16.) As the Company notes, MCL 460.6a(1) states: "**A utility may** use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." (Emphasis added.) As is clear from a reading of the plain language of the statute, the utility is allowed to file using a future test year based on projections but creates no obligation on the part of the Commission to accept same. Hence the use of the words "utility" and "may" rather than "Commission" and "must", and a reference to the utility developing its proposals rather than what the Commission approves. Therefore, ABATE witness Dauphinais is indeed correct that the Commission is in no way required by the statute to set rates using a projected test year.[123]

Staff further endorses ABATE's view that the use of projected test years allows the recovery of costs before they are verified and found reasonable and prudent:

> The Company then further implies the statutory language discussed above is somehow dispositive of ABATE witness Dauphinais' claim that projected test years allow recovery of costs before they are verified and found reasonably and prudently incurred, stating "[t]his 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 must apply that plain language, regardless of ABATE's disagreement with how our Legislature wrote it." (Company Initial Brief, p 16.) ABATE witness Dauphinais is in no way suggesting that the Commission not apply the

[122] Staff reply, 27.
[123] Staff reply, 27-28.

> plain language of the statute, the appropriate interpretation of which is discussed above. Nor is the witness taking issue with what the Legislature wrote (unlike the Company, it appears). In addition, ABATE witness Dauphinais' statement is factual. Relying on projections does, in fact, allow for recovery before costs are verified and determined to be reasonably and prudently incurred as the costs have, by the very nature of them as projected, not been incurred, and are therefore impossible to verify as being spent, let alone whether they were spent reasonably and prudently.[124]

While this PFD agrees that it is reasonable to use a projected test year to set rates for a 12-month period following the expected date of a Commission order in this case, as quoted at the outset of this discussion, the Commission has made clear that it is not required to include projected expenses that it finds unsupported or if it believes there is a material likelihood the money will not be spent as projected. DTE's claims to have supported its projections are evaluated below.

V.

RATE BASE

A utility's rate base consists of the capital invested in used and useful utility plant, plus the utility's working capital requirements, less accumulated depreciation. In its application, DTE projected a total electric rate base of approximately $21.27 billion, which it revised to $21.24 billion in its initial brief. In its direct case, Staff calculated a $644 million reduction to DTE's filed rate base, acknowledging that due to time constraints, this value did not fully reflect Staff's analysis. Staff's brief revised its projected rate base to $20.63 billion, a $636 million reduction to DTE's filed rate base. The Attorney General recommended a $680 million reduction to rate base.[125] ABATE

[124] Staff reply, 28.
[125] Exhibit AG-1.51, Attorney General brief, 95.

recommended a $826 million reduction to rate base.[126] Although not computing a revised rate base, several parties addressed individual capital expense items. The parties' briefs and reply briefs reflect certain additional concessions that may not be fully captured in these rate base values.

Net plant is the primary component of rate base, and its key elements are total utility plant – plant in service, plant held for future use, and construction work in progress (CWIP) – less the depreciation reserve, which includes accumulated depreciation, amortization and depletion. DTE projects an increase of $2.86 billion increase in net plant from its adjusted 2020 level to the projected test year.

DTE presents its historical test year, bridge period, and projected test year capital expense projections in Schedule B5 of Exhibit A-12, broken down into the following categories: production plant (lines 2-5); nuclear production (line 6); distribution system plant (line 7); community lighting (line 8); demand-side management (line 9); information technology (line 10); corporate staff (line 11); Charging Forward (line 12); and residential battery pilot (line 13). Additional detail is presented in subsequent schedules in Exhibit A-12 and in other exhibits. Disputes regarding the capital expense projections in these categories are discussed below.

In evaluating the arguments of the parties, the ALJ takes note of the standards the Commission has articulated in prior cases. The Commission has also made clear that the company must establish the credibility of its projections:

> In a related concern, DTE Electric repeatedly asserts that the ALJ's rejection of the company's position on certain costs violates MCL 460.6a(1), which provides that "A utility may use projected costs and

[126] York, 8 Tr 3020.

revenues for a future consecutive 12-month period in developing its requested rates and charges." According to DTE Electric, any failure to approve costs projected by the company not only violates Section 6a(1) but also invades the company's constitutionally protected right against takings. The Commission has rejected this argument in the past:

> The Commission rejects [the] assertion that simply because an amount is projected, it must therefore be granted lest the Commission violate the utility's statutory right to rely on projections. In the statute providing for the use of a projected test year, nothing eliminated the requirement that all rate increases must be shown to be just and reasonable. MCL 460.6a(1); see, also, MCL 460.6, 460.54, and 460.551 et seq. The same statutory section that allows for use of projected costs also requires that Page 9 U-18014 the "utility shall place in evidence facts relied upon to support the utility's petition or application to increase its rates." MCL 460.6a(1). The ALJ observed that her recommendations do not preclude the company from seeking environmental capital expenditures in its next rate case that were also sought in this rate case. That is not a holding, or a suggestion. Whether Consumers chooses to do so is entirely in the utility's discretion. Whenever it chooses to do so, however, if the utility realistically expects inclusion of the total projected costs, it must supply the Commission with enough evidence to support a finding that the costs are just and reasonable – in the absence of thorough, detailed, and meaningful evidence, the Commission's hands are tied.

June 12, 2012 order in Case No. U-16794, p. 13.

Moreover, in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test period.[127]

The Commission has also explained:

> As the Commission discussed in its November 2, 2009 order in Case No. U-15645, p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus

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[127] January 13, 2017 order, Case No. U-18014, pages 8-9.

> "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[128]

Also relevant to the evaluation of rate base projections, the Commission has rejected the use of contingency in projections, as well as the use of placeholders in rate case filings, through which the utility fills in missing details or determines the project scope after its filing has included projected expenditures.

In a recurring argument, primarily in response to ABATE and Staff recommendations, DTE seems to suggest it is entitled to have expense projections placed in rate base without regard to when the project will be completed. In its brief, it argues that "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," with a footnote that states:

> 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).[129]

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[128] January 11, 2010 order, Case No. U-15768, pages 9-10; also see September 8, 2016 order, Case No. U-17895, page 4.
[129] DTE brief, 58 at n34.

In its reply brief, again responding to an ABATE argument, DTE argues:

> ABATE's Initial Brief, p 43, further asserts that "[b]ecause the project will not be used or useful within the period implicated by this case the Commission should reject recovery here." To the contrary, the Court of Appeals previously rejected ABATE's argument that the Commission is required to use the "used and useful" test in setting rates. ABATE v Public Service Comm, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). This is controlling precedent that must be followed. MCR 7.215(C)(2) and (J)(1). Therefore, based on the law and the record, ABATE's proposed disallowance should be rejected[.][130]

And in objecting to a Staff argument about a project in-service date, DTE argues: "Staff's suggestion of a "used and useful" requirement is contrary to controlling law."[131] DTE thus seems to turn the Commission's discretion to approve projected spending for projects that will not be used and useful by the end of the test year into an obligation for the Commission to approve projected spending for such projects. There is no constitutional takings concern with following the "used and useful" doctrine. The Commission has discretion to determine whether to include expenses in rate base when the investment is not currently providing service to ratepayers. While the Commission has not followed a strict policy, where the company's plans are indefinite, where its expense projections are not based on a firm contract or even a detailed engineering study, it is clearly reasonable for the Commission to consider this well-established doctrine along with other evidence.

As the discussion below shows, DTE argues that it has supported its projections based on the pages of testimony and exhibits it has submitted and the number of discovery responses it has addressed. But for certain important projection types, DTE's

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[130] DTE reply, 16.
[131] DTE reply, 69.

supporting detail is minimal, with no orderly presentation of the pace of work of the projects or “timelines”, often with no presentation of the total cost of the project or the projected completion date, or quantification of benefits. As parties look to DTE’s historical underspending on certain projects, DTE argues that they should also consider projects in which DTE spent more than it forecast, although DTE made no specific effort to show that the overspending was reasonable and prudent and not attributable to poor management. This PFD concludes that the Commission should be concerned that the company’s rush to present spending proposals in rate cases is contributing to a rush to spend money on projects, without following steps in a logical order. For example, and as is discussed below, DTE is anxious to proceed with its strategic undergrounding pilot without presenting any report on its first and incomplete (Appoline) pilot, even though it acknowledges that it failed to properly plan to obtain landowner approvals before it began construction of that project. Troubling testimony from a witness for MNSC with decades of experience in the field of utility regulation asserts that the company has an incentive to overinvest in capital, and has identified gaps in the utility’s analysis of the reasonableness and prudence of its distribution system investments. Staff and MNSC also question the company’s capitalization policies, with assurances from the company that it is following proper capitalization policies but little detailed verification.

In the discussion that follows, disputes regarding DTE’s projected net plant are discussed in sections A through J, working capital balances are addressed in section K with a summary in section L.

A. Production Plant (non-nuclear)

DTE's non-nuclear production plant historical and projected capital expenses through the test year are shown on lines 2 through 5 of Schedule B5 of Exhibit A-12, in the following categories: steam power generation, hydraulic power generation, other power generation, and MERC/fuel supply. Schedule B5.1 shows 2020 spending on these categories totaling $637 million, and projected spending in 2021 through the end of the projected test year totaling $1.3 billion. Steam, hydraulic, and other categories are subdivided into "routine" and "non-routine" subcategories, as shown in page 1 of Schedule B5.1, and non-routine steam plant expenses are further subdivided into "additions" and "removals." The references to various pages of "B5.1" below are references to Schedule B5.1 of Exhibit A-12.

In the discussion that follows, the non-routine steam plant items are discussed first in subsections 1 and 2, with line items included on page 2 of Schedule B5.1, followed in subsection 3 by a discussion of the disputed the steam plant routine items, for which individual projects over $1 million are identified on pages 4-8 of Schedule B5.1. The remaining disputed items involve non-routine projects at Ludington, discussed in subsection 4, and the "other" subcategory, discussed in subsection 5.

As a preface to the discussion, recurring issues involve whether DTE expense projections have the proper level of internal approval, and whether the company's documentation supports each project.[132] In discussing the company's generation capital planning process, Mr. Morren explained the steps involved from the initial project request form, further project development, prioritization using an internal rate of return

[132] 5 Tr 641-644.

analysis, and presentation for management review and approval. He testified that projects are approved "if they are required to meet safety and/or environmental requirements or are justified by an economic evaluation."[133] Projects costing more than $250,000 but less than $10 million are reviewed by the Capital Governance Board, which includes plant directors, the Director of Engineering, and the Senior Vice President of Energy Supply. Projects costing more than $10 million require senior corporate executive approval, while projects greater than $50 million require approval by the Finance Committee of DTE Energy's Board of Directors.[134]

In discovery, the Attorney General sought the approval status of several of the projects within energy supply. As shown in Exhibit AG-1.13, the Attorney General asked for the project approval status of projects in Schedule B5.1. DTE responded:

> All projects in A-12, Schedule B5.1 received internal budgetary approval by the Energy Supply business unit and have otherwise received any further final approvals, if required, except as follows. Project authorizations exceeding $10 million require an additional corporate level approval. Many of these projects have partial authorizations to support engineering and long lead material procurement.

DTE then explained that projects on lines 4, 5, 12, 17, 18, 19, 29, and 31 of Schedule B5.1 page 2, lines 112, and 146 on Schedule B5.1 page 6, and lines 150, 161, 181, and 197 on Schedule B5.1, page 7 are "in queue for corporate level authorizations," and provided the expected time frames for these approvals. As shown in Exhibit AG-1.14, the Attorney General recommended excluding the bridge period and test year projections for projects that have not received the corporate level authorizations. In rebuttal, in addition to objecting to Mr. Coppola's reliance on the lack of approval, Mr.

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[133] 5 Tr 642.
[134] 5 Tr 643-644.

Morren also presented additional information intended to show that approvals had been granted. Thus, he contended that Mr. Coppola had "created a standard" for funding approval:

> Witness Coppola appears to be creating a standard for approval of project funding that spans well beyond the relevant timeframe of this case. The projects included in my Exhibit A-12, Schedule B5.1, pages 2-7 have management approvals for the projects to be executed and the funding levels shown being requested in the timeframe of this case generally match the current management approvals. The attempt to pass judgement on future project funding that is not being requested in the case is misplaced and should be disregarded.[135]

And he presented Exhibit A-40, Schedule EE1, containing a response to Staff discovery in which he "updated the approval status of several of the projects identified in STDE-3.7c, indicating they had now (i.e., as of April 13, 2022) gained management approval for the funds being requested in this case."[136] He testified:

> Witness Coppola relies on discovery response STDE-3.7c [Exhibit AG-1.13] that the Company submitted on March 8, 2022 to support his conclusions. In that response, the Company indicated that several of the listed projects were scheduled to receive management approval in the spring of 2022 for the funds being requested in this case.[137]

And further:

> In follow-up discovery to the Company's STDE-3.7c response, the Company submitted discovery response STDE-12.5 (Exhibit A-40, Schedule EE1) on April 13, 2022. The STDE-12.5 discovery response *updated the approval status of several of the projects* identified in STDE-3.7c, indicating they had now (i.e., as of April 13, 2022) gained management approval for the funds being requested in this case.[138]

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[135] 5 Tr 729.
[136] 5 Tr 731.
[137] 5 Tr 731.
[138] 5 Tr 731 (emphasis added).

In her brief, the Attorney General cites an additional discovery response from the company in Exhibit AG-1.69, arguing that the company did not establish that the approvals referred to in Exhibit AG-1.13 had actually been granted:

> The response to AGDE-11.392 [Exhibit AG-1.69] contradicts Mr. Morren's rebuttal testimony that the projects in Exhibit AG-1.14 have received the prerequisite corporate approvals. The date of approval for each project in the discovery response predates the expected approval date provided in response to STDE-3.7c (included in Ex. AG1.13), with the exception of two projects. The two projects are on lines 13 and 21 of Exhibit AG-1.14. These projects were approved by the CEO and, if the Commission sees fit, can be removed from the AG's proposed disallowances for the periods shown. For the other projects, the Company's response to DR STDE-12.5 does not provide sufficient information to establish that the required approval stated in DR STDE-3.7c was obtained. Therefore, the Company has not made a convincing case that those projects should be included in rate base in this rate case and DTE's rebuttal should be disregarded. [139]

In its reply brief, DTE addressed this argument dismissively:

> DTE Electric's Initial Brief, pp 19-23, explained that the AG's proposal to disallow $166 million of capital expenditures for 13 routine and non-routine projects should be rejected because, among other things, the AG's proposal was based on an incorrect understanding of the projects' approval status. Mr. Coppola based his proposed disallowance only on a discovery response indicating when several of the projects were scheduled to receive additional internal management approvals. 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 additionally received executed capital appropriation request forms (CARFs) for the funds being requested in this case.
>
> The AG responds by contending that she asked about this further in discovery, and the "response to AGDE-11.392 [Exhibit AG-1.69] contradicts witness Morren's rebuttal testimony" that the projects received corporate approval (AG Initial Brief, p 57). To the contrary, Exhibit AG1.69 consists of a table summarizing the approved projects and attached approval documents, which confirm Mr. Morren's rebuttal testimony.

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[139] Attorney General brief, 57-58.

> The AG then acknowledges this approval and changes her position to criticize that the "date of approval for each project in the discovery response predates the expected approval date" (AG Initial Brief, p 57). This does not support any disallowance. The projects are approved, and it makes no difference that they were approved sooner than expected.[140]

While the individual line items in dispute are discussed below, it important to note that, as the Attorney General argues, many of the "approvals" cited by Mr. Morren and DTE are dated before the company's discovery response in Exhibit AG-1.13, which indicates that these "approvals" were not the expected approvals that were identified as pending in that exhibit, but were the interim approvals that already existed at the time Mr. Morren and Mr. Milo, the respondents to the interrogatory in Exhibit AG-1.13, acknowledged that additional approvals were required. In the company's post-rebuttal discovery response in Exhibit AG-1.69, moreover, the company did not fully address the Attorney General's question, which asked for "the highest level of approval received."[141] The chart provided by the company indicated only the approved amount, the person signing the approval, and the date of approval. As the discussion in certain of the individual line items shows, DTE could have provided clarity, but has instead provided confusion regarding the approvals required and approvals granted for these projects.

Also as background, several parties look at the project documentation submitted by DTE, also referred to as project initiation or PAT forms. These forms constitute a significant portion of the documentation DTE relies on to support its spending projections in this case, although DTE did not present them as exhibits in its initial filing, and particular forms are included in Staff, Attorney General, and ABATE exhibits.

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[140] DTE reply, 11-12.
[141] Exhibit AG-1.69, page 1.

1. Steam plant—non-routine additions (B5.1, page 2, lines 1-9)

Many projects in this category relate to DTE's environmental compliance obligations. As background to the disputes involving those line items, it is helpful to look at Mr. Lee's testimony. Mr. Lee reviewed the current requirements of two EPA regulations, the Steam Electric Effluent Guidelines (ELG) and Coal Combustion Residuals (CCR) regulations.

Regarding the ELG requirements, he discussed DTE's compliance strategy for both Belle River and Monroe. For Belle River, he explained that DTE would need to address bottom ash transport water (BATW) at the plant to meet more stringent limits, but has chosen the option of certifying that the units will cease operation or convert to another fuel by the end of 2028, allowing the plant to continue to operate under currently-applicable limits until then. He deferred to Mr. Morren for "pathways the Company is considering for Belle River Power Plant ELG compliance."[142] For Monroe, which must comply with effluent limits in connection with its Flue-gas Desulfurization (FGD), he explained that by agreeing to meet more stringent effluent limits than can be achieved with established "Best Available Technology," DTE would have until 2028 to achieve those more stringent limits.[143] He testified that DTE filed a notice of its intent to participate in this Voluntary Incentive Program (VIP) for Monroe.[144] Mr. Lee deferred to Mr. Morren's testimony for "the pathways the Company is considering for Monroe Power Plant ELG compliance."[145]

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[142] 7 Tr 1593.
[143] 7 Tr 1591.
[144] 7 Tr 1592.
[145] 7 Tr 1593.

Regarding the CCR requirements, he discussed the alternatives available for utilities to demonstrate compliance, testifying that DTE has indicated its plans to close St. Clair and accordingly requested an alternative closure deadline of the spring of 2022, rather than the otherwise applicable deadline of April 2021.[146] To address the Monroe Fly Ash Basin, the Belle River Bottom Ash Basins, and the Belle River Diversion Basin, he testified that DTE has submitted applications to demonstrate that these unlined surface impoundments have an alternate system that is as protective as an approved liner system. He then explained that closure of the River Rouge and Monroe Bottom Ash Basins were initiated in compliance with the CCR rule, and must be completed within 5 years, with the potential for extensions up to a total of 10 years, while three coal ash landfills (Range Road, Monroe and Sibley Quarry) may continue to receive CCR through the active life of the power plants that rely on them, and will then be closed at the end of their active life. Mr. Lee presented a summary timeline in Schedule B5.1.1 of Exhibit A-12, which has an estimate of the total cost of compliance for these provisions for each of the affected plants, as well as an estimate of the applicable timeframe. The total cost for all plants is projected to be in the range of $279-$405 million, with $26 million reflected in the 2020 historical test year.

In Case No. U-20561, the Commission acknowledged MNSC's and ABATE's concerns regarding the company's projected CCR costs. The Commission reviewed the PFD in that case, explaining:

> The ALJ recommended that the Commission adopt the MEC Coalition's proposal. The ALJ found the costs presented by DTE Electric here to be a "case in point," finding it reasonable and appropriate for the Commission

[146] 7 Tr 1594.

to begin monitoring such costs considering the substantial amounts ratepayers may be asked to foot over years to come. PFD, pp. 141-142. In further support, the ALJ stated:

> DTE proposes capital expenditures of at least $225 million to address CCR issues at Monroe alone, as shown by the preliminary estimates in Exhibit AB-8, yet did not in its direct testimony present any comprehensive overview of the projects or total project costs, only identifying the yearly spending through the projected test year in this case with minimal explanation. No timelines or cost breakdowns were presented that would indicate separately the timing and cost of engineering studies, the projected costs of construction, the required environmental approval processes, etc. In addition, a note on the closure documents for Monroe indicates that "engineering or construction pertaining to the process waste water (chem ditch) project" is excluded from the closure project scope, and is "to be addressed under a separate project."

PFD, p. 141 (footnote omitted), citing Exhibit AB-8, p. 21.[147]

After reviewing DTE's objections and arguments of the other parties, the Commission held:

> The Commission agrees with the MEC Coalition, the Attorney General, and the ALJ and finds the MEC Coalition's tracking and planning recommendation regarding CCR closure costs appropriate considering the significance and span of these requirements for the company and its ratepayers, along with the need for better transparency and a more holistic presentation of project components, costs, and timing. 9 Tr 3744-3745, 3788-3793; Exhibit MEC-54. Although DTE Electric contends this recommendation is premature, the Commission disagrees considering the company's substantial related projected expenditures requested and discussed above. In DTE Electric's next rate case, the company shall therefore 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.[148]

Mr. Lee's testimony and Schedule B5.1.1 of Exhibit A-12 appear intended to respond to the Commission's order. It must be noted, however, that nowhere in DTE's presentation

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[147] May 8, 2020 order, Case No. U-20561, page 73.
[148] May 8, 2020 order, Case No. U-20561, page 75.

does it provide any breakdown of the timing and cost of engineering studies, the projected costs of construction, the required environmental approval processes, etc., and as the discussion regarding individual line items shows, the company's other documentation does not generally provide this information either. The cost information in Schedule B5.1.1 of Exhibit A-12 does not distinguish engineering, bidding, or other phases of the work, but divides the total projected capital costs of $279-$405 million into two columns, "historical prior to 2021" and "projected 2021 and beyond." DTE did also, through Ms. Uzenski's testimony and Exhibit A-30, provide an estimate of CCR removal costs recovered through depreciation rates.[149]

Staff, the Attorney General, ABATE, and MNSC recommended adjustments to several of the line items within the category.

a. Belle River Gas Conversion Study (B5.1, page 2, line 2)

Mr. Morren described the company's projected expenditures of approximately $2.5 million in the bridge period and test year for "the engineering required to complete a detailed estimate of the performance, cost, and timeline required to convert the plant's fuel source from coal to natural gas."[150] He testified that the company consulted the original equipment manufacturer of the boiler and "determined a fuel conversion is feasible."[151] He then explained that DTE believes the fuel conversion will be a low-cost and minor adjustment that "provides an expeditious means to address potential

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149 No party addressed this exhibit but it seems to ignore that removal costs have traditionally been collected through depreciation rates prior to the use of explicit projections of those costs.
150 5 Tr 651.
151 5 Tr 651

resource adequacy and other grid reliability considerations given widespread power plant retirements across MISO Zone 7."[152]

Mr. Comings and Ms. York testified that the engineering study is premature. Ms. York reviewed the company's project document, and noted that the start and completion dates were listed as "to be determined," and concluded it is not clear DTE will actually incur the costs of this project during the bridge period or test year.[153] Mr. Comings also cited the project documentation, noting MNSC's contention that a 2026 retirement date for Belle River is more economic than a 2028 date:

> The project's documentation states:
>
> > Belle River Power Plant will cease the use of coal to generate electricity by the end of 2028. If Belle River is to continue operating beyond 2028, the plant will have to convert to a different fuel source that meets current and future emission regulations.
>
> And the stated "project objective" is that the plant will "continue to operate and generate electricity beyond 2028." But DTE has also stated that it has not yet determined whether the plant would be converted to gas, and as I have demonstrated throughout this testimony, the year that burning coal would stop at Belle River is uncertain. Thus, the project is not needed at this time, and I recommend it be disallowed for being premature.[154]

In rebuttal, Mr. Morren cited page 10 of Exhibit AB-10 to show that the company's documentation states that the "preliminary engineering work" is to be completed in 2022, and he cited additional information he presented in Schedules EE5, EE6, and EE7 to show that the engineering work was to be completed in time to support the company's 2022 IRP filing, completed in the third quarter of 2022, and under

[152] 5 Tr 651.
[153] 8 Tr 3026.
[154] 8 Tr 4069.

contract.[155] Responding to Mr. Comings, he testified that Mr. Comings misunderstood the scope of the project, that it is "not a project to do the engineering to convert the power plant to natural gas," but instead "to provide the information necessary to make the decision whether Belle River should be converted to operation on natural gas."[156] Then, he reiterated his direct testimony regarding the project scope.

In its brief, DTE relies on Mr. Morren's testimony, characterizing MNSC's objections as based on a misunderstanding.[157] It responds to Ms. York's testimony by arguing:

> 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).[158]

In its brief, ABATE relies on Ms. York's testimony, characterizing the project as premature, and discusses the project approval forms in Exhibit AB-10 at pages 12-18, arguing that it does not have any particular time frame for completing the work, and noting the construction start date and project completion dates are shown as to-be-determined.[159] In its brief, MNSC continues to challenge the company's claim that the projected study is only to determine information necessary to decide whether the plant

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[155] 5 Tr 744.
[156] 5 Tr 752.
[157] DTE brief, 35.
[158] DTE brief, 29.
[159] ABATE brief, 41-42.

should be converted. Citing cross-examination of Mr. Morren at 5 Tr 788-794, MNSC argues:

> The contention that $2.45 million in engineering is intended simply to provide cost, scope, and timeline information that is needed to decide whether to proceed with the gas conversion is questionable at best for at least three reasons. First, at hearing it became clear that much of that information has already been obtained. In particular, the engineering project involves two phases – Phase 1 was an approximately $133,000 feasibility study that was completed in 2021, and Phase 2 is a nearly $3 million engineering report and detailed cost analysis. The feasibility study provided a cost estimate, the steps that would be needed to convert the Belle River boilers to gas, and a timeline for such conversion. When asked why the information regarding cost, scope, and timeline in the feasibility study was not sufficient, Mr. Morren claimed that the feasibility study focused only on the boilers and, therefore, did not cover all of the auxiliary equipment and gas infrastructure that would be needed as part of the conversion. Witness Morren conceded, however, that the boiler is a "big piece of the conversion" and that the feasibility study provided sufficient basis for Mr. Morren to testify in his direct testimony that the conversion would be "low-cost," "minor," and "expeditious."[160]

MNSC further argues that the project scope significantly exceeds the goal of determining the economics of proceedings with a fuel conversion, citing Exhibit MEC-111 and Mr. Morren's cross-examination acknowledging receipt of a draft report totaling 750 pages, and questioning whether the final study could be evaluated by the company's planned October IRP filing date.[161]

In its reply, DTE essentially repeats its contention, arguing in a footnote that:

> 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). The project is also appropriate and timely to determine the scope, schedule, and

[160] MNSC brief, 27-28.
[161] MNSC brief, 28.

> potential cost of a potential plant conversion. This information will form important inputs to the Company's upcoming IRP (Morren, 5T 752)[162]

In its reply, Staff argues that projected expenses for this project should be approved, arguing that "arguments in favor of disallowance fail to take into account that the expenditures in the bridge period and test year are for contracted engineering work necessary for the Company to determine Belle River's future in its upcoming IRP."[163] Staff cites the company's confidential Schedule EE7 of Exhibit A-40, Mr. Morren's testimony, and Exhibit S-11.0.[164]

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

Although there was an earlier $50,000 project scheduled for 2022, shown on the form in Exhibit MEC-111, the document signed November 15, 2021, now has spending totaling $2.998 million in 2022.[165] The document states on page 2 that DTE assumes "a future resource plan includes Belle River Power Plant fuel conversion." On page 3, it states that the scope includes: "Engineering, design, procurement, project planning, scheduling, project management." Other elements of the scope listed appear to

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[162] DTE reply, 18 at n38.
[163] Staff reply, 3.
[164] Staff reply, 2-4.
[165] None of the changes on the PAT forms are dated.

encompass accomplishing the tasks. This can be seen, too, by looking at the list of what is excluded from the scope of the project:

> 1. The current high level project scope does not include the following outlined below. The scope of this project may change as project engineering develops the design for this conversion.
> 2. Conversion of the Auxiliary Boilers to natural gas.
> 3. Modifications to burn hydrogen in the Unit #1 & #2 Boilers.
> 4. Installation of a natural gas line lateral to the Belle River Power Plant (this will be performed by others under a separate project).
> 5. Installation of a gas line pressure reducing station and drying system before the gas line enters the boiler building (this work will be performed by others under a separate project).
> 6. Replacing the Primary or Secondary Air Heaters.
> 7. Automatic insertion/retraction capability of the gas burners.
> 8. Replacement of the existing burner air registers and actuators.
> 9. Removal of sootblowers from their mounting locations.
> 10. Closing the bottom ash basins under this project.

Point 4 above, for example, specifies that installation of a gas line is not part of the scope of work, because "this work will be performed by others under a separate project." Also noteworthy, Schedule EE7, while marked as a confidential exhibit, does not contain the actual contract or the name of the provider, and shows that the contract does not account for the full projected cost in the company's case.

While it is the excessive scope of this project that leads this PFD to find the funding premature, it is also worth noting that while DTE cites Schedules EE5, EE6, and EE7 of Exhibit A-40 and page 16 of Exhibit AB-10 to show that the work will be completed in 2022, the project documentation beginning at page 16 of exhibit AB-10 is the same as Exhibit MEC-111, and it clearly states: "The scope for this project may change as engineering develops the design for this project."[166]

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[166] Exhibit AB-10, page 18; Exhibit MEC-111, page 3.

b. Monroe Bottom Ash Conversion (ELG) (B5.1, page 2, line 4)

With the background of Mr. Lee's testimony discussed above, Mr. Morren explained this line item:

> Line 4 (Monroe Bottom Ash Conversion (ELG)) represents necessary engineering and long-lead material procurement for an ELG-compliant bottom ash transport system that must be completed at Monroe Power Plant by the December 31, 2025 EPA deadline. Project approval has been received for engineering and material procurement. Engineering the new system in 2022 is required in order for long lead equipment to be procured and delivered in time for construction ahead of the 2024-2025 tie-in outages on each generating unit.[167]

Consistent with his approach to these projects, Mr. Coppola recommended excluding the projected 10-month bridge and test year expenses for this project, citing DTE's discovery response in Exhibit AG-1.13 to show that the project did not have corporate approval and such approval was not expected until the fall of 2022.[168]

Ms. Champion addressed this project for Staff, citing Exhibits S-10.5 and S-11.4 and testifying that the project has only partial approval.[169] She also explained Staff's review of the company's actual expenditures to date on this project:

> Over the 22-month bridge period, the Company projected to spend $16,946,944 for the Monroe Bottom Ash Conversion project. Staff Exhibit S-10.4 shows the 15 months of actuals and 7 months of updated cost projections totaling $8,009,019. Compared to the amount of $16,946,944 originally requested in the bridge period, this is an over-projection of $8,937,925, or 53%.[170]

Staff recommended holding projected bridge period expenditures to the updated projection, a reduction of $8,937,925. For the test year, Ms. Champion explained that Staff considered the degree of overprojection in the company's filing for the bridge

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[167] 5 Tr 652.
[168] 8 Tr 4779.
[169] 8 Tr 5329.
[170] 8 Tr 5328.

period, 53% as noted above, and recommended a 50% reduction to the test year projection.[171]

Ms. York recommended a disallowance of the projected bridge and test year costs for this project, citing Exhibit AB-10, pages 19-22 in explaining her recommendation:

> DTE's supporting document, PMP 15134 REV 2, for this project indicates that the project is not expected to be in service until over two years after the end of the projected test year in this case. Indeed, the revised version of PMP 15134 states that conversion to dry handling or a high recycling system is required no later than December 21, 2025. Therefore, it is not clear whether DTE will actually incur any costs associated with this project during the bridge period or projected test year in this case.[172]

In rebuttal, Mr. Morren objected to the Attorney General's recommended exclusion of bridge and test period costs, citing his direct testimony indicating that engineering and long-lead material procurement had been authorized by the DTE board, and further objecting to any limitation on the company's projections based on corporate approval, as discussed above.[173] He did acknowledge, citing Schedule EE1 of Exhibit A-40, that the board approval was for a total of $18.9 million, consistent with Ms. Champion's testimony at 8 Tr 5329. In response to Ms. York, in addition to expounding on the importance of the work, he explained the work for this project would proceed by unit. He testified that work is already underway at the first unit, and cited the project document PMP 15134 Pat 1 Rev 2 included in Exhibit AB-10 at page 22.[174]

In its briefs, DTE reviews Mr. Morren's testimony, including his rebuttal testimony explaining the company's objections to Mr. Coppola's and Ms. York's recommendations.

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[171] 8 Tr 5329.
[172] 8 Tr 3027.
[173] 5 Tr 733.
[174] 5 Tr 744-746.

DTE did not address Staff's recommendation.[175] In its brief, Staff recommends that the Commission adopt its recommendations as explained by Ms. Champion.[176] In her brief, the Attorney General cites an additional discovery response from the company in Exhibit AG-1.69, arguing that the company did not establish that the approvals referred to in Exhibit AG-1.13 had actually been granted.[177] ABATE similarly cites Ms. York's testimony, arguing that DTE has not established that it will actually incur the costs in the bridge or test year.[178]

While this PFD finds Staff's recommendation to be a reasonable alternative, this PFD concludes that DTE has not established that it will spend any additional money on this project in the 10-month bridge period of 2022 or in the test year, i.e. anything beyond its existing 2020 and 2021 expenditures. This PFD's review of the documentation offered in support of this project shows that the only approved spending was for 2020 and 2021 as shown in Exhibit AG-1.69, page 3. This approval document—with a signature dated December 21, 2020—is clearly not the "full authorization expected Fall 2022" that Mr. Morren acknowledged was pending in Exhibit AG-1.13. Instead, this is the approval form for the "engineering and material procurement" Mr. Morren referred to, but for 2020 and 2021 rather than 2022 and 2023.

While Mr. Morren's rebuttal and his discovery responses in Exhibits A-40, Schedule EE1 and AG-1.69, page 2, claim that additional approval was granted for spending of $18.9 million—which he connects on page 2 of Exhibit AG-1.69 with DTE's 2022-October 2023 spending projection of $15.1 million—the approval provided was

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[175] DTE brief, 27-31; also see DTE reply, 14-16.
[176] Staff brief, 8-10.
[177] Attorney General brief, 57-58; also see Attorney General reply, 8-9.
[178] ABATE brief, 42-43; ABATE reply, 11.

signed in December 2020 and covered spending only for 2020 and 2021. Although DTE reports spending of only $11.9 million of that amount for 2020 and 2021, no additional project approval was offered for the later time period, and DTE made no effort to distinguish the work covered by the 2020 and 2021 spending relative to its 2022-2023 projections.[179] DTE attempts to rely on the PAT form in Exhibit AB-10, page 22 and in Exhibit S-11.6, but that form containing a $97 million expense projection has not received corporate approval, as Mr. Morren acknowledged in Exhibit AG-1.13. This PFD therefore finds that the 10-month bridge and test year projections for this project should be excluded from rate base.[180]

c. Monroe FGD Wastewater (ELG) (B5.1, page 2, line 5)

Mr. Morren identified the motivation for the project:

> Monroe Power Plant is required to comply with the FGD wastewater-portion of the ELG Rule by the end of 2025, unless the Company participates in the Voluntary Incentives Program (VIP) contained in the ELG Rule. The VIP allows compliance to be achieved by the end of 2028 if the Company agrees to meet more stringent FGD wastewater effluent limitations. The Company filed a VIP NOPP in October 2021, allowing it to evaluate alternative compliance technologies.[181]

He stated that the projected expenses on this line are for engineering to develop a compliant system, and that the company "will test and evaluate alternative technologies that best meet the needs of the site-specific wastewater streams" at Monroe.[182] Mr. Coppola identified this as one of the projects lacking full DTE approval, citing Exhibit

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[179] Ms. Champion's testimony and Exhibit S-10.4 further shows that DTE will not in fact spend the projected bridge period total of $16.9 million in that timeframe, but will instead spend approximately $8 million, which is that the approximate amount Schedule B5.1, page 2, line 4 forecasts for 2021 spending.
[180] Although DTE did not spend the amount shown on Schedule B5.1, page 2, line 4, the company's updated forecast for actual 2021 and the first 10-months of 2022 is equivalent to the reported 2021 value, so this PFD sees no need to adjust the 2021 spending to reflect actual spending.
[181] 5 Tr 647.
[182] 5 Tr 652.

AG-1.13 to show that approval was not expected until sometime beyond 2022. In rebuttal, Mr. Morren cited DTE's response to Staff discovery in Schedule EE1 of Exhibit A-40 to show that this project "has approval to proceed for $3.7 million of work compared to a rate case projection of $3.5 million."[183]

In its brief, DTE relies on Mr. Morren's testimony on this issue.[184] As discussed above, the Attorney General takes issue with Mr. Morren's assertion that DTE approved the projects as contemplated in Exhibit AG-1.13, since the approvals Mr. Morren relied on had already been issued at the time DTE answered that discovery response. The Attorney General cites the documents in Exhibit AG-1.69 to support her position.[185]

This PFD finds that the 10-month bridge period and test year projected expenditures for this project should be rejected. While DTE does appear to have approved additional spending beyond 2021, the project document in Exhibit AG-1.69 shows that spending is "to perform engineering for the technology that is selected to meet compliance." Mr. Morren testified that the spending in this case was to test and evaluate alternative technologies that best meet the needs of the site-specific wastewater streams at Monroe. The scope of work he described is consistent with the first page of the approval documentation in Exhibit AG-1.69, page 5, which authorized spending of $1.7 million in 2020 and 2021, and indicated that project along with an EPRI study, would enable to the company to determine the best available technology to meet the effluent guidelines. While there is a project approval form with a signature

[183] 5 Tr 733.
[184] DTE brief, 19-21, 27-31; also see DTE reply, 14-16.
[185] Attorney General brief, 56-58.

dated November 15, 2021,[186] this approval would have been granted well before DTE indicated in Exhibit AG-1.13 that "full authorization expected beyond 2022." In addition, the record does not establish that DTE has selected the technology to be employed, and thus has not established when the funds referenced in that form will be spent. Instead, it appears DTE is taking the time to evaluate its options, consistent with the Voluntary Incentive Program (VIP) Notice of Planned Participation (NOPP) that Mr. Morren referenced in his direct testimony.

d. Sibley Quarry Landfill Modification ((B5.1, page 2, line 8)

Mr. Morren testified that the projected bridge period spending of $21.8 million and test year spending of $2.3 million include the costs associated with expanding the capacity at the Sibley Quarry Landfill to accept additional CCR material to be removed from Monroe Power Plant: "The project will focus on improvements to material handling at the site, including road improvements, a new conveyor system, replacement of discharge piping, and a new operations fill plan."[187]

Ms. York recommended the disallowance of the bridge period and test year costs for this project based on her review of the project documents included in Exhibit AB-10:

> As shown in the planning documents provided by DTE, specifically PMP 15871, 15872, 15873, the landfill modification is estimated to be complete on or before August 31, 2025. DTE's project documents show several projects associated with the landfill modification, and indicate that some projects were expected to be complete in 2021, while the most expensive ones are expected to be complete by August 31, 2025.
>
> DTE has not provided any details about the status of these projects, the amount of costs actually incurred so far, and whether any of the projects planned for 2021 were indeed completed in 2021 as expected. Therefore,

[186] Exhibit AG-1.69, page 6.
[187] 5 Tr 653-654.

> there is no evidence that DTE has or will complete any of these projects during the bridge period or projected test year in this case.[188]

She further explained:

> The landfill modification is not expected to be complete until August 31, 2025, and therefore will not become used and useful during the bridge period or projected test year in this case. In addition, DTE has not provided evidence to show that it has been completing the various projects identified in its PMP documents in accordance with the scheduled timeline prior to 2025. Without such information, the costs of a project that will not be placed in service until two years after the projected test year should not be included in customer rates.[189]

In rebuttal, Mr. Morren testified that the spending included in the project documents does support the company's projections.[190] DTE relies on Mr. Morren's rebuttal testimony and Exhibit AB-10 in its brief, arguing:

> 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).[191]

ABATE's brief focuses on Ms. York's concern that the company has not provided adequate support for the expenditures, as well her concern that the project would not be complete within the test year:

> The Company did not provide adequate details regarding the status of these various projects, the costs actually incurred so far, or whether any of the projects planned for 2021 were indeed completed as expected and forecast. In addition, it appears DTE has revised the amounts in its PAT forms to tie them to the capital expenditures included in its rate case exhibits prior to its rate case filing. This appears to include the 2020 amounts, which have increased from originally budgeted and forecasted

[188] 7 Tr 3028.
[189] 7 Tr 3028-3029.
[190] 5 Tr 746-747.
[191] DTE brief, 39; also see DTE reply, 20.

> amounts. As such, there is insufficient evidence that DTE has or will complete any of these projects during the bridge period or projected test year in this case and their associated costs are not certain.[192]

This PFD finds that DTE has not supported the specific costs it will incur during the bridge and test year for this compilation of projects. DTE provided a disorganized set of project forms, with three project numbers for the landfill expansion, and multiple revisions, as is clear from the documents in Exhibit AB-10, pages 24-34 and in the chart Mr. Morren presented at 5 Tr 747. Pages 24 and 25 show that these three projects are linked into a single "Fossil Generation Large Capital Projects Charter" with the Monroe bottom ash basin conversion, which as discussed above has not proceeded as projected in DTE's filing, Schedule B5.1, line 4. As Ms. York testified, there are conflicting project dates for the three identified projects. The forms cited by Mr. Morren in his chart at 5 Tr 747 are at pages 26, 30, and 34 of Exhibit AB-10. Page 26 includes "engineering, procurement and construction" for four listed items: standpipe well, chimney drain, sump pump system, and operations (fill) plan design. It lists a project start date as December 16, 2019, a construction start date of July 6, 2020, and a project in-service date of August 31, 2025. Consistent with Ms. York's testimony, nothing in this document explains how the various expense projections for the years 2020 through 2024 shown on this exhibit relate to the accomplishment of any of those components (engineering, procurement, construction) for any of the four items listed. Page 23, which appears to be an earlier version of this project document, lists as the project scope to "perform engineering for the following components," citing the same four identified above, at a total cost of $387,891 compared to the total cost of $21.14 million shown on

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[192] ABATE brief, 44 (citations omitted); also see ABATE reply, 13.

page 26, not including contingency. Looking at page 30, the project scope is stated as: "Perform engineering for installation of a material handling conveyor at Sibley Quarry to convey ash from a designated truck unloading area to the bottom of the quarry." And the total project cost is shown as $6.08 million. The project start date is December 16, 2019, a construction start date of July 6, 2020 is stated, and the in-service date shown is August 31, 2025. What appears to be an earlier version of this project document at page 27 has the same project scope, but reports a total cost of $172,000. The project start date was December 16, 2019, the construction start date was August 17, 2020, and the project in-service date was shown as June 28, 2021. Nothing in the project documents or DTE's testimony reconciles the change from the earlier version to the next, including the change in cost and the changes in construction start and completion dates. Nothing indicates whether work is under contract, whether any contract was competitively bid, or any other basis for the cost projections. While the company asserted the need to expand the landfill capacity, the supporting documents it cites do not provide support for specific expenditures or the timing of those expenditures, or provide a basis to conclude that the costs are reasonable and prudent.

2. Steam plant—non-routine removals (B5.1, page 2, lines 10-21)

In the category of "non-routine removals," DTE is projecting bridge and test year capital expenditures of approximately $186 million. Mr. Morren addressed each of the line items in this section briefly, also referencing Mr. Lee's testimony regarding the company's obligations to address coal combustion residuals (CCR).

Staff, the Attorney General, ABATE, and MNSC witnesses raised some general concerns with the company's projections. As discussed below, Staff raised a concern regarding the overlap with the company's request to recover the cost of removal through rate case rate base projections when the Commission's depreciation orders provide a process for recovering these costs. (Staff's concerns are discussed below in subsection a.) The Attorney General's objections to the company's projections in this category focus on the lack of DTE corporate approval of projects in certain line items, citing the same discovery responses discussed above. ABATE reviewed project scoping documents and raised objections to specific line items as inconsistent with those project scoping documents. While Mr. Comings also addressed capital expenditures for Monroe, MNSC's brief focuses on the company's projected capital expenditures at Belle River, given the potential retirement of Belle River, and does not seek expense adjustments related to Monroe.

a. Cost of removal as a depreciation case issue

Several Staff witnesses addressed the company's projected costs of removal in lines 10-21 of Schedule B5.1, page 2. Mr. DeCooman testified that the company collects a portion of depreciation expense in base rates for the cost of removal, which gets recorded to the depreciation reserve for each class of asset at a rate set through depreciation case filings.[193] He cited a DTE response to Staff discovery in Exhibit S-10.1 in explaining that the capital expenditures for these removal projects are charged against the accumulated depreciation reserve account, thus increasing rate base.[194] He further cited that discovery response in testifying that the company is not currently

[193] 8 Tr 5299.
[194] 8 Tr 5299-5300.

collecting a full return of the capital expenditures for removal projects requested in this case through depreciation rates:

> As explained on page 2 of Exhibit S-10.1, the full costs of the removal projects are not included in depreciation rates. Case No. U-16117 included removal cost estimates for demolition/dismantlement only. Decommissioning expenses requested in Case No. U-18150 were not approved for Tier 2 units, and the depreciation rates were held at the level previously established in Case No. U-16117. Page 3 of Exhibit S-10.1 identifies the amounts for removal projects approved for inclusion in depreciation rates, and page 4 of Exhibit S-10.1 identifies the amounts for removal projects requested but not approved for inclusion in depreciation rates.[195]

He then explained that Staff recommended removing from rate base in this case the capital expenses for the removal projects that were not previously approved for inclusion in depreciation rates, citing a settlement agreement approved in Case No. U-18150:

> The Commission had previously approved a settlement agreement in Case No. U-18150 that stipulated "maintaining existing depreciation rates from the U-16117 Order for DTE Electric's Tier 2 plants, (iv) requiring future removal costs for the Tier 2 Plants, when the removal costs are incurred, to be reconciled after firm removal cost bids are accepted and reviewed by Staff and ABATE." The Company confirmed in a response to Staff discovery that such a review has not taken place. As the Company has not performed such a review with Staff and ABATE, and considering that setting depreciation rates to reflect the full cost of removal projects for Tier 2 generating facilities would be accomplished in a future depreciation case, Staff is recommending this adjustment to align the inclusion of the capital expenditures for removal projects in rate base with what has been approved in depreciation cases. Staff is recommending that these costs be removed from rate base until the Commission and parties are given the opportunity to review and determine the appropriate decommissioning expenses for each facility in a future case and these costs are reflected in depreciation rates. Until that time, Staff is recommending that recovery of the capital expenditures for removal projects be deferred, and that the Company collect a carrying charge on these costs (see the testimony of Staff witness Bob Nichols for more details on this accounting treatment).

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[195] 8 Tr 5300.

> Staff witness James LaPan supports a recommendation for the appropriate review of the costs prior to their inclusion in base rates.[196]

Mr. Nichols also provided an explanation of Staff's recommended deferral:

> The normal mechanics of COR accounting that make a utility whole for the carrying cost results in an increased rate base when COR is actually spent. Pre-collected COR reduces rate base for dollars the utility has received but not yet spent, but the utility is made whole because it may use those pre-collected ratepayer-supplied funds for its operations. Actual COR spend increases rate base from the reduced amounts that were recorded by the pre-collected COR as those amounts are actually spent. To the extent that the COR actual spend is reasonable and prudent, but deferred for review, the Company should receive a full return on the deferred amount in order to be made whole for the carrying cost. To the extent that the actual COR spend has not been pre-collected in rates, then it has been funded by the investor (utility), and it should also receive a full return on if it was reasonably and prudently incurred.[197]

Mr. LaPan testified:

> Typically, the retirement, closure, and decommissioning plans for plant in service, and their supporting cost estimates, are fully vetted within a depreciation rate case. A depreciation case provides the Staff and intervenors the opportunity to review the estimated costs for retirement of depreciated plant as well as the Company's proposed methodologies for decommissioning, for reasonable and prudence. In the current case, the Company has identified costs already, or projected to be, incurred due to certain retirements.[198]

He stated that the costs of removal or retirement were "not subject to review" in the company's most recent depreciation case,[199] Case No. U-18150, and cited the settlement agreement entered into in that case:

> That settlement agreement obligates the Company to provide Staff and ABATE the opportunity to reconcile costs associated with plant

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[196] 8 Tr 5302.
[197] 8 Tr 5037.
[198] 8 Tr 5517-5518.
[199] As a matter of fact, this is not technically correct. The cost of removal was "subject to review" in Case No. U-18150, as shown by a review of the company's November 1, 2016 application or the April 17, 2018 Proposal for Decision issued in that case; this PFD assumes that Mr. LePan meant that the settlement agreement did not revise the removal cost estimates that were used in Case No. .U-16117.

retirements. This is to occur immediately following the acceptance of firm removal bids. However, neither Staff nor ABATE were provided this opportunity.[200]

Mr. LaPan referenced Staff's recommended removal of retirement costs with deferred accounting, and testified that Staff also recommends that the Commission not allow DTE to recover these specific amounts in rates "until the Company complies with the Commission's Order in U-18150," further explaining: "After DTE has provided Staff and ABATE opportunity to review and reconcile the costs DTE should resubmit their recovery request in a subsequent rate case."[201]

In rebuttal, Ms. Crozier addressed the settlement agreement in U-18150:

> The settlement agreement provided for a requirement to provide removal cost bids for the Tier 2 plants. Specifically: "(iv) require future removal costs for the Tier 2 Plants, when the removal costs are incurred, to be reconciled after firm removal cost bids are accepted and reviewed by Staff and ABATE" (December 6, 2018 Order in Case No. U-18150, Exhibit A, Page 2, Paragraph 5). Therefore, it should be noted that any discussion regarding the agreement by the parties in the Settlement Agreement, from Case No. U-18150, to reconcile future plant removal costs must be limited to the Company's Tier 2 plants. To do otherwise would inappropriately and retroactively modify the Case No. U-18150 Settlement Agreement without either, the Company's agreement, or the Commission's approval.[202]

She testified that DTE would provide a copy of removal cost bids for the Tier 2 plants to Staff and ABATE "after those bids have been vetted and accepted by the Company." She stated her view that the settlement agreement does not preclude the company from including projected removal costs in this proceeding, characterizing the settlement agreement as follows:

> The referenced provision of the settlement agreement was intended to facilitate a transparent exchange of information by providing Staff and

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[200] 8 Tr 5518.
[201] 8 Tr 5519.
[202] 7 Tr 2376-2377.

> ABATE the opportunity to reconcile *incurred removal costs* against firm *removal cost bids* for the Tier 2 plants. Again, this reconciliation process is for Tier 2 plant removal costs only. However, Staff has apparently taken this provision and expanded its scope and meaning 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. Moreover, Staff appears to have expanded this reconciliation process to include Tier 1 (Belle River and Monroe) and other plants, which was never agreed to (or ordered) in the Case No. U-18150 settlement.
>
> Specifically, the provision requiring the submittal of firm removal cost bids is specific to Tier 2 plants, which the settlement agreement (Appendix A, Page 2, paragraph 5) defined as “Trenton Channel, St. Clair and River Rouge”. Therefore, insomuch as Staff’s disallowance of costs is predicated on the need to first provide Tier 2 cost bids for review, then the costs for the Monroe Bottom Ash Basin Closure and the Conners Creek Decommissioning / Sea Wall projects should not be included in Staff’s proposed disallowance.
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> Further, the settlement agreement (Appendix A, Page 3, paragraph 5) states “In light of the proposed depreciation rates reflected in this Settlement Agreement and the associated delay in recovery of plant costs associated with DTE Electric’s Tier 2 coal plants, *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 or other forms of recovery*.” (emphasis added)[203]

Ms. Crozier described the treatment of removal cost estimates in depreciate rates, citing Ms. Uzenski’s testimony, testifying that estimated removal costs are reflected in depreciation rates and accrued over the life of the asset, while “[a]ctual removal costs are charged against that accrual as they are incurred.” She testified that because the projected test year in this case is a forecast of the expenditures “that are likely to be made based on the information known at the time of the rate case filing,” she asserted that the forecast “should be evaluated on a standard of reasonableness and prudence, not on a simple comparison to dated cost estimates from a different

[203] 7 Tr 2377-2378.

proceeding."[204] She then testified that no Staff witness testified that the company's projected costs were imprudent or unreasonable.[205] She further contended that Staff "has created a new regulatory and ratemaking standard that removal cost amounts can only be set in a depreciation case, and any amounts projected in a general rate case above that previously estimated level should be removed and deferred."[206] She objected, too, that "there could be a multi-year gap in time between an order in a depreciation case establishing projected removal cost levels, and the inclusion of those costs in a general rate case," contending that Staff's recommendation "results in an unjust and unreasonable regulatory lag."[207]

Citing Ms. Crozier's testimony, Ms. Uzenski addressed Staff's deferred accounting proposal:

> The proposal is inconsistent with utility plant accounting. Normally, estimated removal costs are reflected in depreciation rates and accrued over the life of the asset. Actual removal costs are charged against that accrual as they are incurred. Any over or under accrual is handled by updating depreciation rates in depreciation cases and applying the new depreciation rates prospectively when they are reflected in base rates. Therefore, as supported by Company Witness Crozier in her rebuttal testimony starting at page AFC Rebuttal-3, the Commission should approve the costs in rate base in the instant case.[208]

Asserting that under Staff's proposal, DTE "will not be able to recognize the equity return in net income for SEC purposes until recovery in rates is provided," she offered an alternative to Staff's proposal that the company would "include the costs in rates in

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[204] 7 Tr 2378-2379.
[205] 7 Tr 2379.
[206] 7 Tr 2379.
[207] 7 Tr 2379.
[208] 7 Tr 2789.

the instant case, but subject to refund . . . should any actual expenditures ultimately be found to be imprudent and permanently disallowed."[209]

In its brief, Staff stood by its recommendation in part,[210] also expressing willingness to adopt DTE's proposed alternative, with the following condition:

> The Company will provide detailed cost information in its next depreciation case comparing the actual project scope and costs to the previously approved project scope and costs. Any actual costs found to be unreasonable or imprudent shall be written-off and a regulatory liability for the "return on" the costs shall be included in base rates for refund to customers.[211]

In its reply brief, DTE agreed to Staff's condition, asserting: "The Company agrees, so this matter is resolved for purposes of this case."[212] Based on this agreement, Staff's objections to the expense projections on lines 11, 16, 17, and 19 of Schedule B5.1 are deemed resolved.

This PFD notes, however, that Staff's analysis and the company's arguments in response have brought to light some confusion regarding the company's recovery of removal costs. As noted above, Ms. Uzenski explained the traditional depreciation accounting as follows:

> Q81. How does DTE Electric account for the plant retirements?
>
> A81. The original cost is credited out of plant in service and debited to accumulated depreciation. This treatment is prescribed by the Uniform System of Accounts Electric Plant Instruction number 10 (F) which states, "The book cost less net salvage of depreciable electric plant retired shall be charged in its entirety to Account 108, Accumulated provision for depreciation and amortization."[213]

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[209] 7 Tr 2789.
[210] See Staff brief, 11-14.
[211] Staff brief, 14.
[212] DTE reply, 14.
[213] 7 Tr 2718.

When the magnitude of the accumulated provision for depreciation is decreased, it has the effect of increasing rate base. But the utility does not earn its cost of capital on the retired plant or removal costs at that point, and the removal costs are not depreciable; technically, through the reduction in accumulated depreciation, the utility has received a full return of its investment. Staff treats the removal costs as related to the accumulated provision for depreciation and adjusts it accordingly. The Attorney General, who also recommended adjustments to certain of the removal costs as discussed below, treated the removal costs as additions to total plant, and also adjusted depreciation expense accordingly. DTE did not address this discrepancy in its rebuttal. Staff's approach to reflecting the impacts of removal costs in rates appears to be correct.

While DTE has at least some line-item detail for its projected capital expenditures in this case, including identifying by project name plant additions of more than $1 million for generating projects, this PFD notes that does not have corresponding detail for its projected provision for accumulated depreciation. Ms. Uzenski presented schedules showing DTE's adjustment to 2020 plant and accumulated depreciation balances to reflect items such as the 2021 retirement of Rouge River. There is no schedule showing the adjustments to 2020 accumulated depreciation to derive the test year projected value. Ms. Uzenski testified to almost $1 billion ($937.5 million) in projected removals charged to accumulated depreciation:

> The decrease in depreciation reserve on line 8 from December 2020 to October 2022 of $699.8 million is due to $1,857.1 million of depreciation expense offset by $577.6 million of removal costs and $1,979.2 million of plant retirements. The increase of $308.9 million from October 2022 to October 2023 represents depreciation expense of $1,079.6 million partially

> offset by $356.9 million of removal costs and $413.7 million of plant retirements.[214]

Given the confusion on this record regarding DTE's treatment of the past and projected removal costs presented in this case, this PFD recommends that the Commission require DTE to include a schedule detailing the company's removal-cost-related adjustments to the accumulated provision for depreciation in future rate cases. Of course, as the discussion regarding the distribution system capital expenditures shows, there are presumptively several categories of routine removals that DTE has forecast in that approximately $1 billion removal amount, but the additional transparency may avoid unnecessary confusion.

In that regard, this PFD notes that both Staff and DTE discussed the settlement agreement in Case No. U-18150, and in particular the following two paragraphs:

> 5. The Parties request that the Commission enter an order (i) increasing DTE Electric depreciation rates and associated depreciation expense by a total of approximately $90 million based on depreciation rates designed by DTE electric to accomplish the $90 million depreciation expense increase, see Attachment A, (ii) requiring DTE Electric Tier 2 power plants (i.e. Trenton Channel, St. Clair and River Rouge) (hereinafter the "Tier 2 Plants") to maintain specific, non-group, individual power plan accounts for remaining investment and depreciation purposes, (iii) maintaining existing depreciation rates from the U-16117 Order for DTE Electric's Tier 2 plants, (iv) requiring future removal costs for the Tier 2 Plants, when the removal costs are incurred, to be reconciled after firm removal cost bids are accepted and reviewed by Staff and ABATE, (v) deferring inclusion in depreciation rates of removal costs for DTE Electric's Conner's Creek and Harbor Beach power plants until removal costs are actually incurred, (vi) authorizing amortization in lieu of depreciation for General Plant Account 397 Communication Equipment, (vii) authorizing the MERC deprecation rate of 4.05%, (vii) concluding that DTE Electric has complained with all requirements of the U-16117 Order and the U-16991 Order, (ix) approving the effectiveness of the depreciation rates, terms and conditions of an order approving this Settlement Agreement upon the effective date new

[214] 7 Tr 2743.

> retail electric rates pursuant to a final order in DTE Electric's general rate case, Case No. U-20162, and (x) approving a requirement for DTE Electric to file a new deprecation case no later than December of 2024 based on plant balances as for December 31, 2023.
>
> 6. In light of the proposed depreciation rates reflected in this Settlement Agreement and the associated delay in recovery of plant costs associated with DTE Electric's Tier 2 coal plants, 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 or other forms of recovery. DTE Electric agrees to seek recovery of the remaining net book value associated with its Tier 2 coal plants through securitization after the Tier 2 coal plants are retired if this is the lowest cost option for ratepayers. Other options to be evaluated include traditional depreciation, regulatory asset amortization in base rates, or other forms of ratemaking or regulatory relief.[215]

Ms. Crozier seemed to contend in her testimony that because the settlement agreement only addressed Tier 2 plants, DTE has no obligation to provide bids for removal costs for other plants.[216] Whatever the parties to that settlement agreement intended, it cannot be interpreted to protect DTE from having to support its accounting for removal costs when it relies on those removal costs to increase rate base in a rate case.

Finally, that DTE and Staff have resolved their dispute regarding DTE's ability to project removal costs does not resolve the disputes regarding the company's projections raised by the Attorney General and ABATE, which are addressed in the following sections.

b. Monroe Bottom Ash Basin Closure (CCR) (B5.1, page 2, line 11)

Regarding the projected 22-month bridge period expenditures of $37.1 million and test year expenditures of $20.2 million for the Monroe Bottom Ash Basin closure, Mr. Morren testified:

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[215] December 6, 2018 order, Case No. U-18150, Exhibit A, pages 2-3.
[216] 7 Tr 2377-2378.

> This project includes the removal of approximately 1 million cubic yards of bottom ash from the Monroe inactive bottom ash basin and its transportation to Sibley Quarry. The project received Company BOD approval in December 2019. The final CCR Rule requires closure to be initiated as soon as technically feasible, but no later than April 11, 2021 and completion of the closure within five years. Closure was initiated on October 21, 2020. Company Witness Lee describes the Company's closure plans for CCR sites in further detail.[217]

Ms. York testified that the projected bridge and test year spending should not be approved because the project would not be completed until 2025, also citing a lack of support for the projected expenditures in DTE's project documents included in Exhibit AB-10, pages 35-38:

> While DTE's planning documents show various activities associated with these projects planned for 2018 through 2024, with timelines updated periodically, DTE has not provided an explanation of what it has actually accomplished to date, in the process of moving toward closure by August 31, 2025. Nor has DTE provided information on actual expenditures to date associated with this project. Therefore, it is not clear what portion of costs associated with this project can reasonably be expected to be incurred during the bridge period or future test year in this case. In addition, extensions are available under certain circumstances. DTE has not indicated whether it has requested an extension, or explored this option.[218]

She explained her primary recommendation to disallow all projected capital expenditures associated with the project, since it would not be complete until well after the test year, "and the lack of evidence suggesting that DTE is sticking to its anticipated timelines associated with the closure by August 31, 2025."[219] If the Commission finds that some level of capital expenditures for this project is appropriate, she then recommended that the Commission ensure that the amounts included in rates are tied to the planning documents.

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[217] 5 Tr 654.
[218] 8 Tr 3030.
[219] 8 Tr 3030.

In his rebuttal testimony, Mr. Morren testified that the workpapers Ms. York cited, Exhibit AB-10, pages 35-38, show the project being executed and the funding being utilized:

> Her concerns can be directly resolved by a review of PMP 15870 PAT2 REV3 (included in her Exhibit AB-10). This document shows substantial work has been completed and done so in a logical pattern for this type of major project. There is up front work of lower intensity followed by multiple periods of heavy activity, followed by project demobilization activities.[220]

In its briefs, DTE relies on Mr. Morren's rebuttal testimony.[221] ABATE cites Ms. York's testimony, and argues that DTE provided the identified pages of Exhibit AB-10.

This PFD finds that DTE has not established that it is proposing reasonable and prudent expenditures that will actually be made as projected. PMP 15780 PAT2 REV 3, cited by Mr. Morren, is page 38 of Exhibit AB-10. His assertion that this form "shows substantial work has been completed and done so in a logical pattern" is demonstrably untrue from a review of the form. There is no breakdown of the projected $63 million in total expenditures shown on that form ($91.8 million with contingency) for engineering or any specific stage of construction.The project scope and objective still refer to "engineering" although an earlier version of the form, page 35 of Exhibit AB-10, showed a "60% engineering" cost estimate of $813,000 to be completed in 2020.[222] As noted above, in Case No. U-20561, the Commission provided DTE with an opportunity and the direction to detail these projected expenditures. It is not enough that the project is

[220] 5 Tr 748.
[221] DTE brief, 39; DTE reply 20-21.
[222] The project scope summary states: perform the following *engineering deliverables* for Closure-by-Removal of the Monroe BA Basin. To include (but not limited to): 1. Site geotechnical investigation and surveying 2. Determination and design of removal method 3. Material dewatering method 4 Logistics requirements and design; 5 Project scope development." Under "PMP Problem Description & Project Objective" the objective is stated as follows: "Perform *engineering* and determine an effective means to pursue Closure-by-Removal of the BA Basin that would serve to maintain environmental compliance." (emphasis added).

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

c. Monroe Fly Ash Basin Closure (B5.1, page 2, line 12)

As shown in Schedule B5.1, DTE is projecting expenditures of $667,000 in the bridge period and $966,000 in the test year for engineering work on a plan to close the Monroe Fly Ash Basin. Mr. Morren testified:

> Line 12 (Monroe Fly Ash Basin Closure (CCR)) represents a project to begin the engineering for closure of the fly ash basin. Once the Monroe Fly Ash Basin ceases receipt of CCR material, which is required by December 31, 2023, basin closure must be initiated within 30 days and completion of the closure is required within 5 years (with the opportunity for up to five 2-year extensions if necessary) per the final CCR Rule.[223]

This project reflects one of the items Mr. Coppola recommended a disallowance for, due to lack of complete project approval. In response, Mr. Morren cited management approval for $1.8 million of work as shown in Schedule EE1 of Exhibit A-40.[224] In its

[223] 5 Tr 654.
[224] 5 Tr 733-734.

brief, DTE relies on Mr. Morren's rebuttal testimony and exhibit.[225] The Attorney General cites Exhibit AG-1.69 to show that DTE has not obtained any new approvals since it submitted the response to the Attorney General's discovery in Exhibit AG-1.13.[226]

While this PFD agrees with the Attorney General's assessment that no new approvals were granted for this project, it appears from the company's description of its approval process that no additional approvals are required for this project. The two PAT forms in Exhibit AG-1.69, pages 7 and 8, show that the projected work is for engineering studies, with approval for $800,000 in 2022 and $999,760 in 2023. As the 2023 project form states, the project is to "provide input into development of a closure strategy." No one has contended that this study cannot be capitalized but should be expensed. The actual spending in Exhibit S-10.4 shows spending for 2022 roughly equal to the projected amount. Therefore, this PFD finds that it is reasonable to include the funding in rate base.

d. River Rouge, St. Clair, and Trenton Channel Decommissioning (B5.1, page 2, lines 17-19)

Line items 15-19 on Schedule B5.1, page 2, project decommissioning costs for retired plants. Mr. Morren discussed the projected expenditures on lines 15-19 of Exhibit A-12, Schedule B5.1, page 2, as follows:

> Lines 15-19 detail steam plant removal costs associated with the retirement and decommissioning of power generation assets at Harbor Beach, Conners Creek, River Rouge, St. Clair, and Trenton Channel Power Plants. Removal of retired steam generating units involves three primary activities: decommissioning, decontamination, and demolition. Decommissioning activities include the cost to isolate all unit systems and equipment to prepare them for removal from the site.

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225 DTE brief, 20-21.
226 Attorney General brief, 56-58.

> This includes electrical, mechanical, plant controls, water and gas service shutdown, and disconnection from the transmission system. Decontamination includes disposing of hazardous materials (including draining oils, chemicals, and other fluids), cleaning tanks and pipelines, and removing batteries. Demolition includes tearing down buildings, removing and remediating the coal pile, asbestos abatement, and remediating ash basins and ponds.[227]

Lines 17-19 are the only line items in dispute. For River Rouge (line 17), DTE projects 2021 spending of $3.38 million, 10-month bridge period spending of $10.44 million, and test year spending of $18.67 million. For St. Clair (line 18), DTE projects 2021 spending of $36,000, 10-month bridge period spending of $12.08 million, and test year spending of $14.65 million. For Trenton Channel (line 19), DTE projects 2021 spending of $6.91 million, 10-month bridge period spending of $11.6 million, and test year spending of $31.9 million. This PFD discusses these projects together because Mr. Morren treats them collectively in his direct and rebuttal testimony and because the Attorney General, and ABATE adjustments are similar for these lines.

Mr. Coppola recommended excluding the projected 10-month bridge period and test year expenditures for lines 17-19, citing the lack of required managerial approval as shown in Exhibit AG-1.13. His recommended reductions are shown in Exhibit AG-1.14, and for these lines, total $34.1 million for the 10-month bridge period and $65 million for the projected test year.

In rebuttal to Mr. Coppola, Mr. Morren testified that the company has now approved the decommissioning projects for $9.5, $9.5 million, and $9.7 million respectively, citing DTE's subsequent discovery response to Staff that he included in

[227] 5 Tr 655-656.

Exhibit A-40, Schedule EE-1.[228] He reiterated his earlier testimony that the removal includes three steps, decommissioning, decontamination, and demolition.[229] As noted above, Mr. Morren also generally objected to Mr. Coppola's reliance on corporate approval of projects, contending that Mr. Coppola was "applying his own standard of requiring management funding approvals beyond the timeframe of the case."[230]

Ms. York also reviewed the project planning documents included in Exhibit AB-10, and expressed a concern that the amounts identified in those documents for lines 17-19 are significantly less than the amounts included in the rate case. Citing DTE's project documentation in Exhibit AB-10. For River Rouge, she testified: "Specifically, these two documents support capital expenditures of $2.527 million during the bridge period and projected test year. DTE has not provided information discussing the differences in costs between the requested amount included in the bridge period and test year and the supporting project documents."[231] She recommended limiting projected expenditures to the amounts included in the planning documents.

Similarly for the St. Clair decommissioning, Ms. York reviewed the planning documents provided by DTE and included in Exhibit AB-10. She testified that these documents "support capital expenditures of about $36,000 during the bridge period and test year," further noting that DTE had not provided a discussion of the differences between the rate case amounts and the supporting project document.[232]

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[228] 5 Tr 734.
[229] 5 Tr 735.
[230] 5 Tr 733.
[231] 8 Tr 3031.
[232] 8 Tr 3032.

For the Trenton Channel decommissioning, Ms. York reviewed planning documents provided by the company in Exhibit AB-10, and identified a significant difference between the rate case projections and the $50,000 for 2021 she found in those documents, also noting that the project charter estimated a total cost of $5 million for the project. She again noted that DTE had not provided an explanation of the difference, and recommended rejection of the rate case projections on that basis.

Responding to Ms. York, Mr. Morren explained his objection to her recommendation:

> In general, Witness York tries to justify her proposed disallowances utilizing small early capital project data which she appears to not recognize as being related to an early phase of the work that predominately occurred while each plant was still operating. Other than pointing to this irrelevant data, her argument is similar to that of Witness Coppola, which I rebutted [at 5 Tr 734-735], explaining that this post-plant retirement work involves three sequenced primary activities (decommissioning, decontamination, and demolition). Therefore, Witness York's recommendations should be rejected.[233]

In its briefs, DTE relies on Mr. Morren's testimony, noting the three stages of removal, and arguing that the company "needs to and is completing make-safe decommissioning work to protect both personnel and the environment."[234] DTE disputes the Attorney General's concerns with corporate approval as discussed above,[235] citing Schedule EE1 of Exhibit A-40 and arguing that additional funding approvals will be made to complete the work as scheduled.[236] It further argues that the work has already started, "and continuing the work uninterrupted is necessary and well-supported."[237] In

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[233] 5 Tr 749-750.
[234] DTE brief, 22.
[235] See DTE brief, 20-22.
[236] DTE brief, 22.
[237] DTE brief, 22.

its reply brief, DTE further assets: "The projects are approved, and it makes no difference that they were approved sooner than expected."[238]

The Attorney General's brief addresses Mr. Morren's testimony and Exhibit A-40, again citing Exhibit AG-1.69 and arguing:

> The AG asked about this further in discovery. The response to AGDE-11.392 contradicts Mr. Morren's rebuttal testimony that the projects in Exhibit AG-1.14 have received the prerequisite corporate approvals. The date of approval for each project in the discovery response predates the expected approval date provided in response to STDE-3.7c (included in Ex. AG1.13), with the exception of two projects. The two projects are on lines 13 and 21 of Exhibit AG-1.14. These projects were approved by the CEO and, if the Commission sees fit, can be removed from the AG's proposed disallowances for the periods shown. For the other projects, the Company's response to DR STDE-12.5 does not provide sufficient information to establish that the required approval stated in DR STDE-3.7c was obtained. Therefore, the Company has not made a convincing case that those projects should be included in rate base in this rate case and DTE's rebuttal should be disregarded.[239]

Similar to the discussion above, this PFD finds that DTE has failed to support its projected timelines with respect to any details other than a total spending projection. Mr. Morren's assertion that these projects are approved for $9.5 million, $9.5 million, and $9.7 million respectively, is not new information, since the project approvals he relies on were in existence when he responded to the Attorney General as shown in Exhibit AG-1.13. In addition, that these projects provide approval to spend a portion of the company's projections for decommissioning activities says nothing about how the money will be spent or what the overall plan is for managing these expenditures. Mr. Morren testified: "Additional approvals will be gained to complete the work as scheduled," but DTE has failed to explain how or when the work is scheduled.

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[238] DTE reply, 12.
[239] Attorney General brief, 57-58.

For River Rouge, as Ms. York testified, all the project approval documents DTE provided her have small amounts, generally referring to vacuuming fly ash and cleaning ducts in 2020 and 2021—nothing encompasses work for 2022 and beyond.[240] For St. Clair, as Ms. York testified, the total spending is for a relatively small amount, and only for 2019-2021.[241] For Trenton Channel, the 2020 spending of $300,000 covered "Lay up of unit 7 & 8 MTG relays," "Lay up of high side boiler equipment," "removal of fuel supply transformer," "asbestos abatement," and "sealing off of high side/low side inlet canal."[242] For 2020 and 2021, total spending of $227,548 repeats the same project scope.[243] No additional information was provided.

Turning to the approval documents DTE provided in response to the Attorney General's discovery request, Exhibit AG-1.69, DTE produced one new document for River Rouge that had not been provided earlier. This document on page 9 of Exhibit AG-1.69 is clearly intended to show the $9.5 million spending approval that Mr. Morren compared directly to the company's bridge period and test year expense projection total of $29.1 million on page 2 of Exhibit AG-1.69. A review of this document shows that of the $9.5 million stated on that page, $1.57 million is designated for "prior years," with a project start date of 2016, $6 million is designated for 2021, $1.9 million is designated for 2022, and nothing is designated for 2023. With respect to page 2 of Exhibit AG-1.69, the proper comparison should be the 2022 spending on this form of $1.9 million to the $29.1 million DTE projects for the 2022-2023 period. Additionally, while the form was signed in July 2021, it is not clear that the signatory, also the project sponsor,

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[240] See Exhibit AB-10, pages 39, 41, 44, and 46.
[241] See Exhibit AB-10, pages 49, 50, 53, and 54.
[242] See Exhibit AB-10, page 60.
[243] See Exhibit AB-10, page 62.

constitutes the required level of approval,[244] and it is also unclear why this form was not provided to Ms. York. The 2022 spending is in part to develop "an updated project charter" and to develop a request for proposal (RFP), which further calls into question whether DTE has any basis for its total projections for the River Rouge project line.[245]

The form for St. Clair on page 14 of Exhibit AG-1.69 contains a $9.5 million total expenditure for 2022, with no spending reported for prior or future years, and a project description that, similar to the River Rouge form discussed above, includes: "develop project charter and management activities," "demolition RFP and developer RFI/RFP development," "maintain facilities (lawnmowing, snowplowing, security)," "asbestos sampling," and "HAZMAT assessments." With no project charter, no RFP, and no itemized costs, it is again not possible to conclude that DTE has a solid basis for its cost projections.

For Trenton Channel, pages 18-19 appear to contain the approval Mr. Morren referenced; this document shows 2020-2021 spending of $9.7 million and projected 2022 spending of $9.7 million, with no detail. The signatures on the form are dated in January 2022, although the project start date is shown as May 2016. The project description states: "Initial appropriation request for decontamination, decommissioning, and demolition of the Trenton channel power plant. This includes the powerhouse, coal conveyance system, and all associated buildings (admin, clubhouse, etc.)" An interesting note by Mr. Maroun on page 19 of the exhibit, where he has indicated his support for the project, reproduces the projected spending from line 19 of Schedule

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[244] The form states that the approval of the "business unit president" is required; Ms. Harris is listed as Sr. Vice President and the project sponsor. The Attorney General asked in Exhibit AG-1.69 that DTE indicate the highest level of approval received, but DTE did not do that.
[245] Exhibit AG-1.69, page 9.

B5.1, page 2, and states in part: "Project team should be prepared to support prudency of requested project spend while while[sic] they continue to evaluate plant retirement options." Mr. Morren's chart on page 2 of Exhibit AG-1.69 compares the $19.4 million total on this page, half of which is assigned to 2020 and 2021, to the company's 2022-2023 projected expense of $43.3 million.

Because DTE has failed to provide any meaningful analysis or information regarding these projects, treating them collectively as simply a question of how much the spending would be in each period, this PFD finds that the recommended exclusions of the 10-month bridge and test year expense projections should be adopted.

It is worth noting that while Ms. Crozier went out of her way in the context of the depreciation accounting issue discussed above to characterize the net salvage cost analysis—salvage value less removal cost—in Case No. U-16117 as "stale," nothing DTE presented in this case approaches the level of analysis presented in that case, as a review of the Commission's June 16, 2011 order in that case shows. Clearly, DTE knows how to provide a more detailed cost analysis for projects of this type.

3. Steam plant—routine capital expenses (B5.1, page 1, line 2; B5.1, pages 6-7)

a. Attorney General

Mr. Coppola took issue with six projects within the company's routine capital expense category, each on the basis that the company had not established the required internal approvals had been granted. He presented the company's discovery response in Exhibit AG-1.13, and the list of corresponding adjustments in Exhibit AG-1.14 including the routine projects shown on lines 112 and 146 of Schedule B5.1, page 6, and on lines 150, 161, 181, and 197 of Schedule B5.1, page 7. Mr. Morren objected, citing a discovery response provided to Staff and additional information in Schedule EE1 of Exhibit A-40. DTE relies on Mr. Morren's testimony and exhibit.[246]

After reviewing this rebuttal exhibit, the Attorney General agrees that two projects have received approval, including line 112 of Schedule B5.1, page 6 (Belle River Unit 2 LP Turbine Rotor & Blades) and line 161 of Schedule B5.1, page 7 (Greenwood Unit 1 LP Turbine Rotor & Rotor Blades).[247] The remaining routine projects Mr. Morren identified in Exhibit AG-1.14 that are awaiting additional approvals include Renaissance Unit 1 Peaker Turbine Combustion Cans & Hot Gas Path Blades (B5.1, page 6, line 146 and page 7, line 197); and the Monroe Unit 3 Waterwall Tubes (B5.1, page 7, line 181). There is also the 2023 spending associated with the Belle River Unit 2 LP Turbine Rotor & Blades for 2023, Schedule B5.1, page 7, line 150, but this project appears to be part a two-year project that received approval along with the 2022 spending on page 6, line 112, per Exhibit AG-1.69, page 27.

Looking at the Renaissance Unit 1 project, it appears the approval form that DTE relies on is page 29 of Exhibit AG-1.69. Mr. Morren reports this as spending approval for $19.8 million relative to the company's rate case bridge and test year projection of $24.1 million. A review of this page shows that $8.8 million of the capital expenditures reflected in the approval document are assigned to "prior years"; Mr. Morren did not address this. It appears the approved spending for the 10-month bridge and test year for this project that should be included in rates is limited to $11 million. For the Monroe project on page 7, line 181, DTE is projecting expenditures of $1 million in the projected

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[246] DTE brief, 19-20; DTE reply, 11-12.
[247] Attorney General brief, 57-58.

test year; Mr. Morren's exhibit acknowledges that approval is not expected until August. In the absence of additional supporting information showing that this project actually will proceed as scheduled, this PFD recommends that it be excluded from rate base.

b. MNSC

In DTE's first IRP case, Case No. U-20471, the Commission reviewed DTE's analysis of projected retirement dates for Belle River, the Commission concluded that DTE had failed to establish that a 2029-2030 retirement date was reasonable and prudent. The Commission directed DTE to provide a more complete analysis in its next IRP, which DTE now plans to file this fall:

> This information would take into account any changes in environmental laws or formally proposed changes to environmental laws which have occurred in the interim, particularly with respect to effluent limitations guidelines and environmental retrofits. This information shall also include NPVRR analyses, with and without the environmental capital expense and operations and maintenance (O&M) costs discussed in this proceeding and in several rate cases, in order to provide the Commission with additional information on the reasonableness and prudence of planned investments, in several different proposed retirement years including 2024/2025. [248]

The Commission also cautioned the company regarding rate recovery for further investments:

> In the meantime, the Commission will continue to carefully scrutinize near-term capital expense and O&M costs as part of the economic analysis necessary to making these investment and cost recovery decisions in rate cases. The Commission stresses the urgency of this issue given the timeline for environmental expenditures. . . . As the Commission has not found the proposed 2029/2030 retirement date to be reasonable and prudent, there is explicitly no presumption of reasonableness and prudence involving additional expenditures needed to keep the plant running.[249]

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[248] February 20, 2020 order, Case No. U-20471, page 37.
[249] February 20, 2020 order, Case No. U-20471, pages 37-38.

In DTE's last rate case, the Commission further directed DTE to file in its next rate case, i.e. this case, a net-present-value revenue requirement (NPVRR) analysis using alternative retirement dates.[250]

Mr. Burgdorf presented an analysis in this case to address the Commission's order. As part of his analysis, he presented a projection of the MISO local clearing requirement (LCR) for the 2025-2026 planning year, in comparison to the expected resources to meet that requirement, as shown in his Table 5 at 4 Tr 134. With a projected range of a shortfall of 748 MW to an excess of 940 MW, depending on the capacity import limit (CIL) value, he testified:

> The ability to reliably serve load in Zone 7 may be compromised if the Belle River units were not available. As previously discussed, if Zone 7 does not meet the LCR, the MISO auction clearing price for Zone 7 would be set at CONE, and the probability of a loss of load event would exceed the federal reliability standards that govern the resource adequacy planning process.[251]

In his NPVRR analysis, he compared the NPVRR of retiring Belle River in 2023 to the NPVR of retiring it in each of the years 2026, 2028, and 2030. He described four sensitivity calculations for the capacity price in the analysis measured by reference to the Cost of New Entry (CONE) — 0%, 10%, 50%, and 100% — citing the variability in recent capacity price values.[252] He presented Schedules B6.1 through B6.3 to summarize his analysis, also presenting a summary of the results in Table 6 of his testimony at 4 Tr 139, with positive values showing the benefit of retirement in 2023 and negative values showing retirement as the most costly option.

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[250] May 8, 2020 order, Case No. U-20561, pages 80-82.
[251] 4 Tr 135.
[252] 4 Tr 137-138.

Mr. Morren developed the plant capital and O&M cost inputs for this analysis. As Mr. Burgdorf referenced, Mr. Morren also testified to other factors in addition to cost that need to be considered in a retirement decision:

> NPVRR financial analysis results on a single power plant is not the only factor that needs to be assessed when a plant retirement decision is being contemplated. Other factors, such as resource adequacy and grid reliability, need to be understood when determining retirement dates in order to ensure customers retain a reliable and affordable power supply. Resource adequacy considers whether the grid has sufficient resources to meet demand and is described in further detail by Company Witness Burgdorf. Grid reliability evaluates whether the available power can always be delivered when and where it is needed within the region affected by retirement of the plant.[253]

Mr. Morren explained DTE's current plan:

> The most favorable outcome in the NPVRR analysis (Table 6 of Company Witness Burgdorf's testimony) at a capacity price of CONE is retiring Belle River Power Plant'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 has decided that it would be in our customers' best interest for Belle River Power Plant to cease coal-fired operations by the end of 2028.[254]

Mr. Comings reviewed DTE's NPVRR analysis. He listed out the capital cost assumptions for each evaluated retirement year, noting that only the 2030 retirement scenario included ELG compliance costs of $55 million, and also noting that half of the $70 million in additional capital spending needed to keep the plant in operation longer than 2026 DTE plans to incur in 2023. Mr. Comings considered that DTE's analysis supported a 2026 retirement date. He also took issue with DTE's projection of Zone 7 resource adequacy and its focus on a high likelihood of a capacity value at 100% of CONE in 2025/205:

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[253] 5 Tr 712.
[254] 5 Tr 713.

> The Company tries to justify keeping Belle River on-line to address resource adequacy and warns of sky-high capacity prices. But this depiction of resource adequacy in future years is alarmist and flawed. As I describe below: 1) Belle River capacity could be partially or fully replaced; 2) MISO capacity prices are unlikely to be at or near 100 percent of CON in the medium-term; and 3) DTE witness Burgdorf's calculations of resource adequacy are inconsistent with recent changes in the Consumers IRP case.[255]

He further testified that DTE could replace any capacity need with additional resources.[256] He presented a table at 8 Tr 4061 to show that MISO prices over the last 9 years have been volatile but have mostly cleared at prices that are small percentage of CONE:

> I recognize that two of the recent auctions were near or at 100 percent of CONE in Zone 7; but preceding both of those auctions the prices were quite low. There is little reason to believe that prices would stay at 100 percent of CONE for years to come, which is the only assumption that supports DTE's selection of a Belle River retirement at the end of 2028 rather than 2026.[257]

He acknowledged that planning for the retirement of generators, like Belle River requires an assessment of replacement options years ahead of time, which he considered an appropriate subject of the IRP planning process. Mr. Comings further objected to Mr. Burgdorf's use of a 923 MW reduction in Consumers Energy capacity, noting that without this reduction, his analysis would show a surplus of capacity to meet the estimated LCR. He testified that this estimate was inaccurate because it relied on an alternate projection that was not Consumers Energy's preferred course of action in that case, and did not reflect the settlement agreement in that case, Case No. U-21090,

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[255] 8 Tr 4059.
[256] 8 Tr 4060.
[257] 8 Tr 4060.

which has subsequently been approved.[258] Mr. Comings recommended that the Commission disallow the projected costs of five projects, included on lines 151, 154, 155, 158 and 159 on page 7 of Schedule B5.1, that DTE acknowledges are avoidable with a 2026 retirement date.[259] Mr. Comings referred to these by project number (17532, 17531, 17996, 15301, and 15595) as shown in Exhibit MEC-73.

In rebuttal, Mr. Burgdorf addressed Mr. Comings' critique of his Zone 7 capacity analysis. He contended that Mr. Comings' consideration of nine years of capacity prices is not supported by the recent MISO Planning Resource Auction (PRA) prices, which have been set at CONE in two of the last three years, and what he characterized as "the recent transformation of the generation mix across MISO that is underway and expected to continue."[260] He cited an April 14, 2020 MISO presentation that he included in Exhibit A-33, Schedule X1, quoting this passage from the presentation: "Unless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue."[261] He also cited a June 10, 2022 Organization of MISO States (OMS) and MISO survey included in Exhibit A-33, Schedule X3, to show a capacity deficit projected for the North-Central region of MISO for planning year 2023, and expected to widen.[262]

Mr. Burgdorf testified that his direct analysis included all new generation DTE is planning, and disputed that the company could replace Belle River with additional capacity. He also contended that Mr. Comings ignored the potential for other resources

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[258] 8 Tr 4063-4066.
[259] 8 Tr 4067; also on Mr. Comings' list is the Belle River fuel conversion study discussed separately.
[260] 4 Tr 143.
[261] 4 Tr 143.
[262] 4 Tr 143.

to retire in the interim.[263] He updated his Table 5 to reflect what he considered the most recent information, including incorporating values from Mr. Kapinski's testimony for ITC. With a significant increase in the peak demand forecast, an increase in the LCR, along with increased Zone 7 resources, he calculated a range of a shortfall of 1,524 MW to an excess of 545 MW, with an additional calculation of the planning reserve margin requirement (PRMR) net position without Belle River.[264] He explained this last result:

> 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.[265]

Mr. Burgdorf indicated that additional analysis is required and should be included in the company's upcoming IRP filing:

> While my retirement analysis shows that keeping Belle River through 2028 is prudent based on economics alone, a more comprehensive analysis needs to include grid studies performed by ITC analyzing cost of system upgrades for various scenarios. This analysis is being performed as part of the Company's next Integrated Resource Plan.[266]

In his rebuttal testimony, Mr. Morren also objected to Mr. Comings recommendation to exclude avoidable cost under a 2026 retirement scenario. He also stated that the company had not made a retirement decision, and that such a decision is expected to be made through the company's upcoming Integrated Resource Plan filing:

> The Company's upcoming integrated resource plan (IRP) will evaluate the long-term plan for the Belle River Power Plant including evaluating a conversion of Belle River Power Plant to operate on natural gas. The IRP will consider other factors that need to be assessed, such as resource adequacy and grid reliability under various scenarios. On this basis, the

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[263] 4 Tr 145.
[264] 4 Tr 146.
[265] 4 Tr 147.
[266] 4 Tr 149.

> capital expenditures in this rate case that the Company plans to make are required to continue the safe and reliable operation of the plant while providing energy for our customers.[267]

In their briefs, DTE and MNSC continue to dispute the results of the analysis. DTE relies on Mr. Morren's and Mr. Burgdorf's testimony in arguing that an NPVRR analysis alone cannot be relied on in making a retirement decision.[268] DTE emphasizes the OMS-MISO survey and MISO's presentation as reflected in Exhibit A-33, as well as renewable energy project delays also reflected in that exhibit. DTE also cites the Commission's June 23, 2022 order in Case No. U-21099 *et al.*, expressing "concerns regarding the tightening of capacity resources given the implications for resource adequacy and the economic and human impacts of capacity shortfalls."[269] DTE argues:

> 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. 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).[270]

Specifically, regarding the costs at issue, DTE argues:

> The Company disagrees because it has committed to ceasing coalfired 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

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[267] 5 Tr 751.
[268] DTE brief, 31-38.
[269] June 23, 2022 order at 13.
[270] DTE brief, 36.

> 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).[271]

DTE makes similar arguments in its reply brief.[272]

MNSC argues that routine capital expenses at Belle River that are avoidable under a 2026 retirement scenario should be disallowed in this proceeding. Mr. Comings relied on the company to identify the capital and major maintenance O&M costs that would be avoidable if the plant retires at that earlier date. As shown in Exhibit MEC-73, the capital costs include approximately $12.78 million in test year spending. In its reply brief, it addresses DTE's reliance on the Commission's June 23, 2022 order in Case Nos. U-21099 *et al*:

> With respect to the Commission's Order in the capacity demonstration docket, U-21099, DTE focuses on a small excerpt of the Order expressing concern about the tightening of capacity positions in MISO and fails to mention other aspects of the Order that present a positive picture. DTE omits the Commission's recitation of Staff's finding that capacity in Zone 7 will exceed the LCR in PY 2022/2023 by a small amount "and that the Staff is aware of additional capacity resources in the zone that were not included in this year's capacity demonstration" which increase the surplus. The Order also states that Staff found that "LRZ 7 will exceed its projected LCR for the compliance year" of PY 2025/2026 as well as surpluses for the years in between – with the caveat that Staff's projections could change due to "changes in load forecasts, resource availability and performance, MISO policies and practice, and other factors."[273]

MNSC also argues that in that order, the Commission identified measures that could improve the capacity position in Zone 7:

> These measures include lifting a ban on Michigan retail electric customers bidding demand response resources into RTO wholesale markets; considering whether to allow energy storage resources to participate

[271] DTE brief, 38; also see DTE reply, 18-19.
[272] DTE reply, 17-20.
[273] MNSC reply, 2.

> directly in wholesale and retail markets; and taking actions to maximize the benefit of existing transmission connections to PJM and the Ontario Independent Electricity System Operator (IESO).[274]

MNSC further argues:

> As to external resources, DTE's own rebuttal Exhibit A-33, Schedule X1, shows that Zone 7 is projected to have more committed capacity than its PRMR, and additional potential new capacity on top of that, raising the question of whether such external resources would be needed to the extent DTE asserts.[275]

As MNSC argues, DTE's conclusion regarding the economics of retiring Belle River depends on the selection of a narrow subset of alternative values of CONE, which are high historically but not unprecedented recently. Clearly, the economics of retirement and an evaluation of potential alternatives to meet capacity needs will be further evaluated in the IRP. In this meantime, as DTE is continuing to evaluate its retirement options for Belle River, this PFD recommends that the Commission exclude the avoidable costs associated with the 2026 retirement date. The uncertainty surrounding the retirement date, with an upper bound on either retirement or fuel switching seemingly committed by 2028, also causes a concern that DTE will not actually invest in the avoidable costs, should funding be included in rates. While DTE argues that the expenses are "required" while it continues to evaluate its retirement options, it has not established a firm commitment to spend the money as projected. Of course, the Commission will review, and can grant three-year cost approval for, further investments in Belle River in the IRP. Additionally, if DTE does choose to invest in these specific projects, it will have the opportunity to seek recovery in its next rate case.

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[274] MNSC reply, 3.
[275] MNSC reply, 3.

4. Hydraulic plant—non-routine: Ludington Upgrade (B5.1, page 2, line 23)

Mr. Morren identified the cost projections on line 23 of Schedule B5.1 page 2 as related to the efficiency upgrade project being completed at the Ludington Pumped Storage Facility that is being managed by Consumers Energy, Ludington's majority owner.[276] Ms. Champion explained Staff's recommended reductions of $2.66 million for 2021, $187,000 for the 10-month bridge period, and $453,000 for the test year projections for this line item:

> The adjustments in the bridge period are based on the Company's over-projection compared to actuals in 2021 and a mix of 3 months of actuals and 7 months of updated projections for the 10 months ending October 2022. The over-projections for the two periods were 32% and 3% respectively. The total over-projection for the 22-month bridge period was 18%. This was used to adjust the test year in anticipation of a similar over-projection.[277]

In its brief, Staff cites Ms. Champion's testimony and notes DTE did not present rebuttal testimony addressing this adjustment.[278] This PFD thus finds Staff's adjustment should be adopted.

5. Other plant—non-routine (B5.1, page 2, lines 26-32)

i. Blue Water Energy Center (B5.1, page 2, line 27)

Mr. DeCooman explained that Staff reduced the company's projected expenditure for this line item to remove a contingency amount of $8.1 million. DTE did not object to his adjustment and this PFD concludes it is reasonable.

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[276] 5 Tr 656.
[277] 8 Tr 5330.
[278] Staff brief, 10-11.

ii. Blackstart Infrastructure, Site Security, NERC (B5.1, page 2, line 29)

Line 29 of Schedule B5.1 page 2 includes projected bridge period and test year spending of $36.4 million and $11.4 million respectively. Mr. Morren described the projected expenditures:

> Line 29 (Blackstart Infrastructure, Site Security, & NERC Compliance) represents projects that support the North American Electric Reliability Corporation (NERC)black start plan and procedures to improve the reliability of the electric grid. Each region designates certain plants as black start units. A black start unit is one that can start on its own power without support from the grid in the event of a major grid blackout event. General site access security improvements as well as security enhancements for critical equipment are being implemented to mitigate security threats. In addition to physical security, North American Electric Reliability Corporation Critical Infrastructure Protection (NERC-CIP) compliance requires the Company to protect its cyber assets to minimize the risks to the electrical grid. The details for these projects are confidential and are not being disclosed to maintain the security of the electrical grid.[279]

While Mr. Coppola included this project in Exhibit AG-1.14 as a project lacking sufficient corporate approval, he also cited DTE discovery responses in Exhibit AG-1.18:

> The Company has not provided sufficient information to adequately justify undertaking more than $47 million of capital expenditures for Blackstart infrastructure improvements. It is unknown why those improvements are needed, what benefits will accrue to customers, or when the Company will begin to recover through updated FERC Schedule 33 rates either a portion or all of the incremental costs related to those capital expenditures.[280]

Staff also recommended reductions of $8.04 million for the bridge period and $11.52 million for the test year, to reflect amounts approved by DTE management for this project, as well as actual spending. Citing Exhibits S-10.4 and S-10.5, Mr. DeCooman

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[279] 5 Tr 658-659.
[280] 8 Tr 4794.

explained that this project has only received DTE internal approval for $28.4 million in total spending, and:

> Page 1 of Exhibit S-10.4 shows that while the Company requested $4,085,000 in capital expenditures for calendar year 2021, its actual expenditures totaled $385,000, or an overestimation of $3,701,000. Page 2 of Exhibit S-10.4 shows that while the Company requested $32,354,000 in capital expenditures for the 10-months of 2022 included in the bridge period, its mix of actual and updated projected capital expenditures for this 10-month period total $28,385,000, or an overestimation of $3,970,000. This exhibit shows that total capital expenditures in the bridge period are overestimated by $7,671,000, which aligns closely with Staff's adjustment.

Mr. Morren objected that Mr. Coppola essentially double-counted removal of the projected expenditures by inclusion on Exhibit AG-1.14 and making a specific recommendation based on the support for the project.[281] He also testified regarding the importance of the project, referencing his direct testimony at 5 Tr 738-741. He acknowledged that DTE could seek reimbursement from FERC, but not until the project is complete:

> Per FERC Docket No. ER19-2241-000358429 from June 6, 2019, generation owners 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.[282]

In her brief, the Attorney General argues the costs should be excluded from rates in this case.[283] In its brief, DTE relies on Mr. Morren's testimony regarding the Attorney General's proposed adjustment.[284] DTE also relies on Mr. Morren's objection to the Attorney General's disallowance based on lack of proper internal corporate approval, citing Exhibit A-40, Schedule EE1.

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[281] 5 Tr 730.
[282] 5 Tr 740.
[283] Attorney General brief, 62-63.
[284] DTE brief, 22-23.

As Staff notes in its brief, the company did not address Staff's adjustment in rebuttal.[285] DTE also did not address Staff's adjustment in its brief. In its reply brief, DTE argues:

> Staff recommends BlackStart disallowances based solely on the cadence and status of the internal Company approval process, a position that inappropriately elevates administrative matters over the reality that these improvements are required to support grid reliability and are key elements in the FERC-required transmission owner system restoration plan. (Staff Brief, pp. 15-16) There is no material or substantial basis to justify any disallowance of the incremental expenses the Company is incurring for this grid reliability work.[286]

This PFD finds that the Attorney General's recommendation should be adopted. As shown on line 29 of Schedule B5.1, page 2, DTE's total projection for the 22-month bridge period and test year is $47.8 million, with $43.7 million projected for 2022 through the 2023 test year. In Exhibit S-10.5 and Schedule EE1 of Exhibit A-40, DTE reports "complete project approval for $28.4 million." In Exhibit AG-1.69, page 2, however, DTE lists four separate Blackstart projects with 2022 through 2023 test year spending totaling $43.7 million. DTE acknowledges on this page that approval for $16 million is pending, "scheduled for August 2022." DTE then reports approval for $31.6 million, of which it states $27.7 million is included in the 10-month bridge and test year in this case. The additional information on page 2 of Exhibit AG-1.69, however, reports the approval date of November 15, 2021, *i.e.* prior to the date of DTE's response in Exhibit AG-1.13.

Looking at the documentation DTE provided with that discovery response, page 22 of Exhibit AG-1.69 appears to be what DTE is relying on to support approval for a

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[285] Staff brief, 15-16.
[286] DTE reply, 13.

$31.6 million expenditure. This document, however, reports that the approval of the Chief Financial Officer and the Chief Operating Officer are required, and the boxes for those signatures are blank on the form. As discussed above, it is misleading for DTE to suggest that it has obtained any new approvals for this project, since the approval dates predate the discovery response the Attorney General initially relied on, Exhibit AG-1.13. This PFD finds that DTE does not have corporate approval to proceed with the projected 2022 expenditures for this project. The lack of approval, the company's inability to share details of the project, the lack of information regarding the total project cost or project completion date, and the information in Staff Exhibit S-10.4, page 1, showing actual 2021 expenditures of $384,000, well below the company's 2021 rate case projection of $4.1 million, and actual expenditures for the three months of 2022 of only $105,000, cast doubt on the reliability of the company's forecast expenditures. This PFD finds that the projected bridge and test year costs for this project should be excluded from rates.

iii. Hydrogen Fuel System Pilot (B5.1, page 2, line 30)

Mr. Morren testified that the company's hydrogen fuel system pilot includes the construction of an 11 MW electrolyzer with storage capacity and a fuel blending station "to produce and utilize green hydrogen as a fuel source as Blue Water Energy Center to aid in future carbon reduction."[287] He testified that this pilot fits the company's goal of net-zero carbon by 2050.

He explained that DTE envisions hydrogen production via the electrolyzer "using excess electricity from intermittent renewable resources that would otherwise be

[287] 5 Tr 659.

curtailed . . . stored in the form hydrogen that will be available for sustained green power production at a later time when need to support customer demand."[288] As described, the plant would operate during off-peak hours to provide a portion of the on-peak fuel used at BWEC. Mr. Morren identified benefits to customers:

> In addition to eliminating one ton of CO2 for every 17 MMBtu of hydrogen consumed, the pilot facility will allow the Company to gain experience in a technology that is anticipated to play a role in the continued decarbonization of the power sector by storing excess renewable energy that is then used to generate carbon-free electricity during peak demand periods. Experience will be gained in multiple areas, including the design, construction, operation, maintenance, and storage of hydrogen production at an industrial scale. The impacts on the Blue Water Energy Center's equipment maintenance requirements will also be evaluated. This knowledge and operational experience will position the Company to continue to evaluate hydrogen applications, engage with partners such as the US Department of Energy (DOE), and ultimately help integrate large amounts of renewable energy in Michigan and the Midwest region.[289]

Mr. Morren contended that that hydrogen has a promising future in Michigan due to geological formations that could be used to store large quantities of hydrogen, and also due to the Southeastern Michigan industrial sector, which he characterized as "a major logistics and manufacturing hub with international corridors for rail, shipping and highway transportation."[290] He identified five other utilities with hydrogen projects "proposed or under construction," and also cited EPRI and DOE programs "aimed at reducing the cost of hydrogen."[291] To explain why it is important to proceed with this project now, he testified:

> The Company has established carbon reduction goals which are part of the larger movement of the energy industry and society as a whole to reduce carbon emissions. One of the challenges the energy industry will

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[288] 5 Tr 660.
[289] 5 Tr 661-662.
[290] 5 Tr 662.
[291] 5 Tr 663.

> face when shifting to the low carbon paradigm is maintaining electrical grid reliability. Hydrogen is well suited to play an important role in this industry shift as it emits zero carbon and is dispatchable. It is prudent to start incorporating hydrogen now in the planning and execution of the multi-decade shift to a low carbon energy industry. The Company's hydrogen pilot will be the first of its kind in the Midwest and offers an opportunity for the Company to integrate hydrogen fuel into its operations and advance its knowledge of hydrogen technology as it is rapidly evolving. Having experience with hydrogen production and storage now will facilitate the ability to integrate new solutions for hydrogen on the Company's system and potentially partner with US DOE and other entities on new technology applications in the region as part of a comprehensive economywide decarbonization efforts. The hydrogen pilot will accelerate the movement towards a new, carbon-free power generation era.[292]

Mr. Morren further discussed pilot evaluation, how success will be measured, the learnings the company is expected to gain, and stakeholder engagement.[293] He considered the pilot in the public interest:

> Green hydrogen is anticipated to play a major role in decarbonizing the power sector. The integration of hydrogen fuel at Blue Water Energy Center is a first step in learning how hydrogen technology can be applied to create a carbon-free dispatchable resource. The Company will be able to leverage the experience gained from this pilot as it moves forward with delivering reliable, cost-effective, and carbon-free energy to customers. Following the pilot, there is potential to scale up production and storage as hydrogen technology advances and production costs decline.[294]

Mr. Morren testified that total program costs are estimated to $44.6 million, including the $19 million included in the cost projections in this case, with construction to start in 2023 and be completed in 18 months. He also referenced Schedule B5.1.2. of Exhibit A-12 for details.[295] The first page of this schedule includes illustrations of the fuel system and plant layout, while the remaining pages are in table format with boxes corresponding to the pilot program standards.

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[292] 5 Tr 664.
[293] 5 Tr 664-667.
[294] 5 Tr 667.
[295] 5 Tr 659.

Several parties objected to the proposal, with Mr. DeCooman, Mr. Coppola, Ms. York, Mr. Comings, and Mr. Richter all providing testimony.

Mr. DeCooman explained Staff's recommendation to reduce 10-month bridge period expenditures by $839,000 and exclude the entire test year projected expenditure of $17.4 million. Mr. DeCooman cited numerous discovery responses from the company in explaining Staff's conclusion that the pilot generally meets the criteria for pilot program approval. He explained that Staff submitted discovery seeking information regarding the company's statement that it was not seeking external funding, and regarding the cost effectiveness of the pilot, quantification of its benefits, and metrics that could be used. Citing Exhibit S-10.7, he testified that DTE estimated the pilot would reduce BWEC natural gas expense by $70,000-$100,000 annually, and displace 31,777 MMBTU of natural gas and 1,861 tons of carbon dioxide annually.[296] After discussing DTE's participation in other initiatives and programs related to the use of hydrogen in power generation, also reflected in Exhibit S-10.8, he explained Staff's recommendation to reject the pilot as proposed and disallow most of the capital expenditures, primarily because DTE "has not evaluated nor established that the pilot is cost effective or that other benefits it would provide to the Company and ratepayers outweigh the significant costs, totaling nearly 5% of entire construction costs for the BWEC." Further, he stated that potential CO2 reductions the company identified are "a mere 0.05%" of the total expected emissions from the BWEC.[297] As to the potential learnings from the pilot, he considered the company's participation in multiple national initiatives to provide

[296] 8 Tr 5309-5310.
[297] 8 Tr 5312.

opportunities for learnings, with the additional opportunities potentially afforded by the pilot not sufficient "to outweigh the significant cost."[298] He explained that Staff's bridge period disallowance adjusts bridge period spending to the company's updated bridge period spending of $43,000, and Staff excludes test year funding.

Mr. Coppola also cited the standards for pilot approval in explaining his recommendation that the Commission exclude all funding for this proposed pilot from rate base, characterizing it as "too costly an investment without first determining the economic viability of hydrogen plants once deployed at full scale."[299] He considered that DTE fell short of meeting the Commission's requirements for pilots by failing to answer this threshold question, further noting that in its discussion of lessons to be learned from the pilot, DTE does not even mention economic viability as a key finding.[300] Citing the company's rationale for proposing the pilot now rather than waiting, he explained that the company's interest in advancing technology and gaining specific knowledge is only sensible if the hydrogen production is economically viable. He testified that the company did not provide an evaluation of pilots undertaken by other utilities, and characterized the volume of fuel produced by the proposed hydrogen facility and the corresponding carbon reduction as "miniscule relative to BWEC."[301] Mr. Coppola noted that the company is projecting a capacity factor for the plant of 18%, leaving it idle 80% of the time. Looking at the O&M cost to achieve the 31,776 MMBtu, he equated the $470,000 in estimated O&M costs to $14.79/MMBtu, which he characterized as approximately four times the cost of natural gas included in DTE's recent PSCR plan case, Case No.

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[298] 8 Tr 5313.
[299] 8 Tr 4783.
[300] 8 Tr 4783.
[301] 8 Tr 4784.

U-21050.[302] He objected that DTE had not performed a long-term benefit-cost analysis of either the pilot program or the viability of a larger plant. He also noted the Commission's encouragement to the utilities to obtain alternate funding sources for pilots, while DTE indicated it was not pursuing this funding.[303]

Ms. York recommended that the Commission reject rate base funding for this project.[304] She first noted that the project would not be in complete until late 2024, and thus not used and useful within the test year. She also reviewed the project management documents, citing PMP 17315 Rev 3 at page 11 of Exhibit AB-10 and noting that this engineering project was not expected to be completed until 12/30/23. While Ms. York recommended excluding all project costs from the projected rate base calculation, as an alternative she recommended that only the cost of the engineering called for in PMP 17315 Rev 3 be included.

In his testimony for GLREA, Mr. Richter also recommended rejecting the pilot.[305] After reviewing Mr. Morren's testimony and the projected cost of the project, he noted that the pilot is not intended to allow BWEC to run fully on hydrogen, but on a blended fuel with 5% hydrogen and the remainder natural gas. He testified that other utilities have used higher percentages, citing a variety of news articles.[306] Mr. Richter took issue with DTE's concept of hydrogen storage in Michigan geological formations, characterizing it as "vision." Similarly, he took issue with the concept of "using energy that would otherwise be curtailed" as also unrealistic. Mr. Richter addressed the

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[302] 8 Tr 4785.
[303] 8 Tr 4786.
[304] 8 Tr 3023-3025.
[305] 8 Tr 3240-3248.
[306] 8 Tr 3243.

efficiency of the proposed plant, comparing the 2.8 MWh necessary to produce 1 MWh of output to the significantly more efficient Ludington plant that requires only 1.3 MWh of off-peak energy to produce 1 MWh of output.[307] He also disputed the value of the learnings to be gleaned from the pilot, characterizing it as quite expensive. He suggested that DTE could look at other hydrogen storage for combustion turbine projects around the country:

> It is certainly not reasonable that each of the 168 investor-owned and 1,958 publicly owned electric utilities in the U.S. should fund their own hydrogen pilot program, to learn about hydrogen technology. Some knowledge transfer should be required.[308]

He also testified that full ratepayer funding is imprudent because other utilities are getting funding for such projects, providing two examples of federal funding. Finally, Mr. Richter expressed skepticism that this pilot would be useful to a future full-scale hydrogen generation and storage facility, citing "a plethora of research projects and technical demonstrations" in this area to show new technical developments are on the horizon.[309] Listing qualities he believes a reasonable and prudent hydrogen pilot should have, he considered that DTE's project would not have any of these qualities "at least not in any defined timeframe."[310]

Mr. Comings also recommended that the Commission reject the proposed pilot,[311] describing it as "a large and unsubstantiated resource decision that should be disallowed."[312] Noting DTE's plan to burn 5% hydrogen at BWEC, he testified that the

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[307] 8 Tr 3245.
[308] 8 Tr 3245.
[309] 8 Tr 3246.
[310] 8 Tr 3247.
[311] 8 Tr 4079-4084.
[312] 8 Tr 4079.

electrolyzer will provide only 0.06% of annual fuel use at BWEC.[313] He cited Exhibit MEC-68 to show that DTE does not plan to use any hydrogen at BWEC other than what comes from this project. He also cited additional discovery responses from DTE in explaining that DTE had not provided an economic justification for the project, and had not pursued non-utility funding.[314] Mr. Comings also took issue with DTE's claim that its project should be considered "green," disputing its claim to rely on "excess renewables" to operate the electrolyzer:

> When asked if the Company could explain the basis for its belief that there will be excess renewables, the Company falls back on the notion that they do not monitor or know much about excess renewables. DTE then states that to the extent that curtailed renewable energy is unavailable it will purchase "MIREC accounted renewable sources." The MIREC system has been used for Michigan's RPS compliance as a way of tracking renewable energy production. But buying one of these certificates does not mean that the MWh of energy produced would not have been produced regardless, nor that it would spur the need to build or generate additional renewable electricity, especially as Michigan's RPS requirement ended in 2021. If one is purchasing a MIREC from a source that would have produced that MWh anyway, then the marginal energy provided to the grid could come from a non-green source. Therefore, there is a real risk that the hydrogen produced could be carbon intensive.[315]

In rebuttal, Mr. Morren addressed Ms. York's testimony by characterizing the engineering study referenced in PMP 17315 Rev 3 as an "auxiliary" study "designed to provide insight into the future potential ability" to increase the hydrogen blend, and that is the study that will not be completed until 2023. He contended that this auxiliary study should not interfere with the company's ability to complete the hydrogen pilot project construction.[316] He testified that the engineering for the pilot is covered by PMP 17600,

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[313] 8 Tr 4080.
[314] 8 Tr 4081-4082.
[315] 8 Tr 4083.
[316] 5 Tr 741-742.

also included in Exhibit AB-10, which is "sized for supporting up to 5% hydrogen fuel." He addressed the other witnesses recommending against approval of the project by contending that these witnesses give little weight to the following factors:

> • The increasing reliance on intermittent renewable energy on the electric power grid will require a much larger ability to store energy than is currently available.
>
> • Hydrogen production technology seems poised to play a large part in a cleaner energy future.
>
> • Corporate management fully supports this project as indicated by the approval received for this pilot project.
>
> • The utility industry has a large experience base with pumped hydro and battery storage technologies. The Company doesn't have that experience level with hydrogen production and storage.
>
> • A pilot project is the innovative step forward that is needed if the hydrogen economy that is widely spoken of is to become reality.
>
> • Hydrogen production from the pilot could have flexible uses beyond its ability to provide off-peak energy transfer as a fuel for BWEC, including fuel cells and transportation uses.[317]

In its brief, DTE reviews Mr. Morren's testimony, but does not address the contentions of the witnesses in further detail.[318] It objects to any consideration of whether the project will be completed within the test year, also arguing that ABATE's concern is speculative.[319]

MNSC argues that the project is costly, has minimal impacts, is not necessarily able to rely on renewable energy to operate, and DTE has failed to quantify the net cost or benefit to ratepayers.[320] The Attorney General argues that DTE has not established

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[317] 5 Tr 743.
[318] DTE brief, 39-40; DTE reply, 21-22.
[319] DTE reply, 21.
[320] MNSC brief, 136-140.

that the project is in the best interest of its customers, citing Mr. Coppola's testimony, the projected cost of $45 million "assuming no cost overruns," the lack of any external funding, and the expected cost of hydrogen relative to natural gas.[321] Staff also argues that DTE did not establish that the benefits of this pilot, "monetary or otherwise," outweigh the significant expense.[322] Addressing DTE's rebuttal, Staff argues:

> The Company did not address the seemingly significant economic shortfalls of the project, why non-utility funding was not sought, nor why the learnings of other pilots could not mitigate the need for this pilot as proposed.[323]

Relying on Mr. Richter's testimony and Exhibit GLREA-15, GLREA argues that it is "strongly in agreement that new ways to store huge quantities of excess intermittent energy would be beneficial to the grid. However, this specific proposal has numerous weaknesses that warrant its rejection."[324] ABATE urge the Commission to reject the funding, responding specifically to Mr. Morren's testimony regarding the project documents:

> While DTE claimed ABATE's witness confused "PMP 17315, which is a $466K ancillary engineering project designed to provide insight into the future potential ability of BWEC to operate with up to a 100% hydrogen fuel blend, with engineering for the pilot outlined in PMP 17600," it is premature to permit cost recovery of the plant construction project PMP 17600. (Morren 5 Tr 741-42.) Specifically, PMP 17600 provides a project in-service date of December 31, 2024, which is outside the test year used in this case. (Exhibit AB-10 at 5-11.) Further, PMP 17600 includes an assumption that it will take six to eight months to procure permits and DTE stated that long-lead equipment will be procured at the end of 2022, although sufficient updates on the progress of these efforts have not been provided. (Morren 5 Tr 666). This is concerning given the Company's lack of adequate explanation regarding how it is managing supply chain problems and equipment shortages, both of which indicate uncertainty

[321] Attorney General brief, 58-60.
[322] Staff brief, 16-19.
[323] Staff brief, 19.
[324] GLREA brief, 10.

regarding whether this project will be completed in accordance with the planned schedule. As such, DTE's request to collect $19.011 million for engineering, procurement, and installation activities is premature.[325]

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

This PFD notes that certain of the witnesses recommending against approval of the project were charitable in concluding that DTE presented information in compliance with the pilot program standards. DTE did not provide detailed costs: the only cost information in Schedule B5.1.2 was limited to the following information on page 4 of that schedule:

$19.0M of capital costs are forecasted within the rate case filing period (January 1st, 2020 to October 31, 2023)

Total project capital cost: $44.6M

<u>Contract Labor</u>
Engineering: $1.5M
CCGT modifications: $1M
Electrolyzer plant: $16.3M

<u>Material</u>

Electrolyzer: $9.8M
Storage facility: $1.8M
Fuel blending system: $0.7M
Balance of plant: $5.3M

Project management: $0.9M
Indirect costs: $7.3M

[325] ABATE brief, 40-41.

During Operation
Ongoing O&M Costs (Annual): ~$0.12M
PSCR Cost (Annual): $0.35M

The detail regarding the project timeline was limited to

> • The pilot project is expected to begin commercial operations by the end of 2024.
>
> • Operational testing will be commenced immediately. After two years of operations, a complete internal inspection of the BWEC CCGT turbine system will be completed. This inspection will allow a comprehensive evaluation of the effects of hydrogen-fueled operations on the high temperature components in the gas turbine.
>
> • Semiannual reports to be issued on the performance of the system. Results of the hydrogen pilot will be shared with the MPSC Staff and industry groups, as outlined in section 5 below.

In contrast, the primary PAT form DTE relies on for this project identifies at least three steps to the project, engineer, procure, and install.[326] Permitting is another step in the timeline.[327] No timelines are separately stated for these activities. Had the company presented a project timeline organized to include project management steps, completion of engineering, bidding, contracting, permitting, etc., there would not be confusion over the importance of one project number of the two project numbers associated with the project. Also, while DTE objects to Ms. York identifying a change in the schedule for project 17315 as a basis for caution—as shown in Exhibit AB-10, comparing pages 8 and 11—that project shows that DTE is evaluating the possibility of running the BWEC on significantly greater percentages of hydrogen fuel than the 5% manufacturer's rating, which itself is significantly greater than the capacity of the pilot project, as explained by Mr. DeCooman, Mr. Coppola, and Mr. Comings. DTE's own documents link those

[326] See Exhibit AB-10, page 5.
[327] See Exhibit AB-10, page 6, citing 6-8 months for permitting.

projects, as shown by Exhibit AB-10, pages 6, 7, 9, and 10. The latest PAT for project 17315 seeks funding for an "additional (next steps) engineering evaluation for H2 integration and production options at BWEC." That is, DTE is considering alternatives to supply hydrogen for BWEC, and to run BWEC at significantly greater hydrogen amounts than can be supplied by the pilot, and that engineering study will not be completed until the end of 2023. Thus, DTE wrongly dismisses ABATE's concerns with the company's commitment to this project, which is not planned start construction until 2023 and not planned to be in-service in 2024.

More significantly, DTE has failed to show that the pilot is in ratepayers' best interest for the reasons explained by Mr. DeCooman, Mr. Comings, Mr. Richter and Mr. Coppola. Not only has DTE failed to establish that it will be economic to operate this plant, it has correspondingly failed to explain what it will do with the plant if it sits idle after construction. DTE would also expect to recover the removal costs for this project if it is not useful, and DTE has failed to show what those costs are.

iv. Slocum Battery Pilot (B5.1, page 2, line 31)

As Mr. Morren described it, this project is to replace the diesel-fueled Slocum peaker units located in the City of Trenton with a 14 MW / 56 MWhr lithium-ion (Li-ion) battery energy storage system (BESS) that will be charged using off-peak energy and available for dispatch at peak times. He cited Schedule B5.1.3 for details on "the need, goals, design, and expected costs for the Slocum BESS pilot, describes the stakeholder engagement process and details how the project is in the best interest of the public."[328]

[328] 5 Tr 668.

Mr. DeCooman explained Staff's recommended partial reduction of $1.76 million in bridge period spending and full reduction of $26.4 million projected test year spending, beginning with Staff's review of additional information provided by DTE in discovery to determine whether the project met the Commission criteria. He explained that Staff agrees the pilot would provide value to ratepayers in multiple ways, but recommended adjustments because DTE no longer projects it will spend $7.2 million in the bridge period, and because the company "has received only limited budgetary approval" for the test year spending, citing Exhibit S-10.5 to show that approval is for $300,000.[329] He considered it "unreasonable to include the requested test year capital expenditures in customer rates when the project has yet to receive full budgetary approval."[330]

Mr. Coppola also reviewed this project. He recommended that the Commission exclude the bridge and test-year cost projections from rate base.[331] He objected to limited information provided by the company to support the project, testifying that no specific or quantified benchmarks were provided to define a successful pilot, and no analysis that the project can provide capacity at a reasonable cost at the pilot scale or a larger scale. He cited a DTE discovery response in Exhibit AG-17 for the cost figure of $2.4 million per MW for the unit, testifying that this is 25 times the CONE in MISO Zone 7 of $94,000 per MW. He further objected:

> [T]he BESS unit only provides up to 4 hours of energy capacity, meaning that if peak demand continues past 4 hours during hot summer days, the Company need to rely on other generating units or buy power in the MISO market. In other words, the BESS unit is a temporary energy capacity

[329] 8 Tr 5318.
[330] 8 Tr 5318.
[331] 8 Tr 4787-4793.

> replacement and not a longer duration source of energy for extended periods of peak power demand which could be provided by traditional natural gas-fueled peaker generating units.[332]

Similar to his objection to the hydrogen pilot, Mr. Coppola took issue with DTE's explanation for not waiting to learn from other projects testifying that the company's desire to gain experience and establish a process for future grid-scale battery project development and installation would only make sense "if there was a high likelihood that the BESS units would be economically viable once scaled up."[333] He objected that the company did not present any analysis of projects undertaken by other utilities, testifying that "there is not much value in being an early adaptor of new technology if one can learn from others and avoid costly investments."[334] Finally, he cited the concern identified by Mr. DeCooman that the company had not received full authorization for the project, considering it premature to include funding for a project that has not been fully vetted and approved.

In rebuttal, Mr. Morren testified that DTE received management approval for the project in June 2022, citing Exhibit A-40, Schedules EE3 and EE4. He also cited Staff's approval of the project as well as MEIBC/IEI support, citing Mr. DeCooman's testimony at 8 Tr 5319 and Dr. Sherman's testimony at 8 Tr 4399.

In its brief, DTE cites Mr. Morren's rebuttal testimony and Schedules EE3 and EE4 of Exhibit A-40, and argues any concerns with project approval have been

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[332] 8 Tr 4791
[333] 8 Tr 4791.
[334] 8 Tr 4792.

resolved.[335] In response to Mr. Coppola's objections, DTE cites Mr. Morren's rebuttal testimony and also Staff's general expression of support for the project.

The Attorney General argues that the Commission should rely on Mr. Coppola's analysis and conclude that DTE has not justified the project under the Commission's standards for pilot projects, characterizing it as too costly without determining the viability of BESS units deployed at full scale. The Attorney General addressed Mr. Morren's rebuttal testimony, contending that the distinction he draws between storage and generation is unhelpful and does not add to the justification for the project.[336]

Staff argues that the Commission should adopt Mr. DeCooman's adjustment. Citing Exhibit S-10.4, Staff argues its proposed reduction aligns the approved amounts with the mix of actual and updated projected monthly capital expenditures, as well as the approvals DTE now relies on:

> Specifically, while Exhibit A-40, Schedule EE4 includes the full internal budgetary approval, it also includes an updated scoping document with updated costs that align with the amounts identified for budgetary approval. (Morren, Exhibit A-40, Schedule EE4.) This document shows the Company now projects to spend $14,364,949 in 2022, $12,927,383 less contingency in 2023, and $5,749,384 less contingency in 2024. (Morren, Exhibit A-40, Schedule EE4.) This compares to $7,233,000 and $26,430,000 requested in the bridge and test year in the initial filing. (Morren, Exhibit A-12, Schedule B5.2, p. 2, Line 31.) The discrepancy in costs is particularly striking when comparing the new estimate for 2022 capital expenditures with the estimate provided in Exhibit S-10.4, which included 3 months of actuals and estimated $5,431,000 in the 10 months of 2022 included in the bridge period and $10,225,000 over the entire year. (Exhibit S-10.4.) Such a large discrepancy in the current year, compared to an estimate provided less than two months prior, is alarming and raises questions about the cause of these changes in costs. The Company did not specify or provide support for these changes in project costs in 2022 and 2023. Given the fluidity of these costs, Staff's position to

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[335] DTE brief, 40-41.
[336] Attorney General brief, 61-62.

> align the bridge period costs with the Company's forecasted amounts included as Exhibit S-10.4 and disallow capital expenditures in the test year until a future case when the costs have more certainty and can be fully reviewed is the most reasonable position and should be adopted.[337]

DTE addressed this analysis in its reply brief:

> The Company disagrees because Staff generally supports the project and acknowledges that it has full internal budgetary approval. The project involves substantial costs, as most recently and accurately reflected by the approved numbers. Staff's concerns are overstated, and do not provide a sound basis for Staff's proposed 100% disallowance in the projected test year.[338]

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

Indeed, the forms DTE submitted in support of this project are another example of the company's confusing and inconsistent documentation. Page 2 of Schedule EE4 is the first page of the "Appropriation Request" that appears to be approved by DTE's

[337] Staff brief, 19-20.
[338] DTE reply, 24.

Chief Executive Officer and dated June 13, 2022.[339] This form shows a project start date of December 2021, and an in-service date of May 2024. Page 1 of Schedule EE4 is the PAT form, with a signature dated June 13, 2022. This form shows a project start date of July 14, 2021, a construction start date of September 11, 2023, and a project in-service date of April 30, 2024. In contrast, Mr. Morren testified at 5 Tr 670 that the project would be in operation by June 2023, and in his Schedule B5.1.3, also reports that "all capital costs are forecasted within the rate case filing period (January 1, 2020 to October 31, 2023)"[340] and recites that the target commercial operation date is June 2023.[341] Mr. Morren did not acknowledge on the record the discrepancies between his rebuttal exhibit Schedule EE4 and the timeline he provided for the project in his testimony and in Schedule B5.1.3, and DTE does not acknowledge it in its briefs. While Staff may be correct that the approved form represents a change from some earlier projection—in which case DTE should have addressed the change in its rebuttal testimony—this PFD concludes based on a review of the forms in schedule EE4 that even as of November 2021, DTE was not projecting to complete the project until 2024. This PFD reaches that conclusion because the second page of the capital expense Appropriation Request, page 3 of Schedule EE4, shows signoffs by "Corporate Staff" all dated in November 2021, and there is no indication that the first page was altered to reflect a different timeline, once those signoffs had been obtained. In either event, DTE should have acknowledged the approved timeline in its rebuttal testimony. There is also

[339] Although Mr. Norcia's name is typed on the approval line with a date of June 13, 2022, the document also states that it was printed out on June 10, 2022. The record does not reflect whether it is common for Chief Executive approval to be granted without the formality of an actual signature, so this PFD concludes the document has been approved as DTE purports it to have been.
[340] Schedule B5.1.3, page 3.
[341] Schedule B5.1.3, page 4.

a discrepancy between the PAT form and DTE's projected spending in Schedule B5.1 that indicates the projected 2022 spending in the PAT form is overstated; Mr. Morren included only $7.2 million in bridge period spending in Schedule B5.1, with the remaining $26.4 million for this project included in the test year. The PAT form has 2022 spending of $14.4 million, 2023 spending of $12.9 million, and 2024 spending of $5.7 million. As Exhibit S-10.4, page 2 (line 30) showed, based on actual expenditures, DTE's updated projection acknowledged that it would spend $1.76 million less than its 10-month bridge period forecast. That update came from Mr. Morren, however, who appears to have an unrealistic timeline for project completion, since the capital spending document does not grant approval for all spending until 2024. Because DTE has not established that the project will be completed as originally presented, and because the pace of its spending is well behind the pace expected to meet the 2024 in-service date, this PFD finds that the projected costs should be excluded from rate base as Mr. Coppola recommended, with the expectation that DTE will present its actual plans in its next rate case.

B. Nuclear Production (Exhibit A-12, Schedule B5, line 6)

Mr. Davis testified in support of DTE's projected capital expenses for Fermi 2. As shown in Schedule B5.3, page 1, in Exhibit A-12, DTE's projected capital expenses for Fermi 2 are divided into "plant production" and "nuclear fuel," while plant production expenses are further subdivided into a "routine and small projects" category and a "non-routine and large products" category. The only issues raised in this case involve the routine and small projects category. Mr. Davis explained this category:

> Routine and Small Projects are those capital expenditures associated with maintaining the various assets that support the safe operation of the Fermi

> 2 asset and includes work such as pump, motor, valve and reactor control component replacements and can typically be expressed in number of units replaced. Routine and Small Projects are reasonable and prudent because these types of projects are the core of our proactive maintenance regime to maintain nuclear safety.[342]

Mr. Coppola took issue with three project line items within the plant support facilities and equipment subcategory, discussed in the following subsections.[343] In this discussion, the references to Schedule B5.3 are to Schedule B.3 of Exhibit A-12.

1. Plant radio system (Schedule B5.3, line 28)

As shown in Schedule B5.3, page 2, line 28, DTE projects bridge period spending of $3.23 million and test year spending of $3.98 million for this line item. Mr. Coppola recommended excluding the projected costs for this line item, concluding that DTE had failed to provide support for the reasonableness and prudence of the project or the cost projections:

> In his direct testimony, Mr. Jeffrey Davis included no explanation for this large planned expenditure. The information filed by the Company as Part III information provides monthly budget cost projections but no further information on what this project entails, the necessity to undertake the project at this time and why it is necessary, how the projected costs were determined, or why they are reasonable.[344]

In his rebuttal, Mr. Davis asserted that Mr. Coppola's recommendation was based on two misconceptions: first, that the plant radio system is merely ordinary business equipment rather than "plant equipment critical to DTE Electric remaining compliant with its Nuclear Regulatory Commission (NRC) operating license and safe operations of the Fermi 2 Power Plant;" and second, that DTE "did not provide any

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[342] 7 Tr 2541.
[343] 8 Tr 4796-4802.
[344] 8 Tr 4800.

schedules or workpapers that supported project expenditures."[345] Mr. Davis disputed that the word "facilities" could be applied to the radio system, and described the importance of the plant communications system. Mr. Davis contended that he did support the projected expenditures in his direct testimony:

> At line 1 of page JCD-9,[346] I also explain the Small and Routine Projects such as Plant Radio System, Security System Computer and Plant Wireless are reasonable and prudent because they are the core of DTE Electric's proactive maintenance regime to maintain nuclear safety. I also explain at line 14 of page JCD-21[347] that Nuclear Generation capital expenditures must be prioritized consistent with the principles I described in my direct testimony and outlined again here in my rebuttal testimony, as such - the inclusion of Plant Radio, Security System Computer and Plant Wireless project within the Nuclear Generation project portfolio supports the basis of the work, scope of the work and cost of the work are reasonable and prudent.[348]

In the cited portion of his direct testimony at line 14 of page JCD-21, Mr. Davis testified:

> Nuclear Generation manages to total capital expenditures for the period and expects that capital expenditures in total will be incurred as projected. In general, Nuclear Generation maintains a prioritized list of projects such that as project forecasts are over or under expected amounts, Nuclear Generation uses this this prioritized list consistent with the key principles I described earlier to manage the Nuclear Generation portfolio of projects.[349]

He also cited Attachment 9 of the Part III material DTE submitted, describing the information included:

> The Part III information includes detailed information such as amongst other information: when the project was initiated, when the project is expected to complete, the basis for performing the work, the scope of the work, the project's funding status, who is performing the work, how many workers are expected to be used on the project, and the standards to

[345] 7 Tr 2587.
[346] See 7 Tr 2541, quoted above.
[347] See 7 Tr 2553
[348] 7 Tr 2580-2581.
[349] 7 Tr 2553.

> which the work must be performed and project amounts depicted in the previous DTE Electric electric rate case per U-18238[350].

In its brief, DTE relies on Mr. Davis's testimony, including his rebuttal as described above.[351] DTE cites Mr. Davis's testimony in arguing that the Attorney General's recommendation 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 [sic] projects to incur to replace and install systems that are critical to safely operating Fermi 2."[352]

In her brief, the Attorney General relies on Mr. Coppola's testimony as discussed above and further addresses Mr. Davis's rebuttal testimony, citing three additional discovery responses from Mr. Davis, and arguing that Attachment 9 of the Part III material does not support the projected expenditures.[353]

DTE's reply brief further raises an objection to the Attorney General's argument, citing cases referenced in its reply brief at page 2, n2:

> The Company also notes a continuing objection to the AG's briefing approach, including without limitation the general methodology of: (1) starting discussions by incorporating her witness's testimony "in its entirety," and without any specific transcript cites (e.g., Initial Brief, p 64); then disregarding or misconstruing rebuttal; (3) then vaguely pointing to discovery responses as allegedly somehow undermining the rebuttal. The Company attempts to respond for the ALJ's convenience but maintains that there is no requirement to unravel the AG's arguments for her.[354]

The Attorney General further argues in her reply brief:

> Simply because DTE has already spent some of these dollars does not mean that the Company should be guaranteed recovery approval from the

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[350] 7 Tr 2581.
[351] DTE brief, 43-45; also see DTE reply, 24-26.
[352] DTE brief, 44.
[353] Attorney General brief, 65-66.
[354] DTE reply, 25-26.

> Commission, as its brief intimates. DTE failed to provide adequate support for the costs of each of the three projects: how they were determined, why they are reasonable, or sufficient detail on what the projects entail or why they are necessary for customers.[355]

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

Mr. Davis's claim that Mr. Coppola somehow erred in referring to the radio system as "facilities" or "plant equipment" is unpersuasive and of no relevance to the question of whether DTE provided adequate support for its projected expenditures. Note that the Atomic Energy Act is replete with use of the word "facilities." Finally, DTE's objection to the Attorney General citing without further reiterating pages of Mr. Coppola's testimony is actually helpful and not objectionable.

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[355] Attorney General reply, 11.

2. Plant wireless project (Schedule B5.3, line 41)

Mr. Coppola recommended removal of the projected costs for this line item, $2.95 million in the bridge period and $3.19 million in the test year as shown on line 41 of Schedule B5.3, page 3. He testified that DTE had provided no direct testimony in support of this project, and also cited DTE's response to the Attorney General's discovery seeking information about this project:

> In discovery, the Company was asked to explain what was being done with the plant wireless system that would require $6.1 million in capital expenditures and to provide evidence that the projected cost was not excessive. In response, the Company referenced Attachment 9 of the Part III information for additional information and listed five items of precautions that equipment installers need to consider when working in the nuclear facility. Neither of the responses address the request made.[356]

He included the discovery response in Exhibit AG-1.20. Mr. Coppola explained that Attachment 9 of the Part III information "provides monthly budget cost projections but no further information as to what this project entails, the necessity to undertake the project at this time and why it is necessary, how the projected costs were determined, or why they are reasonable."[357]

Mr. Davis provided essentially the same rebuttal regarding Mr. Coppola's recommendation to reject projected expenditures for this line item as discussed above in connection with the plant radio system. Citing the projected cost information in Attachment 9, he further explained why the company does not have a competitive bid for the project:

> [T]he Plant Wireless project was not projected to begin until following Refueling Outage 21, so as expected, there would be no reasonable

[356] 8 Tr 4798.
[357] 8 Tr 4797.

> expectation to have competitive bid information to share until the project has been awarded.[358]

The Attorney General's brief and DTE's brief and reply brief on this topic were in part discussed above. DTE's reply brief also contends that the company appropriately answered the discovery, particularly in view of the time constraints in this case:

> The Company appropriately answered the AG's questions, particularly considering this case's short response deadlines and massive discovery (the Company responded to over 5,600 audit and discovery requests).[359]

After reviewing the arguments of the parties and the record, this PFD concludes that DTE failed to support the projected expenditures. DTE's frustration with the number of discovery questions it must respond to does not justify a slapdash or hasty response. The Attorney General is not required to seek out additional information in support of the company's expense projections. Nonetheless, the Attorney General asked for an explanation "what is being done with the plant wireless that will require $6.1 million from 2022 to the end of the projected test year." The response in pages 5-6 of Exhibit AG-1.20 stated that the projected costs are reasonable and prudent, that the "projected costs, scope and schedule for the plant wireless system were provided in the Attachment 9 of Part III," and provided examples to show that performing work at nuclear power plant involves unique considerations. Since DTE failed to establish that the Attachment 9 Mr. Davis referenced was other than as Mr. Coppola described it, DTE has failed to show what this project entails, the necessity to undertake the project at this time, how the projected costs were determined, or why they are reasonable. Assuming

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[358] 7 Tr 2582.
[359] DTE reply, 25.

DTE does proceed with this project, e.g. by seeking a competitive bid as Mr. Davis indicated, it can seek cost recovery at a later date.

3. Security system computer project (Schedule B5.3, line 50)

Mr. Davis presented testimony in support of the company's projected bridge period and test year expenditures of $12.67 million and $12.07 million, respectively, for the security system computer project:

> The purpose of this major plant security system that includes computer servers, video cameras and other detection devices is to alert plant security of security risks and to maintain positive surveillance of the Fermi 2 Power Plant; loss of the plant's security video system would necessitate compensatory measures to ensure the physical security of the Fermi 2 site. Just like any computer, periodic replacement is necessary to address aging and obsolescence of this key digital asset. DTE Electric expects the replacement of the nearly twenty-year-old security system to complete in 2023.[360]

Mr. Coppola also objected to what he considered a lack of supporting evidence for the projections for this line item. He acknowledged Mr. Davis's testimony, and cited the company's discovery response included in Exhibit AG-1.20:

> In discovery, the Company was asked to explain why replacement of the security video system would require $24.8 million in capital expenditures and to provide evidence that the projected cost was not excessive. In response, the Company referenced Attachment 9.3 of Part III information and listed five items of precautions that equipment installers need to consider when working in the nuclear facility. In this case again, neither of the responses addressed the request made. As discussed earlier, the Part III information is devoid of any explanations or justification about the project other than monthly cost projections. With regard to the challenges of working within a nuclear facility, those challenges in and of themselves do not provide evidence to spend $24.7 million on this project.[361]

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[360] 7 Tr 2542-2543.
[361] 8 Tr 4799.

While Mr. Davis's rebuttal testimony as discussed above in connection with lines 28 and 41 was also applicable to this line item, he further testified that the company's discovery response did demonstrate "the use of competitive bids for the Security System Computer project.[362] DTE's briefs rely on Mr. Davis's testimony while the Attorney General argues that Mr. Coppola's recommendation should be adopted.

This PFD again finds Mr. Coppola's testimony persuasive. There is no evidence DTE has obtained a competitive bid for this project.

C. Distribution System

With 2020 distribution capital expenses of $950 million, DTE is projecting 22-month bridge period capital expenses of $2.3 billion and test year capital expenses of $1.4 billion, approximately 50% and $500 million above 2020 levels. As shown in Schedule B5.4 of Exhibit A-12, DTE has divided its distribution capital expenses into two primary categories, "base capital" and "strategic capital." Base capital includes capital expense to recover from interruptions, add new customers, and relocate infrastructure, while strategic capital expenditures are intended to improve safety, reliability, and operability and invest in grid modernization.

Testimony in support of DTE's projections was primarily provided by Ms. Pfeuffer, with additional testimony provided by Ms. Elliott Andahazy and Ms. Uzenski. Following the Commission's January 31, 2017 rate order in Case No. U-18014, DTE has been preparing and filing five-year distribution plans. The second of the company's five-year plans was filed in Case No. U-20147 on September 30, 2021 and is included as Schedule M1 of Exhibit A-23 in this case. DTE relies on this Distribution Grid Plan

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[362] 8 Tr 2582.

(DGP) as support for its expense projections in this case, particularly its strategic capital investment projections discussed in subsection 2.

Several parties have commented on the distribution plan in this rate case, including MNSC, the CEO, DAAO, and Staff, focusing on grid equity and reliability, but also raising general planning concerns. Several witnesses explained personal and community experiences with power outages. Some of the parties' concerns were focused on recommendations regarding DTE's return on equity or recommendations for performance-based ratemaking. Because some of these concerns involve the company's strategic capital spending, they are discussed in subsection 2 below, while other arguments are discussed in subsequent sections of this PFD.

Also related to distribution expense projections, but not tied to any specific rate adjustment, MNSC argues that the Commission should revise the required contributions in aid of construction (CAIC) or change the allocation of the costs of new connections to match the assumptions underlying the current CAIC policy. This is discussed in section X below. While revenues from these contributions offset the expense projections in this schedule, no party proposed an adjustment to that revenue projection on line 16 of Schedule B5.4, page 1.

In advance of discussing the specific projections at issue, it is helpful to note certain technical issues of a recurring or general nature that relate to or provide background to multiple line items of distribution system capital expense. One such issue involves the classification of costs between "emergent" and "strategic" investments. Citing the Commission's May 8, 2020 order in Case No. U-20561, which called for a detailed description of the costs assigned to the strategic and emergent categories, Staff is concerned that DTE is including some costs in the “emergent” category that are replacements of equipment that is “near failure” but has not failed, as well as including some emergent work in other classifications, such as new load. DTE disputes this. The issue is further addressed in section XII below.

Staff and MNSC also take issue with DTE capitalization policies including inspection and testing costs that they argue should generally be expensed rather than capitalized, and including preliminary project development costs in the technology and automation subcategory that Staff argues should be expensed rather than capitalized. Generally, these disputes and recommendations for the Commission to take action to resolve them for future cases, are addressed in section XII below. MNSC’s concerns are also related to another concern, that DTE is pursuing a policy that promotes replacement over repair at unnecessary costs to ratepayers. DTE has explained that it has adopted revised standards for certain distribution system equipment, including poles, crossarms, cutouts, and insulators, and that these new standards increase replacement costs.[363] MNSC also contends that DTE has an incentive to favor capitalization over expense, and that its distribution system operations are more focused on replacement than repair. These arguments are discussed below and in section XII.

Another issue arising in the disputes over expense projections is the necessity of adjusting historical data for inflation when using this data to project future expenditures. As discussed in connection with emergent replacements in base capital, the

[363] Pfeuffer, 4 Tr 304-305.

Commission has generally adopted an inflation adjustment to the historical data, which DTE refers to as "normalizing." In Case No. U-20561, the Commission explained:

> Adding inflation to the five-year historic actual spend is appropriate for calculating the starting point for normalized expenditures. 4 Tr 245-246. DTE Electric provided evidence that it experienced inflationary pressures during the 2014 through 2018 time period. 4 Tr 246-247, 250-251; 5 Tr 892-952. The Commission also agrees with the ALJ's recommendation to apply the CPI-urban inflation rate (the rate customarily applied by the Commission) to the later years using the Attorney General's more recent calculations. Exhibit AG-1.30. Regarding this inflation dispute, the Commission approves emergent replacement capital spending of $324,699,000 for the bridge period, and $242,250,000 for the test year, which reflects application of DTE Electric's inflationary adjustment to the historical amounts, and the Attorney General's CPI-urban adjustments to the bridge period and test year amounts.[364]

While as discussed below, this PFD generally continues that method, this PFD notes there is some reason to question its validity on the record in this case. As ABATE and the Attorney General argue, DTE has accumulated a multi-year track record of not experiencing inflationary increases in its O&M spending, although DTE cites more recent "choppier" results.[365] Additionally, the record in this case shows significant continuing capital investments in both the company's distribution system and its IT system, which would typically be associated with productivity gains. Ms. Pfeuffer explained the basis of the application of inflation to the company's historical expenditures, citing the need to reflect increased costs for the same amount of work. On this record, however, DTE did not establish inflationary increases in the unit cost of work, and seemed to acknowledge productivity gains indirectly when it responded to testimony provided by Mr. Coppola. In disputing that the labor requirement would

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[364] May 8, 2020 order, page 86.
[365] Crozier, 7 Tr 2390.

double with a doubling of the company's capital investment, DTE essentially acknowledged that it does not need the same inputs to produce the same amount of work.

In the discussion that follows, subsection 1 addresses the disputed issues involving base capital, while subsection 2 addresses the disputed issues involving strategic capital.

1. Base Capital (Exhibit A-12, Schedule B5.4, page 1, lines 1-17)

Base capital expenses were approximately two-thirds of total distributions system capital expenses in 2020, but are projected to be less than half of total distribution capital expenditures in 2023. DTE divides its base capital expense into the following subcategories: emergent replacements; customer connections, relocations & other; and customer advances for construction. DTE provided further detail on the line items included within each of these subcategories in pages 3-7 of Schedule B5.4 of Exhibit A-12, and additional exhibits. Ms. Pfeuffer testified in support of the reasonableness and prudence of expenses in this category and explained how DTE projected bridge and test year costs for each of the line items. The references to B5.4 or to Schedule B5.4 below are to Schedule B5.4 of Exhibit A-12.

a. Emergent replacements (B5.4, page 1, lines 2-7)

DTE projects 10-month bridge expenses of $309.8 million and test year expenses of $371.7 million for emergent replacements. The costs in the emergent replacement category are the capital costs incurred to restore service following storm-related or other outages. Ms. Pfeuffer distinguished costs in this category from other categories in which spending can be planned in advance and subject to peer and leadership review.[366]

Ms. Pfeuffer explained that DTE changed the projection method for this category from a 5-year average to a 3-year average. She cited an increase in the frequency and intensity of catastrophic storms over 2016-2021, as well as an increase in the number of customers affected.[367] She testified that aging infrastructure has also required a significant increase in the equipment used to restore power in storm events. Ms. Pfeuffer further described the 2021 storm events in detail.[368]

Ms. Pfeuffer also testified that non-storm emergent capital costs are increasing. She explained that the non-storm subcategory could include costs related to weather not severe enough to create "storm conditions" of 340 outage events affecting 25,000 or more customers. She also testified that for non-storm replacements, DTE's costs are increasing in part due to the company's "greater emphasis on replacing aged and outdated equipment with new, often higher standard equipment, rather than merely repairing the failed equipment," [369] and she described the higher standards.[370]

Staff and ABATE objected to the change and recommended that the Commission continue to project expenses in this category using a 5-year average. Mr. Becker testified that DTE's three-year average produces a projected test-year expense of $372 million after including projected savings from strategic capital spending.[371] He noted that this amount is $130 million more than the amount approved in Case No. U-20561 for

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[366] 4 Tr 231-232.
[367] 4 Tr 247-248.
[368] 4 Tr 257-262.
[369] 4 Tr 250.
[370] 4 Tr 251-252.
[371] 8 Tr 5400.

emergent replacements. He explained that given the high variability in this category, Staff believes the five-year average is preferable. Mr. Becker provided the details of Staff's calculations with inflation adjustments leading to a $41.26 million reduction in bridge period and a $50.70 million reduction in test year projections.[372] Mr. Becker also explained Staff's concern that DTE characterizes some costs as emergent replacement that should not be classified as emergency work, and vice versa, classifying some emergency work as new load.[373]

Ms. York recommended the continued use of the 5-year average, but without adjusting the historical years by inflation in determining the average.[374] She also cited variable weather, and testified that DTE had not established that the three-year average produces a more accurate forecast. Regarding inflation, she testified that DTE has not shown that these costs were subject to inflationary increases, citing Exhibit AB-10, page 2, to show that DTE admitted that it has been able to offset inflation in recent years.[375] Ms. York proposed a total disallowance of $113.2 million, but did not separate this into bridge period and test year adjustments. Mr. Coppola registered an objection to "normalizing" historical test years by adding inflation to 2020, but did not recommend a revision to the emergent replacement expense projections.[376]

In rebuttal, Ms. Pfeuffer objected to use of a 5-year average, reiterating DTE's concern with storm levels for 2020 and 2021. She disagreed that DTE had not presented evidence that the three-year average would produce a more accurate

[372] 8 Tr 5401-5402.
[373] 8 Tr 5403-5405.
[374] 8 Tr 3035-3037.
[375] 8 Tr 2037.
[376] 8 Tr 4751.

forecast, citing Figures 3 and 4 of her direct testimony at Tr 248 regarding catastrophic storms and related customer outages, and Figure 5 of her direct testimony at Tr 250 regarding non-storm customer interruptions.[377] She also cited information DTE provided in discovery, included in Exhibit A-41, Schedule FF15. This information included an increasing number of storm-related outages for the following aggregated five-year periods: 2007-2011, 2012-2016, and 2017-2021, broken out by medium storms, category 1 catastrophic storms, and category 2 catastrophic storms. It also included data in an attachment to that discovery, showing maximum wind speeds over the time period 2007-2021. Responding to Mr. Becker's concern that ratepayers are at risk from an overprojection, Ms. Pfeuffer testified that there is no risk to ratepayers because DTE "would be able to shift resources to exceed its planned investment in strategic capital," if the emergent replacement expenses do not materialize. Ms. Pfeuffer referenced the company's chronic underspending of projected strategic capital dollars included in rates, citing the Commission's expression of concern in Case No. U-20561:

> As noted by Witness Becker, "The Commission described in its May 8, 2020, order that it is reluctant to cut strategic capital funding and explains how it would like to see a reverse in the historic emergent capital overspend and strategic capital underspend…" page 14 lines 16-18. The Company believes that the three-year average is an accurate forecast for future emergent expenditures, but should they not materialize, the Company would be able to shift resources to exceed its planned investment in its strategic capital activities. This is made possible because the Company is staffing resources at a level to accomplish both the emergent and strategic capital investment. Programs such as Frequent Outage (CEMI), Pole and Pole Top Hardware (PTMM), 4.8kV Hardening, and others that require overhead resources can be quickly ramped up and utilize that capital to provide improved reliability benefits to customers if an emergent under-investment occurs.[378]

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[377] 4 Tr 489.
[378] 4 Tr 491.

In response to Ms. York's testimony, Ms. Pfeuffer testified that it is necessary to adjust for inflation to reflect the time value of money "that acknowledges that to do the same work that was performed in 2018 the Company would need more capital."[379]

Staff's brief recommends the use of a five-year average as recommended by Mr. Becker, noting that DTE's projection in this case is a $130 million increase over the comparable projection in Case No. U-20561, and emphasizing the volatility of weather and the corresponding potential for ratepayers to pay more than necessary.[380] Staff further addressed Ms. Pfeuffer's view that an overprojection is not a concern because the company will shift excess amounts to strategic capital investment, arguing that the Commission does not agree with such shifting. Staff notes that any additional emergent capital the company is required to invest in the test year will be recovered through rate base in future rate cases.

ABATE's brief relies on Ms. York's testimony, objecting to continued use of inflation in the averaging.[381] It argues that when the Commission included inflation in emergent capital spending projections in case No. U-20561, it found that the company experienced inflationary pressuring during the relevant period, citing the Commission's May 8, 2020 order at pages 84-86. ABATE argues that DTE has affirmatively indicated in this case that it has been able to offset inflation in prior years, citing Exhibit AB-10, page 2. ABATE also registers an objection to DTE's proposal to spend overprojections on strategic capital if it is granted the three-year average projection. ABATE

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[379] 4 Tr 492-493.
[380] Staff brief, 22-24.
[381] ABATE brief, 49-51.

characterizes this as a plan to spend extra revenue "in a manner not reviewed by stakeholders or approved by the Commission."[382]

In its brief, DTE relies on Ms. Pfeuffer's testimony. It further blames rate case underprojections of emergent capital for the company's "need to shift resources from strategic capital."[383] It then claims it would be able to shift capital funding not needed for emergent spending to additional strategic capital investments as Ms. Pfeuffer testified. DTE responds to ABATE's inflation objection by arguing that the inflation adjustment is necessary to reflect the time value of money. No additional arguments were raised in reply briefs.

This PFD finds that the 5-year average should continue to be used for this category, with the inflationary or normalization method previously approved by the Commission. Ms. Pfeuffer acknowledged that weather is highly variable from year-to-year,[384] and DTE did not establish that the 3-year average would be more accurate. Instead, it presented five-year averages in only 3 data points, and additional information that is inconclusive.[385] While Ms. Pfeuffer's contention that the three-year average "better represents the conditions the Company has experienced recently" is tautologically true because three years are more recent than five, it says nothing about the predictive power of a 3-year or 5-year average.[386] Nor is it clear that a rate case

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[382] ABATE brief, 50.
[383] DTE brief, 46.
[384] 4 Tr 246.
[385] The Detroit-area wind speed data in Schedule FF15, page 2, has a line fit to the data points, but no statistical analysis is provided showing correlation or variance; the lowest maximum wind speed was in 2010 and the highest was in 2017.
[386] 4 Tr 491.

projection "better allows the Company to plan and prepare for"[387] the required emergent work, since planning and preparing for that work is one of the company's primary responsibilities. As Mr. Becker testified, the consistent use of the 5-year average method should adequately protect DTE's interests, while a significant overprojection by undue reliance on two years of extreme weather will not adequately protect ratepayers. Thus, this PFD concludes Staff's adjustment should be adopted.

This PFD acknowledges ABATE's concern regarding the use of inflation, but as discussed above, in light of Commission orders adopting this method, recommends that the adjustment continue to be used. It is not the company's reduction of inflation for O&M expenses that is most relevant to the determination whether the historical capital costs should be adjusted for inflation; indeed, one concern raised in this case is that DTE has been capitalizing costs that should be expensed, which would reduce its O&M expense for reasons unrelated to inflationary pressures. Nonetheless, DTE has made significant capital investments over recent years, including investments in distribution system technology and tools, as well as IT investments that may have productivity benefits that offset or partially offset inflationary pressures, such that it is not accurate to say that an inflationary adjustment to historical data reflects that it would cost more in today's dollars to do the same work. This can be seen in part from DTE's response to Mr. Coppola's testimony regarding strategic capital, contending that a doubling of spending will not require double the labor. This PFD recommends that the Commission expect DTE to present evidence on that question in its next rate case.

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[387] 4 Tr 492.

It is also necessary to address DTE's efforts to blame rate case underprojections of emergent capital spending for its failure to spend strategic capital as approved in the same rate cases. DTE has an obligation to raise capital for its needs. In addition to projecting rate base additions in advance of expenditures, rates include working capital allowances and a line of short-term debt, which should be sufficient to provide the company with the short-term capital needed between rate cases. Moreover, as Ms. Uzenski's testimony regarding historical results shows, the higher storm rate in 2020 was also associated with above-normal temperatures and higher revenues to DTE on a non-weather-normalized basis.[388] While DTE bears the risk associated with weather that varies from the normal weather assumed in rate cases, it also bears the risk of higher storm activity. One benefit may offset a detriment of such risks, but these risks explain in part why DTE's authorized return on equity is significantly above the risk-free rate.[389] Ms. Pfeuffer's testimony as discussed below regarding strategic capital, contrary to DTE's claims, asserts that the company has devised a management strategy to fulfill its strategic capital plans even with greater than projected storm activity. In a related discussion, Staff responded in its reply brief to DTE's assertion that reliability would suffer if its strategic capital projections are not adopted:

> The Company confuses Staff's recommended disallowances to strategic capital investments for management recommendations. Staff's recommended disallowances only pertain to the reasonableness and prudency of including the proposed costs in rates in this case. The negative impacts detailed by the Company in its brief would only arise if the Company elected to cease or reduce investments in projects with recommended strategic capital investments if it is uncertain such investments would pass reasonableness and prudency reviews for

[388] 7 Tr 2704, Exhibit A-3, Schedule C21.
[389] DTE cites the "regulatory compact" both in its brief at 14 and in its reply brief at 3.

> recovery in future rate cases. However, if the Company invests as it proposes in the areas and such investments are reasonable and prudent, as it claims, then such costs will pass reasonableness and prudency reviews in future rate cases, and it will recover the costs. Given that the Company can recover all reasonable and prudent costs not included in rates at this point in future rate cases, there is little reason to induce system degradation, increase equipment failures, reduce system resilience, and cause a host of other issues mentioned by the Company in its Initial Brief.[390]

b. Relocations (B5.4, page 1, line 10)

The only disputed line item in this category involved the projections for work on the Gordie Howe International Bridge, Schedule B5.4, page 4, line 15. Staff recommended an adjustment to the projections for this category based on updated information.[391] In her rebuttal testimony, Ms. Pfeuffer confirmed that DTE agreed with the adjustment.[392]

c. Electric System Equipment (B5.4, page 1, line 11)

The cost components of the electric system equipment projections on line 11 of page 1 are shown on lines 23-25 of Schedule B5.4, page 4. The only disputed line item is for major equipment on line 24. Ms. Pfeuffer testified that DTE projected this line item for the bridge and test year based on 2020 actuals, increased for inflation.[393]

Mr. Coppola objected to the company's projection. He testified that 2020 expenditures were the highest within the 2017-2021 timeframe, while 2021 actuals were the second lowest within that timeframe. Citing Exhibit AG-1.4, he testified that expenditures within this line item have been volatile, and he recommended using a 5-year average, adjusted for inflation from 2021, but not normalizing each individual year

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[390] Staff reply, 9.
[391] Becker, 8 Tr 5405.
[392] 4 Tr 503.
[393] 4 Tr 370.

within the 5-year average for inflation.[394] The resulting adjustments reduced projected bridge and test year expenditures by $5.8 million and $7.18 million respectively.

In rebuttal, Ms. Pfeuffer objected to the characterization of the expenses for this line item as volatile. She testified that when normalized for inflation, actuals are within 15% of the 4-year average, although she agreed that the 2020 actual expense level was elevated.[395] While she recommended keeping the current method, she testified that if the Commission wants to change the method, it should use a 3-year average, adjusted for inflation, including the normalizing inflation adjustments. She provided revised calculations, with the normalizing adjustment, for both a 3-year and 5-year average in Schedule FF16 of Exhibit A-41.[396]

DTE relies on Ms. Pfeuffer's rebuttal testimony, arguing that the company's reliance on the prior year's spending, adjusted for inflation, should be adopted, with a three-year average as the next alternative.[397] The Attorney General relies on Mr. Coppola's analysis and explains the calculations in Exhibit AG-1.4.[398] In her reply brief, she addressed DTE's recommendation for a three-year average:

> DTE's argument that a three-year historical average would be better than a five-year average, "because it incorporates recent significant increases to resources and funding," ignores the fact that the five-year average incorporates those very same years. The Commission should not allow DTE to use whatever timeframe it finds most convenient for projections in its case.[399]

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[394] 8 Tr 4751-4753.
[395] 4 Tr 499.
[396] 4 Tr 501-502.
[397] DTE brief, 48-49; also see DTE reply, 30.
[398] Attorney General brief, 43-44.
[399] Attorney General brief, 14.

This PFD finds that it would not be reasonable to project this category using the highest reported value; updating the projection with the most recent (2021) value adjusted for inflation is an option, but the 5-year average recommended by Mr. Coppola appears to be the most reasonable approach with the normalization adjustment Ms. Pfeuffer calculated. Using the projected 10-month bridge and test year calculations for the five-year average in Schedule FF16 of Exhibit A-41, this PFD calculates revised reductions of $5.01 million and $6.27 million for the bridge and test year, respectively.[400]

d. NRUC and improvement blankets (B5.4, page 1, line 12)

Ms. Pfeuffer explained that this category includes normal retirement-unit changeouts (NRUC), which are "projects to perform scheduled work for replacement of equipment on the subtransmission and distribution systems, such as the replacement of pole top hardware determined to be at end-of-life (outside of emergent replacements and pole/PTMM)."[401] It also includes "improvement blanket" projects that "are focused on improving operating conditions to reduce the frequency and duration of outage cases such as, installing, replacing or removing fuses and automatic sectionalizing equipment, installing disconnect switches, and removing electrical facilities no longer in use."[402] The component line items in this subcategory are shown on lines 28-32 of Schedule B5.4, page 5. DTE projected costs for these line items using 2020 expenses increased for inflation, with the exception of system improvements in line 28.

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[400] From line 24 of Schedule B5.4, page 4, the 10-month bridge projection is $18.95 million; the adjustment reduces this to $13.94 million from Schedule FF16. From line 24 of Schedule B5.4, page 4, the adjustment reduces the test year projection of $23.4 million to $17.13 million from Schedule FF16.
[401] 4 Tr 381.
[402] 4 Tr 381.

Staff took issue specifically with the projection for system improvements, while the Attorney General took issue with the projection for the NRUC and improvement blanket subcategory as a whole.

i. System improvements (B5.4, page 5, line 28)

Ms. Pfeuffer testified that DTE added an additional annual increase of $2 million to the system improvement cost projections for 2022 and 2023: "System Improvements . . . was forecasted from 2020 actuals adjusted for inflation, and an additional $2 million dollar adjustment was made for 2022 and 2023 to reflect higher costs of projects."[403] Mr. Becker testified that Staff asked the company to support the $2 million annual increase for these years, citing Exhibit S-15.3, page 6. He explained that Staff concluded the added costs were unreasonable, since inflation was already added to the 2020 estimate. Eliminating the $2 million annual addition resulted in a $1.67 million reduction in projected bridge period expenditures and a $2 million reduction in test year expenditures. Mr. Coppola also testified that the company failed to support the projected $2 million increase in his recommendation, discussed below.

In rebuttal, Ms. Pfeuffer stated that the additional $2 million had been requested by the company's regional planning engineers:

> [T]he Company stated in response to discovery question STDE-19.9 that the additional $2.11 million was requested by regional planning engineers, who are often supporting specific customer reliability and power quality concerns, to support doing more small projects locally to improve customer reliability concerns in a quick and efficient manner. Increased funding to the regional planning engineers, typically the front facing employees closest to our customers, ensures that they have the flexibility to quickly resolve smaller in scope reliability equipment issues.[404]

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[403] 4 Tr 375.
[404] 4 Tr 502.

DTE relies on Ms. Pfeuffer's rebuttal in its brief and argues that DTE's discovery response "stated that the additional $2.11 million was required by regional planning engineers."[405] Contrasting Ms. Pfeuffer's direct testimony and Exhibit S-15.3, page 6, Staff argues that DTE did not support the additional $2 million per year in spending, and also cites Mr. Coppola's testimony at 8 Tr 4753-4754. Staff addresses Ms. Pfeuffer's rebuttal testimony by noting the requirement in MCL 460.6a for the utility to place all facts in support of its application in evidence, and arguing that "[h]igher costs of projects are not equivalent to increased reliability concerns."[406]

Staff argues that the company's discovery response in Exhibit S-15.3, page 6 "provided no documentation or support for the additional spend and seems to indicate the additional funding is needed for increasing reliability concerns and customer complaints, not higher costs of projects."[407] Staff characterizes the difference between this explanation and Ms. Pfeuffer's rebuttal as an inconsistency and notes the company's obligation to support its projections, contending it has failed to do so.

In its reply brief, DTE further argues that it is "not requesting the additional $2.11 million merely because costs are higher, as Staff suggests. The Company provided evidence that it needs the additional funding to increase the number of small projects."[408] Then it argues that Staff "does not disagree with the necessity of investments in this category as a whole," and "seems to assume that the addition of inflation to historical actuals should be sufficient." It continues: "This would be a valid argument if the quantity of small projects was to stay the same, year over year.

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[405] DTE brief, 49.
[406] Staff brief, 27.
[407] Staff brief, 26.
[408] DTE reply, 31.

However, Witness Pfeuffer clarified that the number of projects would be higher than in previous years."[409]

ii. Attorney General overall (B5.4, page 5, line 33)

Mr. Coppola considered this subcategory volatile, citing 2017-2021 spending shown in Exhibit AG-1.4. He objected to the company's reliance on 2020 spending plus an inflationary projecting given that 2021 spending was $4.3 million (15.8%) below 2020 spending.[410] Similar to the electric system equipment line item discussed above, Mr. Coppola recommended projecting bridge and test year expenditures for this subcategory using a 5-year average. He calculated a reduction of $7.24 million for the bridge period and $8.99 million for the test year using this average.[411]

In rebuttal, Ms. Pfeuffer disputed that this expense is volatile, contending that it exhibits a "diverging trend" in the last three years:

> There are two distinct 3 periods for these expenditures, 2017-2018 and 2019-2021. The 2019-2021 time period was when the Company began increasing personnel and programs to rebuild and improve the electrical grid. Expenditures averaged $16.8 million in the period from 2017-2018 with actual expenditures for both years clustering close to the average. Expenditures have averaged $23.9 million in the three-year period from 2019-2021, with two out of the three years being within 8% of the three-year average.[412]

Based on the company's increased effort, she recommended a 3-year average as more appropriate for this category, and also testified that the normalizing inflation adjustment should be adopted. She presented revised calculations of the 3-year and 5-year average for this subcategory in Schedule FF16 of Exhibit A-41.

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[409] DTE reply, 31.
[410] 8 Tr 4753-4754.
[411] 8 Tr 4754-4755.
[412] 4 Tr 500.

In its brief, DTE relies on Ms. Pfeuffer's rebuttal, and contends that its discovery response indicating the additional funding was requested by the regional planning engineers does support the expense projection.[413] In her brief, the Attorney General relies on Mr. Coppola's testimony and Exhibit AG-1.4 to support the recommended five-year average.[414] The Attorney General opposes Ms. Pfeuffer's alternative three-year average, and her recommended inflation adjustment, characterizing the latter as not a Commission approved procedure.[415]

iii. Recommendation

This PFD finds that the Attorney General is correct that DTE's projection method for this category is flawed, given the variability of expenditures in this category from year to year. Because the Attorney General's recommendation addresses the entire category, this PFD recommends that her adjustments be adopted, with the addition of the normalizing adjustments for the five-year average presented by Ms. Pfeuffer. The resulting reductions to the 10-month bridge period and test year projections are $6.23 million and $7.66 million, respectively.[416] This PFD also concludes that Staff's analysis is correct in that DTE failed to establish the reasonableness and prudence of the additional $2 million in annual spending for line 28. The company's citation to the request by engineers is not sufficient to justify the expense, nor does it match the company's initial claim that the increase was due to the higher cost of projects. Somehow, in its reply brief, DTE appears to have lost sight of the fact that it was its own

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[413] DTE brief, 48-49; also see DTE reply, 30.
[414] Attorney General brief, 44-47.
[415] Attorney General brief, 46.
[416] From line 33 of Schedule B5.4, page 5, the 10-month bridge projection is $25.41 million; the adjustment reduces this to $19.18 million from Schedule FF16. From line 33 of Schedule B5.4, page 5, the adjustment reduces the test year projection of $31.23 million to $23.58 million from Schedule FF16.

initial assertion that the reason for the additional $2 million in funding was due to "higher costs of projects."[417]

e. General plant, tools, and equipment (B5.4, page 1, line 13)

DTE projected this line item based on 2020 expenditures, increased by the company's inflation projection for the bridge and test year period. As with the electric system equipment line item discussed above, Mr. Coppola testified that this subcategory of expenditures has been volatile, with 2021 actuals below the 2020 actuals. He recommended the use of 5-year average to project this category, with inflation from 2021, but without the normalizing adjustments to the historical data prior to averaging. The resulting adjustments reduce the projected bridge and test year expenses by $2.18 million and $2.7 million, respectively.

In her rebuttal, Ms. Pfeuffer again objected to the use of an average for this category, although she considered it more variable than the electric system equipment or NRUC line items discussed above. She also objected to the lack of normalizing adjustment for the historical years, and presented revised 3-year and 5-year averages in Schedule FF16 of Exhibit A-41.

DTE addressed this line item collectively with the line items for NRUC and improvement blankets and electric system equipment discussed above, relying on Ms. Pfeuffer's rebuttal testimony.[418] The Attorney General similarly relies on Mr. Coppola's testimony.[419] Consistent with the discussion above, this PFD finds that a project based on 2020 expenditures adjusted for inflation is not appropriate for this category given the

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[417] Pfeuffer, 4 Tr 375.
[418] DTE brief, 48-49; also see DTE reply, 30.
[419] Attorney General brief, 47-48.

variation from year to year. This PFD concludes that a five-year average is the most reasonable of the alternative projections, normalized for inflation as shown in Schedule FF16 of Exhibit A-41. The resulting adjustments to the bridge and test year expense projections are \$1.72 million and \$0.67 million, respectively.[420]

2. Strategic Capital (B5.4, page 1, lines 19-21)

DTE's 2020 strategic capital expenditures were \$307.6 million. DTE is projecting test year expenditures of \$798 million, an increase in annual spending of approximately \$500 million or 160%. Total capital spending for the 22-month bridge period and test year total approximately \$1.75 billion.

Strategic capital expenditures are not reactive to failures and are intended to improve safety, reliability, and operability and invest in grid modernization. The company's strategic investment plans are the primary subject of its five-year Distribution Grid Plan (or DGP) filed in September 2021 in Case No. U-20147. This DGP is included in the record as Schedule M1 of Exhibit A-23, sponsored by Ms. Pfeuffer. While there are several metrics used to measure the performance of the company's distribution system as discussed in that report, Ms. Pfeuffer considers the System Average Duration Interruption Index (SAIDI), both "all weather" and "excluding major event days," to be the most useful.

Ms. Pfeuffer acknowledged underspending of approximately \$54.3 million in the strategic capital category in 2020 relative to the company's prior rate case projection, also noting the significant increase in emergent and other base capital spending that

[420] From line 13 of Schedule B5.4, page 1, the 10-month bridge projection is \$7.04 million; the adjustment reduces this to \$5.72 million from Schedule FF16. From line 13 of Schedule B5.4, page 1, the adjustment reduces the test year projection of \$8.7 million to \$7.03 million from Schedule FF16.

year relative to the rate case projection, as well as the pandemic.[421] As shown on page 1 of Schedule B5.4, strategic capital spending is divided into three main subcategories: infrastructure resilience and hardening, infrastructure redesign and modernization, and technology and automation. Component line items and further detail regarding these expenditures are shown in subsequent pages of Exhibit A-12 and in Exhibit A-23.

In her direct testimony, Ms. Pfeuffer provided little information regarding how costs in this category are forecast. Asked explicitly in her direct testimony how the company forecast capital expenditures in this case, for strategic capital, she answered: "Based on the grid modernization no-regrets investments identified in the DGP submitted September 30, 2021."[422] Ms. Pfeuffer also cited Schedules M4 through M6 of Exhibit A-23, testifying that DTE provided additional detail about its needed capital in Exhibit A-23, stating: "Exhibit A-23 provides much greater detail for the projects and programs in Exhibit A-12, Schedule B5.4, which represents 100% of the Company total forecasted capital."[423] She further described the documents in these schedules:

> Each document, which can be one to several pages, includes the following:
>
> • Program: As described in Exhibit A-12, Schedule B5.4, pages 4 to 11, column (a).
> • Purpose and Necessity: A description of the driving forces for the work.
> • Category: The pillar of Strategic Capital spending from the DGP.
> • Line Number: A reference to the page and line numbers supported.
> • Scope: The scope of work.
> • Customer benefits / Effect on cost of operation and reliability: How the Company's customers benefit from the program and a

[421] 4 Tr 242-257.
[422] 4 Tr 371.
[423] 4 Tr 386.

> description of the how the project or program is expected to impact operations and reliability.
> • Impact Dimensions: The dimensions from the GPM described in Question 45 that the project or program will impact.
> • Current Projects: Current projects underway that support the described program.
> • Cost: The expected cost of the program over a specific timeframe.
> • Test Year: The expected cost of the program for the projected test year including a breakdown of the costs by labor, material and other costs.[424]

Looking at the strategic capital spending projections as a whole, the company is projecting a 96% increase in 2022 spending over 2021 levels and an additional 17% increase in 2023. Mr. Coppola characterized this as a "dramatic escalation."[425]

a. General

As noted above, several parties raised concerns with DTE's strategic capital spending plan. Some of the general concerns are reviewed before specific line-item disputes.

i. Chronic underspending

Several parties focused on the company's chronic underspending in this category, with Staff and the Attorney General recommending reductions in the company's expenditures on this basis. In Case No. U-20561, the Commission considered 2019 underspending on strategic capital investments, explaining:

> The Commission also disagrees with DTE Electric's view that DO capital expenditures should be treated as a single entity, putting, for all practical purposes, strategic capital and emergent replacements in the same bucket. This would erase the intended "strategy" of strategic capital – to improve future reliability and resiliency, and reduce risk. The Commission is reluctant to cut strategic capital funding which addresses such essential tasks. However, the evidence shows that strategic capital was underspent

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[424] 4 Tr 387.
[425] 8 Tr 4757.

> in 2019, while emergent replacements capital was overspent in 2019. The Commission would like to see these results reversed—strategic capital can and should be used to strengthen infrastructure resilience, hardening, technology, and automation in ways that will significantly reduce the need to throw out the company's prior test year projection for emergent replacements in every rate case due to unexpected emergency expenditures. As discussed more fully below, the Commission continues to have very real concerns over the long-standing poor reliability performance of the company's distribution system, and re-emphasizes its expectation that DTE Electric will use the dollars approved in rates tied to improving reliability for their intended purpose (i.e., strategic capital investments category), and not shift them to other categories such as emergent replacement and other reactive spending.[426]

Ms. Pfeuffer responded in two principal ways. She testified that 2020 and 2021 are not good measures of the company's future ability to implement its strategic planning investments, given both the pandemic and the high level of storm activity.[427] She also testified that DTE has implemented significant changes to better ensure that it can achieve planned investments in this category.[428]

It should also be noted that DTE is including some offsetting savings in its emergent capital spending as a result of its strategic capital investments. This is shown on line 6 of Schedule B5.4, page 1.

ii. Proactive replacement

Mr. Ozar also discussed general principles he considers applicable to this category, while focusing his testimony primarily on the 4.8 kV hardening program and PTMM.[429] In particular, he discussed the company's concept of "proactive" replacement:

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[426] May 8, 2020 order, Case No. U-20561, page 91.
[427] 4 Tr 409.
[428] 4 Tr 410-412.
[429] 8 Tr 3961-3967.

> In my opinion, asset replacements should be based on the two core principles "replacement upon failure" (including incipient failure) and "replacement upon imminent failure" with respect to preemptive replacement.
>
> With these core principles driving distribution asset replacements, it should be expected that the preponderance of asset replacements would be those having experienced actual failure, whether or not related to storm damages. To a much lesser degree, pre-emptive replacements may be needed of assets that have not yet failed, but giving signs of immediate occurrence of failure, e.g., imminent failure.[430]

In contrast, he testified, "the Company's replacement policy is more expansive, going well beyond preempting imminent failure."[431] Mr. Ozar considered the level of preemptive replacement in the company's capital expense projections to be "staggering,"[432] and expressed concerns generally, and with regard to two specific programs discussed in more detail below.

Ms. Pfeuffer acknowledged the company's emphasis on replacement rather than repair, but testified that repair remains an option under the company's policy, citing her direct testimony at 4 Tr 250-251:

> I explained that "[a]nother driver of the increase in non-storm emergent capital expenditures was a greater emphasis on replacing aged and outdated equipment with new, often higher standard equipment, rather than merely repairing the failed equipment." The Company has placed an emphasis on replacing instead of repairing outdated equipment, but it does not in fact require replacements. Pages SGP-27 and SGP-28 go on to show why the Company is doing more replacements than repairs. Placing a greater emphasis on replacement of outdated equipment rather than repairing it does not equate to a requirement to do so in all instances. The decision to repair vs replace is often made in the field by lineworkers, depending upon factors that include the amount and type of damage, and field conditions that affect the difficulty of a repair or a replacement during storm or emergent conditions. A simple inexpensive fix to repair the

[430] 8 Tr 3961.
[431] 8 Tr 3961-3962.
[432] 8 Tr 3963.

closure on an electrical cabinet will be made rather than replace with a newer cabinet, for instance.[433]

iii. Expense projection disputes

Spending in the strategic capital category was also the focus of several parties' general concerns regarding the company's distribution system planning. The Attorney General, Staff, and ABATE each recommend broad-based reductions in the company's strategic capital spending. The Attorney General looks at the entire line item for this category; ABATE's recommendations focus on projects Ms. York concluded DTE had not established would be used and useful within the test year; Staff looked at the three subcategories of strategic capital separately, with Mr. Becker explaining Staff's recommended adjustments to the "infrastructure resilience and hardening" and "infrastructure redesign and modernization" subcategories, Dr. Wang focused on the third subcategory, "technology and automation," and Mr. Evans specifically addressed two line items, the strategic undergrounding pilot and the conservation voltage reduction (CVR) project.

As discussed below, while this PFD concludes that the broad-brush recommendations are not unreasonable, especially in view of the company's chronic underspending in this category, this PFD makes recommendations regarding the individual line item disputes as discussed below, with a concluding recommendation following the discussion.

[433] 4 Tr 498.

b. Attorney General overall

Mr. Coppola recommended a 20% reduction to the company's strategic capital expense projections for 2022 and 2023. 8 Tr 4757-4761. In Exhibit AG-1.5, DTE was asked to provide historical data comparable to Schedule B5.4, page 1, for each year 2016-2021. DTE indicated that it could only provide the information for 2017-2021, with that historical spending along with projected spending included as page 2 of Exhibit AG-1.5. Mr. Coppola testified to an approximately 20% annual growth rate in strategic capital spending over that 2017-2021 period:

> The 20% average annual increase in capital spending for this set of programs appears to be a more manageable and achievable level of activity than the doubling of the program spending proposed by the Company. As stated earlier, the Company's track record of not achieving the forecasted level in spending in two prior years, the challenges posed by the supply chain to obtain needed materials, and the ability to hire and train new employees or contractors over than next year makes the Company's projected capital spending speculative and unlikely to be achieved.[434]

Applying a 20% increase to the 2021 actual spending level of $359 million, and additionally incorporating an inflationary increase, Mr. Coppola calculated projected 10-month bridge period spending of $371 million and test year spending of $546 million. These projections equate to reductions in the company's projections of $209 million for the 10-month bridge period and $252 million for the test year.[435] Mr. Coppola also identified four specific cost projections in the company's more-detailed spending plans that he recommended be removed or significantly reduced, clarifying that these

[434] 8 Tr 4760.
[435] 8 Tr 4760-4761.

reductions would be subsumed within his overall 20% spending growth.[436] Those specific cost projections are discussed in more detail below.[437]

Ms. Pfeuffer objected to this recommendation in rebuttal. She reiterated her testimony that the company has taken steps to mitigate supply chain and labor issues, also objecting that Mr. Coppola did not establish that the company's cost projections include proportional increases in labor requirements.[438] She specifically objected to the use of average percentage increases.[439] Citing the DGP, she testified that the needs of the grid change over time. She also reiterated her view that 2020 and 2021 were significantly impacted by circumstances beyond the company's control. Additionally, she objected to Mr. Coppola's use of the period 2017-2021, testifying that he "arbitrarily begins his analysis with the calendar year 2017,"[440] and she objected to his focus on the strategic capital subcategory, testifying that "by only focusing on strategic capital AG Witness Coppola is discounting the Company's total ability to execute capital investments."[441] Ms. Pfeuffer presented revised calculations in Schedule FF19 of Exhibit A-41 to show that for the years 2016-2019, the company's average annual growth rate for total distribution system capital was 23%, and for the years 2016-2020, "it was still at 16% when including the pandemic impacted 2020 year."[442] She also calculated compound growth rates over these periods for strategic capital, testifying "the Company believes that the most accurate view would be the 3 year 2016-2019 compound annual

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[436] 8 Tr 4761-4762.
[437] The four projects are the strategic undergrounding pilots, the ADMS-NMS and ADMS-DMS/OMS projections, and the Systems Operating Center (SOC) cost overruns. Coppola, 8 Tr 4762.
[438] 4 Tr 398, 413-415, Schedule FF2 of Exhibit A-41.
[439] 4 Tr 416-421.
[440] 4 Tr 417.
[441] 4 Tr 418.
[442] 4 Tr 418

growth rate of 33%, which is only slightly less than the Company's proposed 39%." The 39% growth rate shown in Schedule FF19 reflects the period 2020 through 2023.

DTE's brief relies substantially on Ms. Pfeuffer's rebuttal testimony and Exhibit A-41, asserting the company's projections are based on grid needs, characterizing the Attorney General's analysis as arbitrary and not reflective of unique circumstances in 2020 and 2021, and highlighting the company's claim that it has improved its total ability to execute capital investments.[443] It contends that the proposed reductions would have negative impacts on safety, reliability, and emergent costs.[444] The Attorney General argues that Mr. Coppola's recommended adjustments are more appropriate for the bridge and projected test year. The Attorney General dismisses as not credible the company's claim that labor requirements will not double with the capital expenditures, and discusses the individual projects Mr. Coppola cited as examples of programs that could be removed or significantly reduced.[445]

As Mr. Coppola testified, the company's projection for this category reflects a 96% increase in 2022 spending compared to the estimated 2021 value in the company's filing for strategic capital, and 94% if actual 2021 spending is included. First, it is important to note that these compound growth rates under discussion are essential exponential rates of growth; DTE is arguing that it needs to increase its rate base to reflect an approximately 36% annual growth rate over the period 2016 to 2023 in distribution system capital spending. As Mr. Coppola testified, these are substantial numbers with a significant impact on rates.

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[443] DTE brief, 55-58; also see DTE reply, 33.
[444] DTE brief, 58, citing Pfeuffer at 4 Tr 287.
[445] Attorney General brief, 48-54.

It is also somewhat disingenuous of DTE to accuse Mr. Coppola of arbitrarily choosing 2017 as the starting point for his calculation, since DTE stated in discovery that comparable numbers were not available for 2016 and did not provide them for any of the lines in Schedule B5.4, page 1, including total strategic capital spending.[446] Because the company did not provide a chance for the 2016 data to be evaluated for comparability, this PFD finds that the Attorney General did not arbitrarily exclude 2016 from the analysis.

DTE has also not established that 2020 or 2021 actual spending should be excluded. Looking at the 5-year period 2016 to 2021, the compound annual growth rate using 2021 actual spending is 22%. Looking at the entirety of the 2016-2023 period for which actual or projected values are available, the company's filing reflects an overall compound annual growth rate of 30% per year over a 7-year time period, or an increase from what Ms. Pfeuffer's Schedule FF19 shows as a 2016 spending level of $133 million to a projected 2023 spending level of $881 million. The company achieves the exponential growth rate of 30% per year over the period 2016-2023 under its projections, in contrast to the 23% average annual increase over the period 2016-2020, by essentially doubling the amount of its expenditures from 2021 to 2022. Considering what is specifically before the Commission in this case, since 2021 actual spending is known, DTE's proposed 2023 spending of $818 million reflects an over-50% compound annual increase from 2021 to 2023, with the bulk of that increase projected to occur from 2021 to 2022. This requires an increase of approximately $350 million in spending from 2021 to 2022. Yet, as Mr. Becker noted, the company has not yet actually spent as

[446] See Exhibit AG-1.5.

much as $360 million in a single year, and it has not shown that it can sustain that level, let alone nearly double it.

Viewed linearly, this $350 million increase in spending in a single year dwarfs the amount of spending increase in any year over the period 2016-2021, in which the largest spending increase in any year was the approximately $100 million increase between 2017 and 2018.[447] While the company's efforts to better manage its expenditures in this category are commendable, the Attorney General and Staff reasonably question the company's ability to accomplish an increase of this magnitude given historical spending levels and historical failures to meet strategic capital spending targets.[448]

It is true that the pandemic hampered DTE's ability to implement its plan in 2020, with additional supply shortage and labor issues following, but DTE also cited a hurricane restoration efforts in Puerto Rico, as well as delays in permitting, new substation costs, and changes in customer requests as the basis for its $126 million underspending in 2019. While DTE explains it has revised its management operations to be able to meet these targets, it appears reasonable for the Commission to allow DTE to demonstrate the benefits of its improvements on a smaller scale, before authorizing more expansive funding.

For these reasons, the Attorney General's recommendation to limit overall projected spending increases in this category to 20% is a reasonable recommendation. It does, however, lack the guidance associated with a more detailed review of the

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[447] See Exhibit AG-1.5, page 2, line 22.
[448] Staff's adjustments are made by subcategory as noted above, and as discussed in subsections d through f below.

specific line items or subsets of line items. Staff, the Attorney General, ABATE and MNSC make recommendations regarding subcategories or smaller components of the company's projections. Bearing in mind Mr. Coppola's broader recommendation, the specific recommendations made by the parties regarding various line items making up the company's total projections for this category are discussed in the following subsections.

c. ABATE overall

Ms. York testified generally regarding strategic capital expense projections that several projects are not expected to be in service until after the end of the test year.[449] She cited pages 8-11 of Schedule B5.4, and recommended a total reduction in bridge and test year expense projections for this category of $753 million, but did not provide additional detail regarding the specific line items that comprise this total.

In rebuttal, Ms. Pfeuffer cited Ms. Crozier's testimony that utilities may earn a return on construction work in progress, and also testified that just because a project is not completed during a rate case test year does not mean it is not providing benefits for customers.[450] As examples, she indicated that circuits may be converted over a period of years but the substation will not be decommissioned until all circuits are addressed.

DTE's brief relies on Ms. Pfeuffer's and Ms. Crozier's rebuttal testimony.[451] It contends that ABATE's focus on the used and useful standard is "against Commission precedent," and cites *ABATE v Public Service Comm*, 208 Mich App 248, 258-259 (1994) to show that the Court of Appeals has held the Commission is not required to

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[449] 8 Tr 3057-3059.
[450] 4 Tr 415-416.
[451] DTE brief, 58-60.

apply the used and useful test, and it cites *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6 (1999) to show that the Commission is not bound by any particular formula or use any specific method in setting rates.[452] It further argues that ABATE's recommendation should be rejected "because it is based on the inaccurate proposition that 'DTE has not provided detailed information supporting the amounts of capital expenditure expected to be incurred during the bridge period and projected test year.'"[453] DTE cites the pages of testimony, pages of exhibits, and number of discovery and audit requests it provided, to show that it provided details regarding each of these programs included in-service dates. It reiterates these arguments in its reply brief.[454]

ABATE argues for the adjustment recommended by Ms. York.[455] ABATE responded to Ms. Pfeuffer's rebuttal in part as follows, referring to the magnitude of projected spending increases in this case and the company's history of underspending:

> The Company's amorphous claim that "just because a project is not completed within the rate case period does not mean it is not providing benefits to the customers" is not a reasonable or prudent basis upon which cost recovery for these specific projects should be granted at this time, particularly considering the projected test year concerns and history noted above. Stated differently, these general assertions do not demonstrate recovery commensurate with customer benefit and cannot supported advanced cost recovery for specific projects.[456]

While certain line items discussed on the record on this case and below in this PFD do show that the Commission should be cautious in including funding in rate base for projects that will not be completed within the historical test year, the lack of detail

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[452] DTE brief, 58 at n34.
[453] DTE brief, 59-60, also citing York, 8 Tr 3038.
[454] DTE reply, 35-36.
[455] ABATE brief, 51-52.
[456] ABATE brief at 51-52.

provided by ABATE regarding the components of Ms. York's adjustment makes it difficult to recommend. Instead, this PFD's recommendations for strategic capital spending are explained in subsections d, e, and f below.

d. Infrastructure resilience and hardening (B5.4, page 1, line 19)

Ms. Pfeuffer described the expenditures in this subcategory as projects and programs that are focused on replacing aging infrastructure, hardening the system, and addressing areas with known poor reliability.[457] The company is proposing to approximately double spending in this category in the projected test year, relative to 2020 levels. Additional detail is presented in Schedule B5.4, page 8. As discussed below, Staff recommends an overall adjustment to this category, ABATE broadly recommends the exclusion of projected spending for projects that will not be complete by the end of the test year, while MNSC focuses specifically on two programs.

i. Staff overall

Similar to Mr. Coppola's approach but focused specifically on the infrastructure resilience and hardening subcategory of strategic capital expense projections, Mr. Becker recommended that the Commission reduce the company's projected expenditures in this category by 15%, to reflect the average level of underspending as shown in Ms. Pfeuffer's Table 6 at 4 Tr 243 and Exhibit S-15.3, page 3.[458] He cited the Commission's concerns with the company's chronic level of underspending on strategic capital investment in Case No. U-20561, testifying that DTE "failed to demonstrate its ability to spend at projected levels."[459] Staff's recommended adjustment reduces 10-

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[457] 4 Tr 277.
[458] 8 Tr 5409-5411.
[459] 8 Tr 5410.

month bridge period spending by approximately $40 million and projected test year spending by approximately $52 million. As discussed in more detail below, Mr. Becker also raised a concern with the company's capitalization of certain costs, including inspection and testing, recommending a more detail review.[460]

In rebuttal, Ms. Pfeuffer objected to Staff's recommendation on grounds that historical spend should be the basis on which to forecast future strategic capital need, that use of an average of percentages of underspending is flawed, that 2020 and 2021 spending levels should not be relied on, and that the company has initiated changes to better achieve planned and projected spending.[461] Regarding the measure of underspending, Ms. Pfeuffer testified that the calculation should be on a dollar-weighted basis, "by calculating the total summed investment and deriving the percentage over/underinvestment based on total investments."[462] She presented illustrative calculations in her Schedule FF-1 of Exhibit A-41 to show the potential differences between averaging two annual calculations and taking an overall average of underspending.

In its brief, DTE relies on Ms. Pfeuffer's rebuttal testimony and Exhibit A-41, objecting to reliance on historical spending for the reasons discussed in connection with Mr. Coppola's testimony, objecting to Staff's calculation of a 15% underspending percentage, contending that this approach ignores unique circumstances in 2020 and 2021, and further asserting that it has instituted changes that will improve its planning

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[460] 8 Tr 5411-5413.
[461] 4 Tr 421-422, also referencing her testimony at 4 Tr 406-408.
[462] 4 Tr 407-408.

and project execution.[463] Staff cites the portion of the Commission's order in Case No. U-20561 explaining the Commission's reluctance to cut strategic capital funding and its expectation that the company would use dollars approved in rates for strategic capital for the purpose approved rather than shifting the capital expenditures to reactive categories.[464] Staff argues the company has yet to reverse the historic trend the Commission considered in that case, citing Mr. Becker's table at 8 Tr 5409. Staff cited Mr. Coppola's characterization of the company's expense projections as a "dramatic escalation," and then addressed Ms. Pfeuffer's rebuttal at length.[465] Staff argues DTE has yet to demonstrate its ability to spend at projected levels, and argues that its historic percentage calculation is reasonable and appropriate. Regarding Ms. Pfeuffer's calculation in Schedule FF1, Staff argues: "The Company's method is a sum of the projected and actual spend over a period greater than a year and does not effectively reflect spend over a given 12-month period."[466] Staff also disputes that a small project will have an outsized effect, noting the similarity between the company's calculated percentage and Staff's.[467] Staff also disputes that the pandemic in 2020 or level of storms in 2021 make 2020 and 2021 unreliable measures, and contends that the Commission order was clear and that DTE did not comply:

> If the Company's projected levels are approved, customers bear the risk of paying for benefits not received if the strategic capital spend is not met. It is not the intent to challenge the Company to spend in strategic capital at any cost, rather a challenge to spend at projected levels in a safe, prudent, and cost-effective manner that provides reliability benefits customers need and deserve. It is not reasonable and prudent to place

[463] DTE brief, 55-58, 61.
[464] Staff brief, 29.
[465] Staff brief, 30-34.
[466] Staff brief, 32.
[467] Staff brief, 32-33.

> projected 2022 and 2023 spend in customer rates that are nearly double 2021 spend levels with the underspend track record. The Company can recover spend beyond Commission approved amounts in future rate cases after showing spend is reasonable and prudent.[468]

In its reply brief, DTE renews its objection to Staff's projection, again urging if an average is to be used, it should be a weighted average. It characterizes Staff's response to Ms. Pfeuffer's rebuttal as not substantive, further contending that Staff's arguments are inconsistent.[469]

Similar to the discussion of the Attorney General's recommendation above, Staff's recommendation is reasonable under the circumstances. Staff's analysis does not unduly weight small projection errors, but instead, Staff has looked at the projections the company has made for the entire subcategory of infrastructure resilience and hardening.[470] It is appropriate to consider the percentage overprojections from year to year, rather than looking at overall average over multiple years. Even looking at these numbers on an overall average basis, the result is still approximately a 15% overprojection. This PFD finds that Staff's recommendation should be adopted, with the additional adjustments to the 4.8kV hardening and pole and poletop maintenance and modernization program adjustments discussed below in subsection ii and iii.

ii. 4.8 kV hardening (B5.4, page 8, line 9)

The 4.8kV hardening program has been addressed and approved by the Commission in prior cases. Ms. Pfeuffer explained the company's hardening program:

> The 4.8kV Hardening program was developed to address the aging 4.8kV system. The program's scope is described below:

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[468] Staff brief, 33-34.
[469] DTE reply, 34.s
[470] 8 Tr 5411. [2020 underspend calculation: $17.895 million / $184.930 million = 9.7%; 2021 underspend calculation: $46.268 million / $233.700 million = 19.8%]

> 1) Test all utility poles that have Company equipment attached and replace or reinforce those poles as needed;
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> 2) Replace wooden crossarms with fiberglass crossarms;
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> 3) Remove Detroit Public Lighting Department (Detroit PLD) arc wire from Company-owned equipment and ensure the remaining Company wires are left in a safe configuration;
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> 4) Remove Detroit PLD distribution wire from Company-owned equipment when it can be confirmed that the wire is not serving customers;
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> 5) Remove service lines to abandoned properties;
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> 6) Trim trees as required to support construction activities;
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> 7) Perform any additional necessary work as dictated by field conditions; and
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> 8) Conduct pilot project to remove primary conductor in sparsely populated areas (deconductoring).[471]

Ms. Pfeuffer discussed the prioritization of the circuits for hardening,[472] and the ramp-up in the program since its inception in 2018, with an increase in projected miles to be hardened from 195 miles in 2021 to 350 miles in 2022.[473] She explained that DTE plans this to be a 10-year program that hardens over 2,200 miles and 85% of the City of Detroit.[474] She testified that the program "has proven very effective in improving the safety and reliability of one of the oldest parts of the Company's electrical grid,"[475] and explained the company's evaluation of the program's effectiveness:

> The Company reviewed the three-year historic average for reliability and wire downs of the circuits hardened prior to the year hardened and

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[471] 4 Tr 291.
[472] 4 Tr 292-293.
[473] 4 Tr 293-294.
[474] 4 Tr 297-298. As shown in Figure 13 at 4 Tr 294, DTE projects it will have completed over 2,000 miles by 2025.
[475] 4 Tr 294.

> compared those numbers to the year after hardening. The Company also reviewed the three-year historic average for reliability and wire downs for circuits in the City of Detroit, the control group, that were not hardened and did not receive tree trim in that time period. Three key metrics were looked at to determine the effectiveness of the 4.8kV Hardening: (1) All-Weather SAIFI (System Average Interruption Frequency Index), (2) SAIDI excluding-MEDs, and (3) Wire Downs.[476]

She presented the data in Figures 14 through 16 of her testimony to show improvements in the all-weather SAIFI, SAIDI excluding major event days, and wire down events relative to the control group.[477]

Consistent with his testimony regarding guiding principles, Mr. Ozar addressed these prior orders, testifying that the Commission's prior orders did not grant blanket approval to "limitless spending" beyond the 2020 test year in Case No. U-20561. Mr. Ozar considered this program an example of his concern with the company's "proactive" replacement policy:

> The difference between proactive replacement and preemptive replacement is highly relevant, as this difference is a core factor driving up distribution system capital program costs, in my opinion. A striking example of proactive replacement is the replacing of all wooden crossarms with fiberglass crossarms in a circuit, as in DTE's 4.8kV Hardening program. Just because a crossarm is constructed of wood does not mean it is at risk of imminent failure. The proactive replacement of wooden crossarms has a multiplying effect on asset replacements in light of the fact that all the pole top equipment attached to the cross arm is then replaced. Another example is that old ceramic insulators are replaced with polymer insulators. Although polymer insulators may have greater durability characteristics over ceramic insulators, ceramic insulators do not have a design defect on the basis of being made of ceramic material, nor are they at risk of imminent failure just because they are old. Ceramic fuse cutouts are also replaced with polymer cutouts, and so on. The consequence is that capex can swell with the implementation of "proactive" replacement policy.[478]

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[476] 4 Tr 295-296.
[477] 4 Tr 296-297.
[478] 8 Tr 3963.

Mr. Ozar further explained his opinion that DTE did not meet its burden in this case to establish that the company's proposed spending on this program is reasonable and prudent. Mr. Ozar looked at the increases in spending on this program from 2018 actuals through the company's projected 2023 spending. He also looked at the analysis the company presented to support the reasonableness and prudence of the hardening program expenditures. Mr. Ozar concluded that DTE's studies comingled the effects of line clearing and the capital replacements in the program, and that worsening data for the control group did not control for the effects of tree trimming, but likely reflected no tree trimming within many years:[479]

> I reviewed detailed data provided by the Company in response to discovery regarding the last time the circuits in the control group were trimmed. Of the 55 circuits in the control group for which DTE provided last trim data, 42 had not been trimmed since 2012 or earlier; 8 were last trimmed in 2014; 3 were trimmed in 2015; and 2 were trimmed in 2019. None are scheduled to be trimmed again until 2022 or later. All 28 of the hardened circuits were trimmed in 2019 or later. Comparing reliability differences between the control group circuits, 76% of which had not been trimmed for at least 9 years by the "1-year after" period, to hardened circuits that had all been trimmed within 2 years of the "1-year after" period, is demonstrative of the value of trimming and not much else.[480]

He also testified that DTE prioritized lines with the worst reliability for hardening.[481] Specifically regarding the wooden cross-arm replacement, he testified that DTE has not demonstrated that they fail or cause significant outages and reviewed data on outages caused by equipment failures.[482] He also testified that replacing the cross arms likely produces de minimis safety benefits. Mr. Ozar also noted a lack of data on substation-area hardening costs for 2020. Mr. Ozar recommended that the Commission limit

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[479] 8 Tr 3972-3976.
[480] 8 Tr 3975.
[481] 8 Tr 3976-3977.
[482] 8 Tr 3978-3981.

expenditures on this program to 2021 levels, and that DTE be directed to develop an improved analysis of the effectiveness of the program.[483]

In rebuttal, Ms. Pfeuffer contended that Mr. Ozar failed to understand the purpose of the program. She agreed in part with his characterization of the program as an interim measure.[484] She testified that his testimony ignores the fact that DTE performed an analysis in Case No. U-20162, discussed at 4 Tr 729-730 in that docket, which found the scope of work in the hardening program to be the most cost-effective way to address safety and reliability in Detroit.[485] She reiterated the potential cost of conversion, also noting DTE's plan to include environmental justice considerations in its distribution system planning.[486] She testified that DTE has hardened over 600 miles to date, emphasizing that these miles are now clear of problematic arc wire, and that hardened circuits saw improvements in performance.[487] She also considered Mr. Ozar's analysis as overlooking that the program targets safety as well as reliability, citing the factors used to prioritize circuits for hardening.[488] She also cited a table in Mr. Ozar's testimony at 8 Tr 3978 to show that the program has been more effective than tree trimming alone:

> MNSC Witness Ozar provides a table, on page 25 of his testimony, that shows that hardening has been equally successful at improving All-Weather SAIFI, and approximately 47% better at reducing SAIDI ex-MEDs, and approximately 56% better at reducing wire downs compared to tree trim alone. This proves that the 4.8kV Hardening program is

[483] 8 Tr 3984.
[484] 8 Tr 423.
[485] 4 Tr 423-424.
[486] 4 Tr 424-425.
[487] 4 Tr 426.
[488] 4 Tr 426-427.

> substantially better at improving safety and duration of customer outages in non-MED situations.[489]

She emphasized that arc wire removal alone would leave the cross arms "dangerously unbalanced."[490]

In related testimony, Dr. Wang expressed a concern that DTE had not adequately investigated the cost of conversion:

> Staff also finds the Company's estimated cost to convert the 4.8kV system comes from an incomplete analysis and may be high. The Company analyzed limited alternatives before proposing to harden the 4.8kV system instead of replacing it. In the City of Detroit, 4.8kV system conversion is projected to cost over $4 billion dollars and over a decade to replace. Full conversion of the Company's 4.8kV system is estimated to be over $30 billion and require multiple decades. Though the Company determined the 4.8kV hardening program provides safety and reliability improvements at a faster pace and more affordable cost than alternatives, the alternatives it considered were severely limited. These were to "do nothing and allow the system to deteriorate" or take decades to convert the 4.8kV system before communities experience any widespread increases in system reliability. With the increasing use of DERs such as solar, storage, energy efficiency, and microgrids, there may be alternatives to the 4.8kV hardening program beyond the two the Company considered.
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> The Company also indicates that it has not estimated the costs to convert the 4.8kV system with and without completing 4.8kV hardening first. If the Company's estimated cost to convert the 4.8kV system includes the cost to first harden it, as well as to implement overhead fiber trunks and backbones to 4.8kV substations, the cost may be higher than converting the 4.8kV system expeditiously without such efforts. A detailed analysis would be required to confirm.

She explained that Staff recommends that the Commission require DTE to work with Staff and intervenors on a more comprehensive analysis of alternatives for the 4.8kV system within DTE's metro Detroit fiber loop in its next rate case, while also pursuing a

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[489] 4 Tr 427.
[490] 4 Tr 428.

greater analysis of the impacts of infrastructure investments on communities and the ability to incorporate socioeconomic data as part of its analysis.[491]

Mr. Koeppel also testified regarding the company's 4.8kV hardening program. He looked at the long-term effects of the hardening program:

> The 4.8 kV Hardening program will delay conversion of these circuits to 13.2 kV, leaving the predominantly low-income communities in Detroit, Highland Park, Hamtramck, and suburban and rural Michigan with sub-par infrastructure for multiple decades. Delay reinforces the current gap in service quality over the long term. Delay also amplifies existing wealth inequalities by limiting opportunities to deploy emerging technologies such as electric distributed generation, distributed storage, and electric vehicles that would bring benefits to individual owners and their communities at large.[492]

Mr. Koeppel presented various comparisons of the 4.8kV system to the 13.2kV system. He discussed the concept of "hosting capacity," citing a DTE discovery response in Exhibit DAO-69 to show that the 4.8kV system imposes greater limits on the ability of residents to add DG. He also compared the average asset age, citing Exhibit DAO-71, and various reliability measures, citing an exhibit from Case No. U-20162.[493] As did Mr. Ozar, Mr. Koeppel objected that the reliability benefits DTE attributes to hardening may reflect tree trimming.[494] Mr. Koeppel also addressed Ms. Pfeuffer's testimony that 29% of the company's projected strategic capital spending will be spent in Detroit, which represents only 14% of the company's customers. In his view, DTE's hardening program is simply a relabeling of normal maintenance DTE has fallen behind on, and he

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[491] 4 Tr 5253-5254.
[492] 8 Tr 4308.
[493] 8 Tr 4311-4316.
[494] 8 Tr 4317.

also noted DTE's willingness to shift spending or reprioritize spending after its rates are set.[495] He urged the Commission to focus on outcomes rather than spending amounts:

> Because of historic underinvestment and current inequities, a determination of what capital investments are reasonable and prudent must be based on the outcomes for those communities and the rate base as a whole, not on the actual dollars invested in each community in this case alone.[496]

He recommended that the Commission reject the company's hardening program as written, and require DTE to return with a plan that has an accelerated timeline for conversion, an analysis that demonstrated equity in terms of access to emerging technology and service quality, and a compensation mechanism "to address gaps in service quality."

Dr. Wang also addressed hosting capacity in her discussion of grid equity:

> Without 4.8kV conversion, the communities served by the 4.8kV system will be severely limited in participating in the clean energy future. The 4.8kV hardening program provides improved reliability and safety in the short term. However, without converting the 4.8kV system to higher voltages, its communities will be limited or barred from utilizing energy technologies like electric vehicles, other electrification technologies, solar, and storage. Electric vehicle (EV) adoption and other increased load can thermally overload 4.8kV system conductors and lead to voltage drops. In a future with more DERs, challenges in remote monitoring and control in the 4.8kV system will only be exacerbated by the dynamic and unpredictable DER loading patterns concentrated on a circuit. The Company concludes that "as customers adopt newer technology such as EVs, rooftop solar, and storage, a capacity constrained system will struggle to keep pace with customer needs." Hosting capacity is proportional to the load served by a circuit and generally larger for 13.2kV circuits. A 4.8kV circuit has an average day-to-day rating of 3.4 MVA, while a 13.2kV circuit has an average day to day rating of 11.6 MVA. In other words, a 13.2kV circuit has 3.4 times more capacity than a 4.8kV circuit, all else equal.

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[495] 8 Tr 4321.
[496] 8 Tr 4321-4322.

Communities served by 4.8kV are plagued by the highest trouble in the DTE Electric system, yet the very system that causes the increased trouble is also the one that limits their ability to seek solutions. The 4.8kV system constrains not only much needed reliability and resiliency solutions, like solar and storage. It also constrains electrification benefits. The Company touts the environmental benefits from EVs, which emits 55% less greenhouse gases than a traditional gasoline vehicle in Michigan per year, as one justification of its EV program. In a study of 53 metropolitan statistical areas in the U.S., Detroit had the 16th highest estimated benefit from replacing internal combustion engine (ICE) vehicles with EVs. The benefits from air quality improvements in Detroit from EV adoption was estimated to be about 5.7¢/mile or $8,600 per 150,000 miles. However, much of metro Detroit is part of the Company's 4.8kV system. Though the communities within the metro Detroit fiber loop have some of the highest relative community environmental risk factors in the Company's service territory, higher use of ICE vehicles may persist in the metro Detroit area. All else equal, the metro Detroit communities with 4.8kV systems simply cannot adopt the number of EVs possible on 13.2kV systems. These metro Detroit communities that need the air quality and health benefits of EVs the most within the Company's service territory may be disadvantaged because they have 3 4.8kV systems.

Slow conversion of the 4.8kV system to higher voltages perpetuates infrastructure inequities into the future. Even though the Company's scenarios for grid modernization, "specifically the electrification and distributed generation scenarios, identified the potential need to convert the 4.8kV system to a higher voltage at an accelerated pace",286 8 the Company plans to develop a 4.8kV conversion plan in an iterative process and to '[prioritize]…circuits/substations for conversion in the five to 15 year timeframe." This suggests that completion of 4.8kV conversion of some circuits and substations may not occur until 15 years later or more. The Company suggests that full conversion of the 4.8kV system may span multiple decades. Some communities served by the 4.8kV system will likely have to endure its limitations for multiple decades until it is converted.[497]

In rebuttal, Ms. Pfeuffer testified that the company shares Mr. Koeppel's and Dr. Wang's concerns regarding hosting capacity in part:

Most of the witnesses quote the Company's own DGP where we say "the constraints of the 4.8kV system make it incompatible with some of the requirements of grid modernization," specifically when it comes to less

[497] 8 Tr 5249-5251

> capacity to serve load and the challenges of managing unpredictable loading patterns of high concentrations of DERs. (See Exhibit A-23, Schedule M1, p 314). Most areas of the 4.8kV system currently have sufficient capacity to incorporate EVs and additional DERs. Conversion projects currently take place in areas that have capacity limitations. Future planning and analysis efforts will help determine when the areas of the 4.8kV will need to be converted to meet projected grid needs.[498]

She took issue with Mr. Koeppel's comparison of the hosting capacity of 4.8kV circuits compared to 13.2kV circuits, contending that the hosting capacity measure needs to be normalized by the number of customers, testifying that the 13.2kV circuits may serve 3 times the number of customers. She presented revised calculations showing that on a per-1000 customer basis, the 4.8 kV circuits have an average hosting capacity of 227 kW while the 13.2 kV circuits have an average hosting capacity of 722 kW.[499]

Ms. Pfeuffer disputed that hardening would delay conversion, testifying:

> Witness Koeppel incorrectly believes that the 4.8kV hardening program, which is providing valuable safety and reliability benefits to the residents of Detroit, will delay the conversion to 13.2kV. He believes this delay, which does not in fact exist, "amplifies existing wealth inequalities by limiting opportunities to deploy emerging technologies such as electric distributed generation, distributed storage, and electric vehicles that would bring benefits to individual owners and their communities at large." (Koeppel, page 53 lines 18-21.) The conversion program timing is not delayed by hardening, as discussed elsewhere in my rebuttal testimony. Rather, conversion program timing is primarily driven by capacity constraints on the distribution system, and capacity constraints are what need to be addressed to enable deployment of high concentrations of EVs and DERs. Very few areas covered by the 4.8kV Hardening program currently experience capacity constraints. Substation areas, which do, such as Hawthorne and Villa, have a conversion project beginning in the test year to address these constraints. Details on these projects are included in Exhibit A-23, Schedule M5, pages 260-263 Customers served by the 4.8kV distribution system do in fact today have access to EV charging and distributed generation, which is also discussed elsewhere in my rebuttal testimony.[500]

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[498] 4 Tr 509.
[499] 4 Tr 519-520.
[500] 4 Tr 518-519.

Ms. Pfeuffer also addressed concerns Mr. Koeppel raised regarding Highland Park in particular, citing all-weather SAIFI and SAIDI data for 2021 to show performance above average in Highland Park.[501]

Several parties testified that DTE had not worked with the MiEJScreen tool under development by EGLE. Ms. Pfeuffer also addressed witness testimony regarding the MiEJScreen tool. In response to Dr. Wang's testimony, Ms. Pfeuffer testified that the draft tool DTE had access to was not intended to be final, but indicated that she expects the final version will also "show that parts of Detroit and some communities near Detroit will be identified as communities with a high MiEJScreen score, i.e. as environmentally damaged communities. She testified that DTE identified some gaps in the accuracy of the draft tool, "including an acknowledgement that the U.S. census has a clear undercounting of Black, Indigenous, and People of Color (BIPOC), the BIPOC definition used for the Census excludes some demographic groups including people of middle-eastern or north African descent."[502] She testified that the company has begun to develop an ability to overlay reliability data with the geographical areas of the MiEJScreen as discussed in the DGP, but further testified:

> Refinement and implementation of this EJ plan will need to occur after the MiEJScreen is updated and finalized, and the Company gains experience with its application in the context of electric reliability data. As acknowledged on the MiEJ Screen fact sheet, "The screening tool is a useful first step in understanding or highlighting locations that require further review. It is important to understand that screening tools do not provide a complete assessment of risk and have significant limitations." (MiEJScreen Factsheet (Michigan.gov).[503]

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[501] 4 Tr 520-521.
[502] 4 Tr 510.
[503] 4 Tr 511.

Ms. Pfeuffer also commented on the map overlay Dr. Wang presented, noting areas of high impact outside the fiber ring as well as areas with lower draft MiEJ scores inside the ring.

Stating the company's commitment to complete an analysis of the reliability of communities identified by the MiEJScreen tool, and to "develop a comprehensive [Energy Justice] plan for distribution to address the most impacted communities who also experience lower reliability,"[504] she acknowledged witness testimony specifically addressing reliability impacts on low-income households, including testimony from Mr. Jester and Ms. Lowe.[505]

Further regarding the MiEJ tool and future work by the company, she testified

> Based on an analysis of the MiEJScreen and a geographic view of the Company's reliability data, the Company intends to develop and then file a distribution-related EJ plan in either the next Distribution Grid Plan or Rate Case.[506]

She similarly addressed Mr. Kenworthy's testimony that in this rate case filing, DTE had not reflected the EJ commitments contained in its DGP. In addition to referencing the company's plans for future cases, she cited programs "targeted at what in the future will likely be identified as MiEJScreen impacted communities and in particular Detroit," including: the 4.8kV hardening program, tree trimming, the CODI Detroit Infrastructure program, the company's "commitment to convert all of the 4.8kV system, in the 2021 DGP," currently planned conversions, and the NWA O'Shea battery project for the O'Shea urban solar park.[507]

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[504] 4 Tr 513.
[505] 4 Tr 512-516.
[506] 4 Tr 516.
[507] 4 Tr 517-518.

In its brief, DTE reviews Ms. Pfeuffer's direct and rebuttal testimony, identifying the 4.8kV hardening program as reducing the risk associated with downed power lines.[508] Responding to Mr. Ozar's concerns, DTE cited Ms. Pfeuffer's testimony at 4 Tr 292 and 427 to show that Mr. Ozar wrongly assumed DTE targeting worse performing circuits for hardening, while instead DTE targets safety (wires down and foot traffic) in addition to performance and reliability. DTE also pointed to Ms. Pfeuffer's testimony that the arc wire cannot simply be removed without balancing the cross arms. The company argues: "The 4.8kV Hardening program is fully developed, well supported in past cases, efficient, and providing immediate safety and reliability benefits for customers."[509]

Based on Mr. Ozar's testimony and additional discovery responses from DTE, MNSC argues that the Commission should limit the 4.8kV hardening program to its 2021 level, and require DTE to conduct additional analysis to demonstrate that the hardening program offers reliability benefits over tree trimming that justify the additional expense.[510] It relies on Mr. Ozar's analysis in explaining that DTE did not use a proper control group in evaluating the hardening program, since the control circuits had not been trimmed in many years. MNSC argues that although the Commission approved the program in prior rate cases, it was too soon then for the company to have effectiveness data from the program. It argues this is the first rate case to consider such evidence, and the first opportunity to consider the cost-effectiveness of the program. It

[508] DTE brief, 54.
[509] DTE brief, 63.
[510] MNSC brief, 33-52.

also notes DTE's proposal to significantly increase its annual spending on the program.[511]

MNSC addresses DTE's argument that as part of hardening, it is removing arc wire as required by the Commission. It argues that the Commission has not actually ordered to DTE to remove arc wire, reviewing the Commission's orders in Case No. U-18484, along with DTE's arguments in that case:

> There was no directive in U-1848 to remove arc wire. To the extent the Commission approved and may continue to approve ratepayer investment in hardening in rate cases, DTE agreed the program would include DPLD arc wire removal because that would be more cost effective than conversion, arc wire removal alone, and other approaches considered. At the same time, DTE was clear that hardening "will also allow for the removal of DPLD arc wire where it is co-located with DTE Electric's assets, though the removal of arc wire is not the primary driver nor the primary benefit of this program." It is now illogical for the Company to support approval of its proposed ramp-up in hardening because it also will remove co-located arc wire it comes across in the process. The Company must demonstrate that hardening is a cost-effective way to maintain the distribution system to prevent safety risks, including downed wires – arc or otherwise. Removing arc wire may be a benefit of hardening, but it does not convert hardening into a reasonable and prudent ratepayer investment.[512]

In support of its argument that arc wire is not the primary purpose of DTE's hardening program, MNSC cites cross-examination of Ms. Pfeuffer at 4 Tr 566-577 and Exhibits MEC-90, MEC-91, MEC-92, MEC-105, and A-23, Schedule M1 (page 186) in arguing that DTE does not clearly track arc wire removal.[513]

While emphasizing its support for safety and reliability improvements for the part of the distribution system that is in environmental justice communities, MNSC argues that DTE has not established that its program improves safety or reliability relative to

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[511] MNSC brief, 36-39.
[512] MNSC brief, 43.
[513] MNSC brief, 43-45.

enhanced tree trimming because it did not establish a proper control group. Further, in response to DTE's contention that it can rely on reductions shown by its tree trimming program generally in comparison to the hardening program results to show a greater reduction in wires down and in SAIDI ex-MEDs, MNSC cites DTE's 2021 tree-trimming report in Exhibit MEC-97. It argues that the 2021 report shows a reduction in wires down equivalent to the reduction DTE attributes to its hardening program. Acknowledging a lower (55% versus 66%) reduction in SAIDI ex-MEDs in the general tree trimming program results relative to the hardening results, MNSC cites Ms. Hartwick's testimony at 7 Tr 2296 regarding the variability of SAIDI ex-MEDs relative to SAIFI, because the minutes of interruption are affected by other factors such as crew availability, travel time, outage prioritization, and accessibility.[514] MNSC also urges the Commission to require DTE to present an effectiveness study in a future case seeking additional funding for its hardening program.

DAAO argues that hardening is significantly less reliable than conversion, deprives communities of access to clean energy solutions, and delays conversion, citing Mr. Koeppel's testimony.[515] It argues that DTE's reliance on its capacity need determinations in prioritizing circuits for conversion is discriminatory. DAAO urges the Commission to require DTE to develop an accelerated plan for 13.2 kV conversions that addresses gaps in service quality.

In addition to its other recommendations for DTE to develop its consideration of equity in future cases, Staff argues that DTE should provide a more comprehensive

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[514] MNSC brief, 48-49.
[515] DAAO brief, 11-33.

analysis of alternatives for converting the 4.8kV system within the company's metro-Detroit Fiber ring in its next rate case.[516] Staff addresses DTE's rebuttal to Dr. Wang's discussion of equity, citing the safety and reliability concerns with the 4.8kV circuits.

In reply to MNSC, DTE repeats the arguments made in its initial brief,[517] and further responds that MNSC "adds additional layers of contentiousness, but ultimately makes no meritorious point."[518] It does not directly challenge MNSC's argument that the Commission did not require DTE to remove arc wire, but states: "[T]he Commission has indicated its expectation that DTE Electric remove the old DPLD arc wire."[519] DTE cited the Commission's December 7, 2017 order in Case No. U-18484, page 5, and its March 15, 2018 order in the same docket, page 6.

DTE also addresses DAAO's argument in its reply, arguing that its concerns were largely addressed in the Commission's order in Case No. U-20561.[520] DTE also cites Ms. Pfeuffer's more general testimony regarding environmental justice—discussed above, and her testimony addressing what DTE considers misperceptions regarding hosting capacity and that hardening will delay conversion. It also reiterates its 14%/29% argument.[521]

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

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[516] Staff brief, 282.
[517] DTE reply, 38.
[518] DTE reply, 38.
[519] DTE reply, 38.
[520] DTE reply, 38-39.
[521] DTE reply, 39.

hardening analysis. It is surprising that DTE is so anxious to proceed with an expansion of this program given its error. While DTE relies on unrelated studies of the effectiveness of tree-trimming, there is no data showing how the untrimmed circuits in DTE's tree-trimming study compared to the untrimmed circuits in the hardening control group, most of which had not been trimmed for at least 7 years prior to the hardening, with additional time before the data was taken. As MNSC argues, DTE should present a proper analysis of the efficacy of hardening relative to enhanced tree-trimming before seeking to expand or continue the hardening program in a future case. Mr. Ozar described the analysis as follows:

> What is needed is both cost and reliability/resilience data of replaced assets on a decoupled basis (from tree trimming) so as to enable the determination of the effective cost of improvements -- $/SAIDI, $/SAIFI, $/wire downs. To be complete, the Company should demonstrate the reasonableness of its proposed increase in Hardening spending by showing the incremental cost of reliability improvement on a decoupled basis. A complete analysis would also incorporate the projected benefits or spending reductions expected from investments in emerging and strategic spending.[522]

While not dispositive as to the merits of DTE's program, this PFD finds MNSC's argument that the Commission never ordered DTE to remove arc wire in Case No. U-18484 well supported.

Recognizing that this PFD recommends that the Commission accept Staff's overall 15% reduction to expenditures in this category, the additional adjustments this PFD recommends assume this line item is first reduce by that 15%, and the additional adjustments move the test year expense projection to $68.2 million and move the 10-month bridge projection to 10/12ths of that amount, or $56.8 million. The approximate

[522] 8 Tr 3982.

magnitude of the adjustments are $25.2 million for the bridge period and $28.9 million for the test year.

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

iii. Pole and poletop maintenance and modernization (B5.4, page 8, line 10)

Ms. Pfeuffer described this program, explaining that "modernization" had been added recently to the program title:

> This program proactively identifies and replaces damaged or defective equipment before unexpected failures occur. The PTMM (Pole and Pole Top Maintenance and Modernization) program is designed to catch these issues prior to failures. This program was called the Pole Top Maintenance (PTM) program in the past, but with an enhanced specification that replaces old and outdate components with components of an enhanced specification, the term "Modernization" was added to the title. The enhanced specifications include higher grades of materials and updated more reliable design for individual components.[523]

In addition to the company's increased pole and equipment standards, also noted above, Ms. Pfeuffer testified that as part of this program, the poles would also be inspected for below-grade decay "and treated to prevent the spread of the decay on

[523] 4 Tr 301.

poles that are within guidelines for reinforcement."[524] Ms. Pfeuffer discussed the wear and tear on poles and pole top hardware from exposure to harsh conditions. She also cited benchmarking with four utilities that inspect pole top equipment on a four or five-year cycle, and poles on a 5-to-10-year cycle. She testified that DTE currently inspects both poles and hardware on a 10-to-12-year schedule, and plans the increased investments to move to a 10-year cycle by 2025, with the further goal of achieving a 5-year cycle in the future.[525] She credited DTE's "Customer Excellence" program focused on customers with multiple outages for DTE's additional learning that many of the underlying reliability issues would have been resolved through a short pole maintenance cycle. She testified that outages related to overhead equipment are responsible for 25% of all events, and that DTE expects to see "a reduction in equipment related outage events that will drive reliability improvements, reduce reactive costs, and improve the safety of the system."[526]

Mr. Ozar recommended that the Commission disallow $15.7 million from the 10-month bridge period projection and $54.3 million from the test year projection for this program.[527] He also considered this program an illustration of his concern with proactive replacement of equipment, discussed above. Citing information DTE provided in discovery, he testified:

> [C]ontractors test poles along a circuit following the Company's Wood Pole Maintenance Specification and inspect pole top equipment following the Company's Pole Top Maintenance Specification. These specifications require the contractor to test the strength of the pole, assess poles for damage and decay, and identify defects in pole top equipment such as

[524] 4 Tr 304.
[525] 4 Tr 301-303.
[526] 4Tr 305.
[527] 8 Tr 3985-3998.

> oversagging or missing cross-arm bolts. Following inspection, pole reinforcement and equipment replacements are implemented.[528]

He then indicated that the company denied conducting repairs (as opposed to replacements) based on the inspections within this program, citing DTE's discovery response in Exhibit MEC-26.[529]

Mr. Ozar noted that the earlier version of this program had already incorporated enhanced equipment and an increase in the minimum pole class for primary voltage wire. He concluded that the more rigorous testing was the primary new feature of the program.[530] Mr. Ozar reviewed the increases in the planned spending for this program, nearly doubling the $32 million level in 2021 to $59 million in 2022, and almost tripling the 2021 level to $94 million in 2023, followed by additional increases of approximately 25% in 2024 and 2025.[531] Reviewing data on the company's pole inspection efforts since 2017, Mr. Ozar concluded that the company had generally been maintaining a 10-to-12-year inspection cycle, and should not need to double or triple its expenditures.[532]

Looking at data on the inspection component of the program expenditures, Mr. Ozar concluded that inspection costs are a modest part of the program, while "it is 'modernizing' these lines that drives costs."[533] He presented data to show the relative costs of inspections, reinforcements, and "modernizations," with the modernizations accounting for more than 80% of the total cost. Looking at historical and projected circuit counts, line miles, and pole numbers that have been or are planned to be

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[528] 8 Tr 3986.
[529] 8 Tr 3986.
[530] 8 Tr 3987-3988.
[531] 8 Tr 3988.
[532] 8 Tr 3989-3990.
[533] 8 Tr 3991.

inspected, Mr. Ozar further concluded that the company plans to inspect 10% more poles in 2023 than it did in 2018, at an additional cost of approximately $60 million.[534] Mr. Ozar reviewed additional information provided by the company in discovery in concluding that the company had not justified the additional spending projected for the bridge and test year.[535] Looking at a table of circuits, miles, and poles inspected and planned to be inspected from 2018 to 2023, he testified: “This table indicates the Company plans to inspect only about 10% more poles in 2023 than it did in 2018, and address about 376 fewer line-miles in 2023 than in 2018. Yet the Company proposes to invest $58 million more in 2023 ($94 million) than in 2018 ($36 million).”[536] Mr. Ozar disputed that the pole top equipment DTE is targeting in this program is the same type of equipment responsible for the 25% of outages Ms. Pfeuffer referred to:

> [M]ost of those equipment-related outages are either of unknown cause or are related to conductors (which are not included in the Pole/PTMM program). For the circuits included in Pole/PTMM program in 2020 and 2021, DTE data shows that all equipment collectively accounted for a fraction of outages on these lines.[537]

Mr. Ozar also questioned the company’s cost projections for this program generally, testifying that “the Company has so deeply buried the cost components for ‘line modernization’ that it is near impossible to establish the reasonableness of the request,” and specifically for 2023, testifying that DTE had not yet identified circuits the program would target in 2023.[538] He recommended that the Commission limit the projected costs to the 2021 spending level for this program, and require the company to provide further

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[534] 8 Tr 3991.
[535] 8 Tr 3992-3997.
[536] 8 Tr 3991.
[537] 8 Tr 3995.
[538] 8 Tr 3996.

justification before any expansion.[539] Mr. Ozar also testified that a 5-year pole inspection program should save money through remediation rather than replacement.

In rebuttal, Ms. Pfeuffer objected to the proposed limit on projected spending for this program. She cited the DGP (Exhibit A-23, Schedule M1) at page 222 to confirm the current 3-year average pole inspection cycle of 10.9 years, and explained that the company's goal is to reduce the cycle to 10 years without reliance on other programs.[540] She identified four reasons for the 10-year goal: hardening will end in 2026; the company is adopting a more robust standard of inspection "whereas the other inspections are less comprehensive visual inspections of the pole only"; this standard is supported by benchmarking; and Staff has recommended an inspection cycle between 10 and 12 years. She testified that the company has changed its pole inspection process to specify pole testing for poles 20 years and older, and with increase in testing, "the Company has identified more poles requiring remediation," which requires additional capital to replace or reinforce those poles.[541] Ms. Pfeuffer disputed Mr. Ozar's conclusion that the increase in minimum pole standards should not have a significant effect on costs, stating that only 12% of the poles currently on the company's system meet the higher specifications.[542] She reiterated that these specifications increase the strength of poles by a factor of more than 2.5. She noted Mr. Ozar's recommendation for a shorter inspection cycle has to confirm the importance of the program.

In its brief, DTE relies on Ms. Pfeuffer's testimony, reiterating that the company's goal of a 10-year cycle reflects its plans to end the hardening program in 2026, which

[539] 8 Tr 3997.
[540] 4 Tr 428-429.
[541] 4 Tr 431.
[542] 4 Tr 431-432.

will reduce the number of poles inspected, emphasizing its new “more robust” standard, and citing benchmarking and Staff’s 10-12-year cycle recommendation.[543] It argues additional capital costs are required because poles are being inspected for below-grade decay and the new pole specifications have increased strength and only about 12% of the poles currently meet those standards.[544] DTE repeats these arguments in its reply brief, and argues that MNSC’s arguments “lack merit particularly when viewed collectively.”[545] It contends that MNSC ignores that the company’s program “proactively identifies and replaces damaged or defective equipment before unexpected failures occur,” citing Ms. Pfeuffer at 4 Tr 301, and further contends that MNSC “suggest that the Company should wait for pole failures before acting.”[546] It notes that nearly 30% of the company’s poles are more than 60 years old, with a life expectancy of 40-60 years.

MNSC argues based on Mr. Ozar’s testimony that the company’s 10-year inspection cycle does not justify the projected spending increases. In addition to Mr. Ozar’s analysis, MNSC additionally cited DTE discovery responses in Exhibit MEC-101 showing a significant reduction in the number of poles reinforced relative to the number replaced in 2020 and 2021, but also showing projected pole replacements not exceeding historic levels from 2019. MNSC argues that DTE did not establish that the program is cost-effective.

In its reply brief, DTE reiterates the points in its initial brief, and argues MNSC’s arguments “lack merit particularly when viewed collectively.” DTE argues that MNSC ignores the company’s evidence of additional testing and increased pole specifications.

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[543] DTE brief, 64-65.
[544] DTE brief, 65.
[545] DTE reply, 40-41.
[546] DTE reply, 41.

It contends that MNSC's concern that the new inspection standard does not justify the increased costs is "speculative," and "neglects the present cost of additional remediation." Then, DTE argues:

> MNSC does not dispute the higher pole specifications, but instead suggests that "there is no demonstration that poles are failing and requiring replacement at a higher rate than historically" (MNSC Initial Brief, p 57). But MNSC neglects that, as the Company said when introducing this topic, the program proactively identifies and replaces damaged or defective equipment before unexpected failures occur (Pfeuffer, 4T 301). Nearly 30% of the Company's poles are now more than 60 years old, with an industry life expectancy of 40-60 years."[547]

DTE then contends that MNSC is suggesting that the company should wait for pole failures before acting, arguing that failing poles put customers and linemen at risk.[548]

This PFD finds Mr. Ozar's testimony persuasive. DTE was not clear regarding its standards for remediation versus replacement. It also has not explained the basis for its cost projections. Looking at the tables in Mr. Ozar's testimony at 8 Tr 3991, the company is projecting an approximately 6% increase in pole inspections between 2022 and 2023, yet is projecting a 60% increase in total cost, and a 70% increase in the "modernization" component of its total cost. The data from Exhibit MEC-101 is further confounding because it seems to show no basis for the company's projected cost increases over 2019 levels. DTE did not refute Mr. Ozar's testimony that the company has been using the upgraded pole class at least since Mr. Bruzzano's direct testimony was filed in Case No. U-20162.[549] Nor did DTE refute Mr. Ozar's testimony regarding the equipment failures that cause outages. Reviewing the evidence, it appears that DTE's program is unsupported by credible projections.

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547 DTE reply 41.
548 DTE reply 41-42.
549 Ozar, 8 Tr 3994 at n84.

Similar to the adjustment above, this PFD computes the additional amount needed to reduce the 10-month bridge and test year projections to an annual expense level of $33.4 million, the 2021 expense level included on line 10 of schedule B5.4, after Staff's 15% reduction is taken into account. The result is an additional reduction of approximately $13.9 million to the 10-month bridge and a reduction of $41.1 million to the test year. To clarify, after Staff's adjustment and the additional adjustment recommended in this subsection, the 10-month bridge expense level included in rate base will be $27.9 million (10/12ths of $33.44 million) and the test year expense will be $33.44 million.

e. Infrastructure redesign and modernization (B5.4, page 1, line 20)

Ms. Pfeuffer described the expenses in this category as "major projects that generally involve the construction of substations and the rebuilding of large portions of circuits,"[550] and that are "often driven by needed capacity additions in growth areas or areas with overloaded equipment."[551] She specifically discussed several of these projects. The company is projecting large increases in spending for 2022 and 2023 in this category, from $49.3 million in 2020 to $215.1 million for the 10-month bridge period and $314.3 million in the test year. Staff recommended an overall reduction as discussed in subsection i below, also addressing two line items of the company's projections, subtransmission redesign and rebuild and the strategic service and undergrounding pilot. The Attorney General and MNSC also address this second line item.

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[550] 4 Tr 313.
[551] 4 Tr 314.

i. Staff overall

Mr. Becker recommended a 40% reduction to the company's projected 2022 and 2023 spending for this category, based on a similar calculation of average underspending for this category in 2020 and 2021 as he performed for the infrastructure resilience and hardening.[552] He testified that Staff's recommended reductions include Staff's specific recommendations regarding both subtransmission redesign and rebuild, and strategic and service undergrounding, discussed in more detail below.[553] Staff's adjustment results in reductions of $71 million to the 2022 bridge period and $86 million to the test year projections in addition to the individual line item adjustments recommended below. Mr. Becker further testified that if the Commission does not agree that the company's projected strategic and service undergrounding expense should be reduced as Staff recommends, Staff's recommended reductions of $71 million and $86 million should be adopted, which are equivalent to an approximately 30% reduction to the expense projections for this category, not including the strategic undergrounding pilot.[554]

Ms. Pfeuffer objected to Staff's recommendation in rebuttal, asserting that historic strategic capital should not be used to forecast the company's future capital need, citing Schedule FF1 of Exhibit A-41 in recommending that the Commission reject use of average of annual underspending amounts, emphasizing that 2020 and 2021 should not be relied on due to the pandemic and extreme storm events beyond the company's ability to control, and pointing to changes the company has made to improve

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[552] 8 Tr 5415-5416.
[553] 8 Tr 5416.
[554] 8 Tr 5417.

its project planning and execution.[555] Regarding the use of averages, she also computed an average underspending amount of 38.3%, as shown in Schedule FF4 of Exhibit A-41, combining the two year expense projections and underspending amounts.

In its brief, DTE relies on Ms. Pfeuffer's rebuttal testimony and Exhibit A-41, as also discussed above in connection with infrastructure resilience and hardening.[556] In its reply brief, it adds that it "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."[557]

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

ii. Subtransmission Redesign & Rebuild: Small projects and reserve (B5.4, page 9, line 13)

After explaining that the subtransmission system is experiencing age and storm related challenges, and increased loading in some areas, Ms. Pfeuffer generally described the company's subtransmission redesign and rebuild program as follows:

> The subtransmission redesign and rebuild program is focused on installing new station equipment, as well as rebuilding both the overhead and underground portions of the subtransmission system. The station work involves the installation of large transformers, capacitor banks and associated equipment, and will provide significant improvements to the system with additional redundancy and voltage support. Th overhead work will be completed to our updated grade B standards which includes the replacement of old wooden poles with new steel poles, porcelain insulators with polymer clamp top insulators, and small aging conductors – which are often damaged by multiple lighting strikes – with larger, stronger conductors able to withstand winds up to 90 mph resulting in a much more

[555] 4 Tr 433-434.
[556] DTE brief, 67.
[557] DTE reply, 43-44.

> storm resilient system. The larger standard conductor will provide significantly more capacity on each circuit, while reducing the magnitude of voltage drop over long distances on the system and providing approximately twice the strength of existing conductors if a tree limb does happen to fall on it. The underground work consists of replacing at-risk or overloaded cable with new sections and rebuilding cable poles to new specifications.[558]

Within the subtransmission redesign and rebuild program, which includes multiple line items on page 9 of Schedule B5.4, line 36 includes projected expense for "small projects and reserve."

Mr. Becker cited the company's discovery response in Exhibit S-15.3, page 5, as explaining that this program is used to create smaller projects that address planning criteria violations, with cost estimates based on smaller projects completed in the past. He noted that a follow-up to the company's discovery response indicated that the projects identified in Schedule M5 of Exhibit A-23 are actual projects.[559] Mr. Becker characterized this as a contradiction, also explaining that the discovery response confirms that the planning criteria violations have not been ranked. Mr. Becker concluded that the spending projections had not been adequately supported and recommended that the projected cost of $2.91 million be excluded from projected test year rate base.[560]

In rebuttal, Ms. Pfeuffer cited Exhibit A-23, Schedule M5, pages 140-143, testifying that they are actual projects identified for 2023.[561] She testified that the

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[558] 4 Tr 317-318.
[559] 8 Tr 5414-5415.
[560] 8 Tr 5415.
[561] 4 Tr 435-436.

revised discovery response in Schedule FF5 of Exhibit A-41 was “the final and correct response that meant to correct the record.”[562]

In its brief, DTE relies on Ms. Pfeuffer’s rebuttal testimony and the pages of Schedule M5 she cites.[563] DTE reiterates this in its reply brief, contending Staff ignored Ms. Pfeuffer’s rebuttal testimony and exhibit.[564]

In its brief, Staff urges the Commission to exclude the projected costs for this line item as recommended by Mr. Becker. Staff expressly addresses Ms. Pfeuffer’s rebuttal. Staff emphasizes the company’s use of the descriptor “a blanket” in explaining this project in Schedule M5, quotes the company’s discovery response in Exhibit S-15.3, page 5, which characterized the cost estimate as based on the past projects listed, and describes deficiencies and inconsistencies in the company’s subsequent discovery response.[565]

Ms. Pfeuffer did not address this line item explicitly in her direct testimony. Exhibit A-23, Schedule M5, page 140 states for this line item: “This category includes small projects aimed at addressing thermal overloads and voltage violations on the Subtransmission system.” At page 141, it further states: “This category represents a blanket to address small and localized overload conditions and voltage violations on the Subtransmission system. . . Individual project scope will be small, such as upgrade a relay panel, reconductor approximately 0.2 miles of overhead conductor, replace approximately 0.1 miles of cable, replace trainers, etc.” The document goes on to list “[s]ome examples identified for this program,” followed by four bullet-pointed projects.

[562] 4 Tr 436.
[563] DTE brief, 68.
[564] DTE reply, 45
[565] Staff brief, 34-36.

On page 143, the document identifies “blanket funding” as the “budget basis.” It also states that estimate project spend in 2021-2023 is $3.5 million. A review of the line item 36 on page 9 of Schedule B5.4 shows the entire $3.5 million assigned to 2023. Turning to the discovery responses cited by Mr. Becker, when asked for specific projects to support the $3.5 million expenditure, the company did state:

> The estimate was built based upon a combination of smaller projects that were completed in the past and many of which are likely going to be needed again, coupled with a preliminary idea of what projects could be needed from our last Annual System Review. Included in the project details are specific examples of past projects that would be part of this category, including the associated customer and system benefits.[566]

In response to a subsequent discovery request, STDE-25.16, Ms. Pfeuffer provided a list of six projects, only 2 of which are included on the list of 4 projects in Schedule M5 of Exhibit A-23 at pages 140-143. Costs are not provided for any of these projects.[567] Although Ms. Pfeuffer’s testimony is generally well-organized and thorough, her rebuttal testimony on this point is inaccurate. She testified:

> As stated in discovery STDE-25.16 and Exhibit A23 Schedule M5 pages 140-143 there are actual projects for 2023 calendar year. The Company has demonstrated the need for these projects and provided the detailed scope.[568]

She then lists 4 of the 6 projects listed in the discovery response she cites, only 2 of which are included in Schedule M5 at the referenced pages. As noted above, Schedule M5 at the cited pages does not state that the company has actual projects planned for 2023, and the company’s discovery responses have clearly been inconsistent about what is a planned project and what is a past project.

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[566] Exhibit S-15.3, page 5.
[567] Exhibit S-15.3, pages 11-12.
[568] 4 Tr 435.

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

iii. Pilot: Strategic service and undergrounding (B5.4, page 10, line 87)

As shown on line 87 of Schedule B5.4, page 10, DTE is projecting 2022 bridge-period expenditures of $17 million and test year expenditures of $40 million for strategic undergrounding pilots. Ms. Pfeuffer described strategic undergrounding as the practice of replacing overhead infrastructure with underground infrastructure: "The 'strategic' refers to strategically selecting areas of the electrical system to move from overhead to underground."[569] She testified that DTE has 30% of its lines underground, and explained the purpose of the Appoline pilot the company initiated in 2018:

> The primary purpose was to start developing cost effective and customer engaging process and method for replacing overhead infrastructure with underground infrastructure. Determining the costs of this work and understanding the opportunities to reduce these costs were a central focus.[570]

She further described the scope of the pilot, to install a looped underground residential distribution (URD) system to serve about 60 residences on two blocks in the City of Detroit. Noting that the pilot is within a circuit that will be converted to 13.2kV in the future, she stated "the pilot is being constructed to the higher voltage standard, in a way that will allow for a cost-efficient future conversion."[571] She testified that the loop has been completed and approximately half the customers have been transferred to it, and described two major challenges to completing the project:

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[569] 4 Tr 336.
[570] 4 Tr 337.
[571] 4 Tr 337.

> The first was the need to remove a significant amount of vegetation and garbage from what are now alleys owned by the customers before construction could start. The second is getting required customer approvals for work needed on their property. Currently, the Company is going door to door to meet with the customers to obtain the needed approvals to complete the project. The pilot has provided an understanding of the challenges with this work, and the lessons learned provide the background for improving on the processes and methods to reduce costs and increase customer engagement.[572]

She then explained DTE's plans to expand the project, citing "reliability data from 2019 to September 2021 [showing] that customers served by underground infrastructure have 34% to 52% better All-Weather SAIDI than customers served by overhead."[573] She also cited testimony DTE provided in Case No. U-17767 describing the restoration challenge posed by overhead services, and described reliability benefits to customers.[574] She testified:

> With the lessons learned from the Appoline pilot and benchmarking work, further pilots are being planned to improve customer engagement approaches, implement more cost-effective methods, and enhance processes with the purpose of scaling up Strategic Undergrounding in areas where it is needed.[575]

Acknowledging a need to balance reliability and cost as well as other factors, she testified that DTE "is developing overall life cycle cost models to compare and inform overhead versus underground decision making," and asserted that the pilots will help with this analysis.[576] She testified:

> In addition to completing the Appoline pilot, the Company is developing a balanced set of pilots with two approaches to undergrounding assets.
>
> • Replacing overhead services with underground services; and

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[572] 4 Tr 338.
[573] 4 Tr 339.
[574] 4 Tr 341-342.
[575] 4 Tr 339.
[576] 4 Tr 340.

• Replacing both overhead laterals and services with URD.[577]

Ms. Pfeuffer described one of the planned pilots further, indicating it would move overhead rear-lot assets to a front-lot URD for a circuit with high outages and higher-than-average downed wires, notwithstanding that tree trimming has been completed on the circuit.[578] She identified the primary change to the plan from the DGP description to be an increase in the number of services that will be replaced.[579]

Mr. D. Smith testified on behalf of Local 223 in support of the pilot.[580] He explained record keeping for workplace injuries and fatalities to show that incidents involving overhead power lines are significantly more numerous than those limited instances involving underground power lines.

As noted above, several witnesses objected to the company's proposal. Mr. Evans explained Staff's recommendation that the new pilots should not be funded until the Appoline pilot is completed and the results known and analyzed:

> Undergrounding 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.[581]

Quoting from a DTE blog, he noted that DTE is well aware of the relative cost of overhead and underground construction. He acknowledged the Commission's request for additional information on the cost of moving overhead lines to underground in its

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577 4 Tr 341.
578 4 Tr 342-343.
579 4 Tr 343.
580 8 Tr 3119-3121.
581 8 Tr 5431.

August 25, 2021 order in Case No. U-21122, but urged that "a cautious approach [is] still the reasonable and prudent approach."[582]

Mr. Ozar also recommended that the Commission not approve spending for the planned pilots, characterizing them as "astronomically expensive," equating the level of projected spending to the 4.8kV hardening program:

> The requested level of bridge and test year spend on these pilots has not been demonstrated to be in the public interest. The core associated learnings asserted by DTE Electric relate to ascertaining costs and benefits. Such learnings, although germane, are not commensurate with the proposed costs of the pilots.[583]

He considered it unlikely that undergrounding will prove to be cost effective, citing the $3 million cost per mile of the Appoline pilot.[584] He also objected to the premature replacement of distribution system laterals, based on the general principles he articulated, as discussed above:

> In addition, the Company asserts that the strategic undergrounding of laterals proposed in the pilot, despite it not being as cost effective as undergrounding of services, will prepare such areas for future voltage conversion. The Company has not provided any rational basis for premature replacement of existing distribution assets in anticipation of future conversions. The fact that the Company has not done circuit-level load-analysis for future transportation and building electrification (also a defect in establishing the appropriate timing of circuit conversions), exacerbates the unreasonable basis of voltage conversion as support for undergrounding.[585]

And he objected to the premature replacement of overhead service lines:

> An additional issue is that the proposed new pilot's goal of "proactive" replacement of overhead services runs afoul of the principle of replacement upon failure or replacement upon imminent failure. Overhead service line "challenges" (i.e., susceptibility to storm related damages) do

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[582] 8 Tr 5432.
[583] 8 Tr 4017.
[584] 8 Tr 4017.
[585] 8 Tr 4017-4018.

> not fall into the category of replacement upon failure or replacement upon imminent failure. The stated goal of addressing overhead service line challenges is a clear example of potentially costly capital spending brought about by early retirement of distribution assets in pursuant of unproven reliability gains.[586]

Noting that DTE cited customer interest in underground services as a motivating factor, Mr. Ozar cited R 460.516 to show that customers already have the right to obtain underground service at what he considers a fair cost, characterizing the company's plans to replace these lines with underground lines as an apparent workaround to this rule.[587] In lieu of pursuing the new pilots, Mr. Ozar recommended that the company be required to first finish the ongoing pilot, and conduct further analyses, including a lifecycle cost analysis of undergrounding, as discussed in more detail below.[588] He also had alternative suggestions to address customer concerns.

The strategic underground piloting was also one of the four projects Mr. Coppola identified in conjunction with his recommended 20% reduction in projected distribution system expenditures.[589] Citing Exhibit AG-1.7, he reviewed the pilot expenditures to date, testifying that it is evidence the company experienced significant issues and higher costs, and "did not obtain pre-approval from customers before proceeding with the pilot project and did not adequately scope the work required to complete the project. The Company considers these difficulties as lessons learned."[590] Mr. Coppola found it unclear what additional lessons will be learned from an additional pilot project, and

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[586] 8 Tr 4019.
[587] 8 Tr 4018.
[588] 8 Tr 4020-4022.
[589] 8 Tr 4761-4764.
[590] 8 Tr 4762-4763.

recommended that the proposed spending be disallowed or subsumed within his general reduction:

> In either case, the Commission should instruct the Company to better define what specific information it desires to gather from additional pilot projects and also improve their design, scope, and execution to achieve maximum effectiveness. The Commission should make it clear that recovery of costs pertaining the undergrounding pilots will be critically evaluated in the Company's next rate case.[591]

In rebuttal, Ms. Pfeuffer testified that she considers the Appoline pilot to be complete "for all intends and purposes,"[592] with 20 out of the 61 homes involved remaining to be connected:

> Of the 20 remaining homes, 17 of them are renters who are not authorized to approve the changes needed for undergrounding work. The Company has established connections with the local government to identify the homeowners for the remaining rental homes. With this information, the Company has been contacting the homeowners to obtain the required customer agreements. The remaining house service conversions are scheduled to be completed before the end of the year.[593]

She contended:

> The Company has gained the key learnings from Appoline to apply to future Strategic Undergrounding work. All of the distribution primary and secondary have been converted to underground in the two-block area. There is no reason to wait to bring the important safety and reliability benefits to the Company's customers, and DTE Electric is well underway with scoping the work, engaging service providers, planning for customer engagement, and discussing the work with the City of Detroit.[594]

She considered that the two key learnings from the Appoline pilot are that the company should get customer signoffs before starting construction, and that construction will be

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[591] 8 Tr 4764.
[592] 4 Tr 438.
[593] 4 Tr 438.
[594] 4 Tr 438.

more efficient on a larger-scale project than for a small project such as the Appoline project:

> As described in the 2021 Storm Report MSPC Case No. U-21122 on page 31 section A, the Company expects the cost to be reduced by between 20% and 30%, which is what the Company has experienced on similar programs that went from pilots to full implementation.[595]

She further explained:

> [T]o reduce costs, it is imperative that the Company increase the volume of work completed significantly. This is the only way to develop the workforce, improve equipment utilization, reduce mobilization costs and achieve other economies of scale aspects.[596]

Ms. Pfeuffer also emphasized other factors that should be considered in addition to cost, including safety and reliability. She stated that the company views this program as a "well-suited option for circuits that consistently experience outages and down wires, despite regular maintenance including tree trim," and considers the proposed Fairmont pilot as an example. She testified that the company is prepared to complete these pilots:

> [T]he Company has been preparing to do these pilots for some time and has engaged the communities in which the pilots will occur, preparing to receive long lead time material, the engineering is complete for the Fairmount pilot and the specific locations for the 2022 services have been identified, contractors have been engaged to perform the work, and schedules have been developed.[597]

Specifically responding to Mr. Coppola, she disputed that the company would use the same process in future pilots, testifying that company's Fairmont pilot will move rear-lot overhead laterals to front-lot URD, and will use the lessons learned from the first pilot, benchmarking, increased efforts at community engagement, and city support.[598]

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[595] 4 Tr 439.
[596] 4 Tr 440.
[597] 4 Tr 442.
[598] 4 Tr 444-445.

She testified that benchmarking has established that focusing on undergrounding efforts on front lots offers the best option for reliability and aesthetics. Citing pages 349-351 of Schedule M1, the DGP, Ms. Pfeuffer reiterated that the company wants to assess the impact undergrounding has on restoration times, and will conduct a pilot focused on undergrounding services only:

> Per Exhibit A-23, Schedule M1, page 349, "overhead residential services are approximately 16 times more likely to fail during storms than underground residential services," which makes putting focus strictly on undergrounding services a worthwhile pilot project on its own. [599]

Ms. Pfeuffer also disputed Mr. Coppola's conclusion that the company has not identified lessons learned from the Appoline pilot, also discussing lessons learned from benchmarking as presented in the DGP, Schedule M1 of Exhibit A-23.[600]

Specifically responding to Mr. Ozar's testimony, she agreed on the importance of benchmarking, testifying that the company has "completed benchmarking work" and "plans to continue it" for this program.[601] She also agreed on the importance of lifecycle analysis, asserting that it "can only be informative when supported by the actual experience that the Company will gain from the Strategic Undergrounding pilots."[602] She reiterated her view that the Appoline pilot is complete "for all intents and purposes," with minimal remaining lessons to be learned, also stating that the company has learned a great deal from that pilot.[603] She also reiterated her expectation that the cost of the work will be reduced by increasing the volume and utilizing lessons learned from the Appoline pilot and benchmarking work.

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[599] 4 Tr 445.
[600] 4 Tr 446-447.
[601] 4 Tr 449.
[602] 4 Tr 449.
[603] 4 Tr 449.

In its brief, DTE discusses the potential effects of climate change, citing its DGP, as a motivation for the pilots. DTE relies on Ms. Pfeuffer's direct and rebuttal testimony. DTE disputes that the potential for undergrounding is limited, contends it will obtain a cost advantage from larger scale, and further contends that the focus of one of the new pilots on moving from rear-lot overhead to front-lot underground will reflect "a major difference in scope and approach," and that the company will undertake "a greater level of effort and proactiveness for customer engagement in the proposed pilots" than in the first one.[604] It also argues that there are other important considerations in addition to cost, citing Local 223's support for the project. In its reply brief, DTE reiterates these arguments, and cites the Commission' s August 25, 2021 order in Case No. U-21122 asking utilities to consider undergrounding.[605] It argues that the pilots it proposes here "will allow the Company to fully answer the Commission's inquiry."[606] Consistent with Mr. D. Smith's testimony, Local 223 urges the Commission to approve the pilots.[607]

The Attorney General relies on Mr. Coppola's testimony, and addresses Ms. Pfeuffer's rebuttal testimony by arguing that the additional learnings she cited are "basic" and "unhelpful" and do not justify this pilot:

> The Company has sufficient experience with undergrounding electric lines in other locations of its service area to know what it takes to trench bore, reach new meters, extend cable, repair driveways and landscaping, and engage with customers.[608]

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[604] DTE brief, 70.
[605] DTE reply, 46-50.
[606] DTE reply, 49.
[607] Local 223 brief, 2-3.
[608] Attorney General brief, 51.

The Attorney General also asks the Commission to instruct DTE to better define the specific information it desires from additional pilots, and improve their design, scope and execution.[609]

Staff argues that expenditures for new undergrounding pilots should not be approved until the Appoline pilot is completed and the results known and analyzed, stating that completing the pilots one at a time is the prudent course of action.[610] Staff also disputes Ms. Pfeuffer's explanation of the learnings from the incomplete Appoline pilot, including the importance of acquiring customer signoffs before construction starts, and her prediction that work on a larger scale will lead to efficiencies:

> This learning is not a substantive pilot result, and the prediction is not a result at all. The need to acquire customer agreement signoffs before starting work on customers' property could easily have been assumed in advance. The prediction that undergrounding on a larger scale will lead to efficiencies may be a reasonable prediction, but it is not an actual result of this pilot, just a rationale for more pilots.[611]

Staff considers the 20%-30% cost savings for underground construction that Ms. Pfeuffer "expected" from "scaled up" work to be small compared to the overall cost of the undertaking, and also noting the company's failure to evaluate alternatives.[612]

MNSC cites Mr. Ozar's testimony, noting his characterization of this as a "proactive" replacement rather than replacement on failure or imminent failure. MNSC addresses Ms. Pfeuffer's rebuttal testimony, contending it does not respond to Mr. Ozar's concerns, noting the company has not undertaken a lifecycle cost assessment

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[609] Attorney General brief, 50-51.
[610] Staff brief, 41-42.
[611] Staff brief, 43-44.
[612] Staff brief, 44-45.

as recommended by Mr. Ozar, and further characterizing the company's expected cost reductions as "circular reasoning." MNSC argues:

> It is premature in this proceeding to support the cost-effectiveness of the pilot by relying on cost savings that may be achieved when this pilot is subsequently rolled out more widely. The issue is whether this pilot is cost effective and whether the lessons expected to be learned are worth the very high cost. Concluding that the later roll-out of the pilot may be more cost effective (more efficient) than the pilot is circular and evasive.[613]

MNSC cites additional information in Exhibits MEC-102 and MEC-103, and further objects:

> The Company failed to address Mr. Ozar's testimony regarding Rule 460.56, the Company's tendency towards proactive rather than preemptive replacements, the evidence that on a life-cycle basis undergrounding is not cost-effective. The Company also failed to address Mr. Ozar's recommendations for additional scope of assessment, alternative funding sources, revised programs to address the root cause of outages (enhanced trimming along secondary lines). For these reasons and those addressed by Mr. Ozar in his testimony, the Commission should reject the Company's proposed spending proposal and instead adopt Mr. Ozar's recommendations and with $1 million to that end.[614]

MNSC addresses Local 223's concerns by concurring that safety concerns should be part of a comprehensive cost/benefit analysis that evaluates undergrounding on a lifecycle basis, to be evaluated in a future rate case.

In its reply brief, DTE essentially reiterates Ms. Pfeuffer's rebuttal testimony.[615] It adds that Exhibit AG-1.64 supports the company's pilot. It responds to MNSC's brief specifically by arguing 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

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[613] MNSC brief, 143-144.
[614] MNSC brief, 144.
[615] DTE reply, 46-50.

actual experience that the Company will gain from the Strategic Undergrounding pilots," citing Ms. Pfeuffer's rebuttal testimony at 4 Tr 449.[616]

This PFD finds that the spending for continuation of this program should be rejected at this time, for the reasons articulated by Mr. Becker, Mr. Ozar, and Mr. Coppola. The initial pilot for which approval was granted has not in fact been completed, and the Commission and the parties should have the benefit of a full report on the costs of the pilot, including the costs of obtaining customer consent and dealing with unanticipated construction obstacles, prior to approving additional funding. As the parties note, the company is proposing to spend an additional approximately $60 million on these projects in 2022 and 2023. Moreover, it appears that the company is now considering this at least akin to a permanent program, which is premature for the reasons articulated by Staff, the Attorney General, and MNSC.

Although Ms. Pfeiffer identified two lessons learned from the pilot, it appears that the company has learned one expensive lesson from this pilot: it should have obtained approval of the homeowners prior to beginning construction. Regarding the potential cost efficiencies of larger-scale operations, it is unclear how the company bases its views on the experiences from this pilot, rather than on a general experience with construction. These are not sufficient learnings to justify an expansion of this program. Instead of presenting a full evaluation of the pilot, DTE is essentially asking the Commission to see only the potential benefits of the program, and not the cost or the cost of alternative approaches to achieving similar benefits. As Mr. Ozar explained at length, the company has not provided a lifecycle analysis of the benefits of

[616] DTE reply, 49.

undergrounding, noting expenses associated with maintaining that system as well, relative to the cost of conversion.

If the company's plans are as complete as it claims, it will not hurt to pause the complete package while Staff, other interested parties, and the Commission have the opportunity to review actual analyses from the first pilot.

Considering that DTE has acknowledged that notwithstanding what it claims as its benchmarking efforts prior to undertaking this pilot, it neglected to obtain homeowner permission before embarking on the first pilot, it is difficult to understand why it does not want to present a full analysis of its experiences to the Commission before proceeding with additional work. This PFD notes that DTE has not provided a final cost estimate for that pilot, or explained why it believes that pilot will be completed anytime soon. The company did not make any attempt to quantify the costs and benefits of its pilot. This PFD concludes that DTE has not established that its proposed pilots are reasonable and prudent, or that it has a credible cost estimate or timeline for the work it proposes to undertake.

f. Technology and automation (B5.4, page 1, line 21; B5.4, page 11)

As shown in on page 11 of Schedule B5.4, DTE's filing reported 2021 capital expenditures of $73 million for this third category of strategic capital expenditures, with approximately $100 million projected for the ten-month bridge period and $137 million for the test year. Schedule B5.4, page 11, has expenditures broken down into 39 line items, most of which are the subject of some dispute. Ms. Pfeuffer explained that "[i]nvestments in technology and automation are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications."[617] In addition to Ms. Pfeuffer, Ms. Elliott Andahazy and Mr. P. Smith testified in support of the company's historic and projected capital expenditures in the third category of strategic capital. Additional details are in Schedule M6 of Exhibit A-23.[618]

Staff witnesses Dr. Wang, Mr. Evans, and Ms. Rogers testified regarding this category. Dr. Wang explained several general objections Staff has to many of the company's projections without regard to the reasonableness and prudence of the underlying projects; Staff also has specific objections to certain projects. Staff's Exhibit S-7.42 has a line-by-line summary of Staff's recommended adjustments to the company's projections. Staff's general objections are reviewed in subsection i below. Three of the four projects that Mr. Coppola included within his list of projects that partially encompass his 20% recommended disallowance for distribution strategic capital spending generally are in the technology and automation category and are discussed below. As the following discussion shows, DTE's expense projections in this case reflect significant cost overruns for multiple projects, in comparison to the projections DTE provided when the projects were originally approved, including DTE's ADMS project, now on two separate lines, and its System Operations Center, which is now also on two separate lines. These are discussed in subsections ii through iv below.

i. Staff general adjustments

Dr. Wang also raised a concern with the company's underspending in this subcategory of strategic capital spending. She compared an estimate of the company's

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[617] 4 Tr 347.
[618] Pfeuffer, 4 Tr 386-387.

projected 2020 spending in Case No. U-20561 to the 2020 actual spending reported in Schedule B5.4, for "projects with the same name or projects that were discernable in terms of project name changes and known to Staff at the time of the analysis."[619] She explained the results:

> Staff found variation in the alignment of the Company's actual spending with the projected amounts. The percent of projected capital costs that were actually spent in 2020 varied from 0.36% to 133.8%, with an average of 73.3% of projected costs actually spent.[620]

She testified for the specific projects analyzed, Staff recommends a reduction in projected expenditures commensurate with the company's recent level of underspending on projects in this category. For other projects for which Staff has no objection to the scope of the project, Staff recommends a reduction of 20%. In its brief, Staff makes clear that it considers this analysis an estimate of the company's forecast accuracy.

Dr. Wang explained that Staff also has concerns regarding the company's capitalization of certain expenses within this category. She cited Financial Accounting Standards Board guideline ASC 350-40:

> FASB ASC 350-40 classifies three stages of computer software development: Preliminary Project Stage, Application Development Stage, and Post-Implementation/Operation Stage. In the Preliminary Project Stage, the reporting entity determines the project scope, explores alternatives, determines technology needed, and selects vendors and consultants. In the Application Development Stage, the reporting entity designs the chosen path, such as software configuration and interfaces, conducts coding, installs hardware, and tests for initial verification of application functionality. In the Post-Implementation Operation Stage, the reporting entity conducts training and application maintenance.[621]

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[619] 8 Tr 5224.
[620] 8 Tr 5224.
[621] 8 Tr 5189.

She explained that Staff is concerned that the company is capitalizing the “preliminary project stage” expenses within certain line items.[622] This concern plays a role, as discussed below, in Staff’s recommendations for those line items.

Consistent with Staff’s objections to certain IT capital expense projections discussed below, Staff objected to the projections for certain line items based on the company’s projection method that Staff refers to as “t-shirt sizing.” Ms. Wang testified:

> The High-Level T-Shirt Sizing Cost Estimation process is a standardized estimation model developed by the Company. It is used as the basis for high level IT estimates of project cost. There appear to be only two criteria featured in determining the project cost range. These are project size or complexity (S – XXXL) and duration in months. The Company primarily considers project complexity, duration, and benchmarking in IT project cost estimates.[623]

Dr. Wang considered that projections made on this basis were insufficiently reliable to include in rate base and recommended that the projected costs be excluded. Staff’s adjustments to lines 24, 26, 27, 29, and 34 resulted in a total reduction in bridge period expenditures of $9.73 million and a total reduction in test year expenditures of $16.06 million.[624]

Dr. Wang also considered the other line-item projections in this category to be “high level” estimates rather than detailed, and recommended 20% reductions in those line items for which Staff did not recommend a project-specific adjustment:

> For Technology and Automation projects that do not have a capital disallowance based on scope for the projected bridge period or test year, Staff recommends a 20% capital disallowance for high-level costs. With high-level cost projections, there is significant uncertainty that the projected costs will actually materialize as predicted. This yields a

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[622] 8 Tr 5191-5196.
[623] 8 Tr 5187.
[624] 8 Tr 5188.

> recommended capital disallowance of $3,623,000 in the projected bridge period and $4,258,200 in the projected test year across eleven projects.[625]

She also equated the 20% reduction to the company's 2020 level of underspending based on the analysis described above.[626]

The last of Staff's general concerns with the company's expense projections in this category related to loadings for non-labor, non-material costs in the "other cost" category of the company's cost breakdowns. Dr. Wang testified that this category includes administrative and general costs and other overhead, and she explained:

> The Company does not have a 'baseline' amount it assumes for Other Costs. It says Other Costs are based on project cost estimates or historic values for similar projects. Project specific details impact the amount of accounting allocations.
>
> Though the Company has not done any variance analysis around Other Costs, Staff examined the variance of Other Costs as a percentage of total project costs for the projected test year, finding percentages vary from 5.17% - 18.12%. However, there is no explanation from the Company regarding the Other Cost variation of cost estimates.[627]

She recommended that the amount of "other costs" be limited to 5.17% as the low end of the range, noting that the company could recover additional "other costs" if it can substantiate them once actual expenditures are known. She also recommended that the company provide clarity on these cost projections in future cases.[628]

Ms. Pfeuffer contended that none of Staff's general concerns should form the basis of reductions to the company's expense projections. She considered the

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[625] 8 Tr 5220.
[626] 8 Tr 5221.
[627] 8 Tr 5212-5222.
[628] 8 Tr 5223.

magnitude of Staff's disallowances in total to show that Dr. Wang disagrees with the importance of technology and automation.[629]

Similar to her testimony regarding Mr. Becker's recognition of historic underspending on strategic capital, Ms. Pfeuffer objected to the use of an average of underspending amounts, which in this case were project by project.[630] She objected that Dr. Wang estimated the 2020 projections based on the company's bridge and test-year projections, asserting that specific 2020 projections were available in the record for Case No. U-20561;[631] she objected that all projects were not included in the analysis;[632] and she considered the average flawed, presenting an Schedule FF8 of Exhibit A-41 to show the alternative calculation of a 137% average.[633] Ms. Pfeuffer also objected to Staff's use of the specific underspending percentages for certain projects and Staff's reliance on the overall average for other projections, characterizing this as inconsistent.[634]

In explaining her objection to Staff's reductions based on the high-level nature of the company's estimates, Ms. Pfeuffer considered it "not reasonable or prudent to propose disallowance of an entire group of projects solely because of a concern about an estimating method." She cited Schedule FF11 of Exhibit A-41 to further explain the "t-shirt-sizing" estimates, explaining that they are "just the initial planning estimates that remain in place in until the program is ready to start," at which point, "[t]he project planned would then proceed through the IT APC Process" described by Mr. Sharma at

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[629] 4 Tr 450.
[630] 4 Tr 454-460
[631] 4 Tr 455, 456-457.
[632] 4 Tr 457-458.
[633] 4 Tr 458-459.
[634] 4 Tr 459-460.

7 Tr 1928.[635] She disagreed with Dr. Wang's view that there is little consideration for project scope, goals, and desired outcomes in the high-level t-shirt cost estimation process.[636] In the cited portion of his testimony, Mr. Sharma explained "how a project moves from prioritization to final approval" in the company's IT Annual Planning Cycle (APC) process, describing estimation levels 1, 2, and 3.[637]

Ms. Pfeuffer also addressed Staff's concern with the "other cost" category of the company's expense projections. She testified that these cost allocations "are based on multiple factors including amount of labor and material used and project duration," and that the "other cost" as a percentage of project costs can vary "[a]s projects move through phases of material purchases to labor to install."[638] She cited the company's discovery response in Schedule FF9 of Exhibit A-41, and a Staff discovery response in Schedule FF10 of that exhibit, to show that Staff did not review information the company provided showing the actual breakdown of 2020 and 2021 costs.[639] Ms. Pfeuffer also objected that Staff had not provide any statistical analysis in support of the 5.17% estimate.[640]

Ms. Uzenski also provided rebuttal testimony on the issue of the "other" cost component of the company's projections.[641] She testified that the costs for overhead activities are collected in pools and allocated to capital projects, that facilities overhead costs, stock overhead costs, and procurement overhead costs are allocated using

[635] 4 Tr 464-465.
[636] 4 Tr 465.
[637] 7 Tr 1928; also see 7 Tr 2129.
[638] 4 Tr 462.
[639] 4 Tr 462-463.
[640] 4 Tr 463.
[641] 7 Tr 2785-2786.

different "drivers," and citing Schedule HH6 of Exhibit A-43 to show the list of overheads and a description of how they are allocated. She testified: "Since other overheads can vary depending on the type of project and the direct costs charged to the project, a fixed flat rate as recommended by Staff is unreasonable, and the Commission should reject Witness Wang's proposal to reduce "Other" capital costs."[642]

DTE's brief reiterates Ms. Pfeuffer's and Ms. Uzenksi's general objections to Staff's approach to this category at page 73-76 of its brief, before discussing specific line items. Regarding Staff's analysis of historic underspending, DTE argues that Staff ignored the company's actual 2020 forecast from Case No. U-20561 in constructing an estimated calendar year forecast from the bridge and test year projections in that case. DTE also argues that Staff should have considered the average overprojection of 137% looking at all projects except for the SOC project, as shown in Schedule FF8 of Exhibit A-43.[643] Regarding the t-shirt-sizing estimation issues, DTE cites Ms. Pfeuffer's and Mr. Sharma's rebuttal testimony and Schedule FF11 of Exhibit A-43 in arguing that "it is not reasonable or prudent to propose disallowing an entire group of projects based solely on a concern about a cost-estimating model."[644] Regarding "other" or overhead costs, DTE relies on Ms. Pfeuffer's and Ms. Uzenski's testimony described above, arguing it provided additional information in Schedule FF9 on its cost allocations in Schedule FF9 but Staff did not review this information as shown by Schedule F10 of Exhibit A-43.[645]

In response to Ms. Pfeuffer's rebuttal testimony, Staff acknowledged that DTE had presented projections specific to calendar year 2020 in Case No. U-20561, and

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[642] 7 Tr 2786.
[643] DTE brief, 73-75.
[644] DTE brief, 76.
[645] DTE brief, 75-76.

revised its historical-underspending-based adjustments for the related projects to reflect these specific projections.[646] Staff otherwise stands by the general adjustments Dr. Wang recommended for this category. In its reply brief, Staff also addressed DTE's defense of its "other" cost projections, arguing that the company fails to explain how these costs were allocated in detail, disputing that Schedule FF9 of Exhibit A-41 sheds light on the basis for the company's projection of "other" costs.[647]

After reviewing the "detail" underlying the company's cost projections in Schedule M6 of Exhibit A-23, this PFD finds that DTE's cost projections for this category lack credibility. As Dr. Wang testified, DTE regularly identifies "engineering estimate" as the basis for most of the cost projections, but the engineering estimates are actually "high level" estimates. As DTE stated in Exhibit S-15, page 2: "project management, engineering estimate, high-level IT estimate, and IT estimate" are *used interchangeably*. Although Dr. Wang's adjustments distinguished between "engineering estimates" and the other labels DTE used, only treating the "high-level IT estimate and "IT estimate" descriptors as reliant on the t-shirt sizing estimation method DTE illustrated on page 2 of Exhibit S-14 page 2, this PFD concludes that the company's discovery responses in Exhibit S-14 page 1 and Exhibit S-15, page 2, indicate that DTE used the t-shirt sizing method for additional projections in this category. Because DTE did not establish the actual basis on which any of the disputed projections were made, the record supports the characterization of all of the expense projections as "t-shirt sizing estimates."

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[646] Staff brief, 84-88.
[647] Staff reply, 12-13.

Schedule M6 does not provide any comparable cost detail for 2021 spending, and it does not provide total project cost, or O&M costs. Considering the IT relationship embedded in this cost category, it is particularly troubling that DTE did not provide the information the Commission has called for regarding IT projects, which is discussed in more detail below but requires detail missing from Schedule M6. On this basis, the company's response regarding the capitalization or expensing of these costs is also not persuasive. The company did not establish any O&M expense projection for these line items. And its contention that none of the projects are in a preliminary phase is not credible given the project descriptions. Dr. Wang cited the automation configuration and test record data base as an example, referencing Schedule M6 extensively, including the project descriptor that included "data preparation and conversion," and "evaluating software options."[648] DTE did not present any project timelines associated with its expenditures, and did not present O&M expenses incurred to date, so its vague assertions that it has passed the preliminary project phase and that its accounting will be correct are not persuasive. DTE had complete control over the information it chose to present in support of its projected expenses.

Turning to Staff's "other" adjustment, this PFD finds Staff's adjustment is reasonable. In this context, it is worth noting that DTE filed revised versions of Schedules M4 through M6 on April 5, 2022. As shown by the revisions, DTE's initial filing included the exact same cost allocation on all pages: 75% labor, 15% materials, and 10% other. DTE did not explain its revised filing other than to state in the cover letter that the revision was "limited to correcting the breakdown between

[648] 8 Tr 5190-5193.

material/labor/other for projects." The projections in Schedule M6 are intended to account for over $236 million in 10-month bridge and test year expense projections. Not only does DTE fail to explain the basis for its current "other" cost calculations, it has not explained how it filed its case with flat rates, while now contending that would be unreasonable. Looking at the list of cost elements DTE claims to include in the "other" category, certain of these elements resemble contingency is that it is highly uncertain that they can be projected with accuracy. For example, DTE includes AFUDC—presumably projecting that projects will be completed and that it will be able to recoup CWIP offsets. In addition to the highly speculative nature of such assumptions, it must create an auditing obstacle in rate cases with statutorily limited timeframes. This PFD notes that DTE's treatment of AFUDC has been an issue in prior cases.

For these reasons, this PFD concludes that Staff's adjustments are a reasonable means of addressing the evidentiary deficiencies in the company's presentation, and should generally be adopted. Staff's historical spending adjustments will be discussed in the context of the individual line items.

ii. ADMS: DMS/OMS (B5.4, page 11, line 2)

DTE reports 2020 spending of $19.4 million for 2020 and projects spending of $34.1 million for the 22-month bridge period and $50.4 million for the test year for this portion of its Advanced Distribution Management System (ADMS) project. Ms. Elliott Andahazy explained that ADMS includes hardware and software to "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."[649] Citing Mr. Bruzzano's testimony in Case No. U-20561, she testified that ADMS is the umbrella name for 3 projects with 5 components: generation management system (GMS) and energy management system (EMS); outage management system (OMS) and distribution management system (DMS); and network management system (NMS). She described the five components at 7 Tr 1490-1491. She testified that projected expenditures for the ADMS project were approved in Case Nos. U-20162 and U-20561. In Case No. U-20561, she explained, $58.1 million in costs through the projected test year were included in rate base, while total costs for the project were projected to be $64.7 million.[650] After addressing customer benefits from ADMS, including projected all-weather SAIDI reductions,[651] she reviewed the steps the company took to implement the program beginning in 2015, the selection of vendor OSI, and the original schedule for implementation.[652] She testified that the GMS component was completed in 2018, EMS was completed in 2019, and NMS was completed in 2020.[653]

Ms. Elliott Andahazy described the DMS component as follows:

> Distribution Management System (DMS): provides a complete network model of the electrical system for operators to view system conditions in real time. DMS consists of multiple applications such as Network Model (eMap), Distribution Power Flow (DPF), Distribution State Estimation (DSE), and applications with more advanced functionality such as Fault Location, Isolation, and Service Restoration (FLISR), Volt/Var Control (VVC), Conservation Voltage Reduction (CVR), Feeder Reconfiguration (FR) and electronic Switch Order Management (SOM). DMS allows the Company to gain and access advanced situational awareness of the

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[649] 7 Tr 1490.
[650] 7 Tr 1492.
[651] 7 Tr 1492-1495.
[652] 7 Tr 1495-1498.
[653] 7 Tr 1498.

distribution system from the Transmission Interconnection to the customer's connection on the distribution system.[654]

She described OMS as follows:

> Outage Management System (OMS): aggregates emergent trouble information reported by customers and Advanced Metering Infrastructure (AMI) meters and allows system operators and dispatchers to prioritize response and properly assign crews for repairs. Emergent trouble is defined as storm and non-storm, outage and non-outage events reported in the system.[655]

She testified that although OMS was to be completed in 2020 and DMS in 2021, implementation of these components has been delayed:

> Most of the OMS and DMS are now scheduled for completion by the end of 2022, as discussed later in my testimony. In early 2020, DTE Electric hired an experienced System Integrator (Ernst & Young) to support the OMS/DMS project, which is industry standard practice when implementing an ADMS. The System Integrator helps the company with the overall delivery strategy, coordinates all testing efforts, coordinates integration between software packages (new and legacy software), and creates appropriate training materials for the organization. For the OMS and the DMS Network Model application, the team has completed system configuration, Factory Acceptance Testing (FAT), and Site Acceptance Testing (SAT). In addition, the Company has developed drafts of the associate training materials and conducted "Train the Trainer" sessions for the OMS. The project team is currently working through System Integration Testing (SIT), defect remediation and testing, and partnering with OSI on enhanced functionality (enhancements) to improve the base product and meet additional operational needs. This due diligence and system refinement before full deployment are absolutely necessary to ensure a successful roll out given the critical role of these systems to overall system reliability and safety. The training materials and training sessions will also be completed as defects and enhancements are remediated by OSI to support the rollout and implementation with accurate, easy-to-understand tools for all users. For the remaining DMS applications, the Company is in the process of system configuration and preparing for the upcoming testing cycles (FAT, SAT, and SIT).[656]

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[654] 7 Tr 1492.
[655] 7 Tr 1492.
[656] 7 Tr 1502-1503.

She attributed the delays to the mobile compass tool, noting an early delay to ensure compatibility with multiple field devices, and explaining further delays:

> Specifically, OSI delivered the first working Compass test environment in the second quarter of 2020, opposed to December 2019 as planned. Once the base product was delivered, the Company partnered with OSI to continue developing the additional functionality required to replace the Company's existing(legacy) mobile tool and to improve the functionality between the new Compass mobile tool and the base OMS product. Restrictions imposed during the COVI pandemic made the partnership and continued development of the Compass tool extremely challenging. For example, the OSI and DTE Electric project teams were not able to travel and meet in person until August 2021. Due to the complexity of the technology required to support the needed mobile functionality, and the increased complexity of partnering on a project of this magnitude given the restrictions in place due to the pandemic, the Company had to make the decision to move the implementation date of the DMS Network Model, OMS, and Compass mobile tool. The critical nature of these systems to the Company's daily operations informed this decision. Although some systems can be deployed and continued to be refined over time after they are live, it was determined that this system needed additional design improvements and testing in order to be ready for use in operations by the Company and avoid potentially costly workarounds and problems. As discussed in more detail later in my testimony, the new implementation date is the fourth quarter of 2022 to accommodate the time needed for OSI to remediate the issues and develop required enhancements.[657]

She testified that as a result of the delay, DTE will "leverage another field work force (field force) management software solution called ClickSoft, that is already a project included in the Company's strategic plan for OH/UG field resources."[658] She discussed the ClickSoft mobile component further, acknowledging "some overlapping functionality" with Compass, but contending "they are actually complimentary programs and both are needed to provide field personnel with a full field force management tool and a situational awareness tool to realize the full benefits of the ADMS."[659]

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[657] 7 Tr 1504
[658] 7 Tr 1507.
[659] 7 Tr 1510.

Because the Compass tool was delayed, the DMS implementation that was to follow the OMS implementation was also delayed.[660] She testified that with the exception of Compass and the "Switch Order Management" (SOM) component of DSM, DTE projects completion of OMS and DMS by the end of 2022:

> As stated earlier, the Company will roll out the Compass mobile tool as soon as OSI delivers agreed upon functionality, and it is fully integrated with the ClickSoft tool. Due to the complexity of change management needed to help frontline employees understand and embrace the new technology and associated processes, the SOM DMS application will be technically cut over in late 2022 with the other DMS components, but will be rolled out to the frontline employees for daily operational use in mid-2023. This delay in implementing SOM will allow employees the time needed to be fully trained and understand the change impact of the new SOM processes, and will allow future maturity in the Network Model for improved data quality and increased safety.[661]

Notwithstanding the prior delays, she asserted that DTE "took appropriate steps to mitigate these risks effectively" to ensure the delivery dates are not further delayed.

Ms. Elliott Andahazy testified that the OMS/DMS portion of the AMS project is now projected to cost $93.9 million, which includes historical costs along with the $83.5 million in 2022-2023 costs shown on line 2 of Schedule B5.4, page 11.[662] She broke the $29.2 million cost increase into four components:

> 1) $3.7 million of planned investment was not included in the Exhibit A-12 from MPSC case No. U-20561 due to the years in scope for that case; 2) there is an additional $5 million included for an expanded ADMS Reporting project, which was not included in the original scope; 3) there is an additional $6.9 million included for the emergent trouble portion of the ClickSoft project already planned in the Company's strategic investment that is being pulled up to correspond to the OMS cutover date; and 4) the remaining $13.6 million of additional costs are

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660 7 Tr 1504-1505.
661 7 Tr 1511-1512.
662 7 Tr 1513.

> associated with the ADMS: DMS/OMS project delays due to COVID and the delayed delivery of the Compass mobile tool.[663]

She also further addressed the reporting project mentioned in the second item above, explaining that it was not included in the original scope of the ADMS project.[664]

Staff initially recommended reductions to DTE's projections for this line item totaling $8.76 million for the bridge period and $2.16 million for the test year. As shown in Exhibits S-7.41 and S-7.42, Staff reduced the company's projections to reflect Staff's assessment that the company actually spent only 82.6% of its projected expenditures in 2020. As shown in Exhibits S-7.40 and S-7.42, Staff adjusted the loading for "other costs" to the 5.17% level explained by Dr. Wang. In its brief, Staff revised its historical adjustment to reflect that DTE actually spent only 69.3% of its projected amount, resulting in revised reductions of $11 million for the bridge period and $2.7 million for the test year.[665]

Mr. Coppola objected to the delays and cost overruns associated with this project, ascribing them primarily to the company's decision to proceed with implementation when OSI's OMS products were still new.[666] He quoted his testimony from Case No. U-20162 expressing this concern, and further explained:

> The Company now faces cost overruns [of] $17.5 million, excluding the Clicksoft cost portion, and seeks to recover those costs from customers. The Company blames Covid-19 for a portion of the time delay and cost overruns but could not provide an amount as to how much the Covid-19 restrictions may have impacted the time and cost of the project. The Company has also added $6.6 million of project costs for additional reporting features. The necessity and value of those reporting features

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[663] 7 Tr 1514.
[664] 7 Tr 1516-1517.
[665] Staff brief, 86.
[666] 8 Tr 4768-4769.

> added after the initial project scope have not been adequately supported and justified.
>
> In summary, the 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 recovery 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.[667]

While acknowledging it is premature to disallow costs for this project "until the project is completed and all the costs are known," he recommended that the Commission exclude forecast 10-month bridge period expenditures of $28.45 million and test year expenditures of $12.43 million from the projected rate base in this case, and thus "preserve its options if after review of the completed project a permanent cost disallowance is warranted."[668]

In rebuttal, Ms. Elliott Andahazy objected that Mr. Coppola did not "provide evidence that the ADMS investment does not provide value to the customers and the Company as described in the All-Weather SAIDI improvements, and additional benefits noted [at 7 Tr 1494-1495]," and did not "address that ADMS is the essential technology to support the modernized grid."[669] She also reiterated her contention that additional investment was required to replace existing systems that were reaching end-of-life, citing her direct testimony at 7 Tr 1495. She testified that DTE demonstrated in Case No. U-20162 that the ADMS projects would help address systems that have reached end-of-life, citing the PFD and Commission order in that docket.[670] She also defended the company's decision-making on the basis that it would not be reasonable or prudent

[667] 8 Tr 4769.
[668] 8 Tr 4770.
[669] 7 Tr 1540.
[670] 7 Tr 1542.

for the company to adopt only those new technologies that are fully developed in the industry, further citing the Commission's order in Case No. U-20162. She testified:

> When OSI had challenges to meet 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 use of this system by field personnel.[671]

She also objected to the amount of disallowance identified by Mr. Coppola, contending that the $40,879,000 disallowance he recommended is "substantially greater than the total increase of $29,200,000 the Company requested."[672] She further testified:

> It appears AG witness Coppola is trying to retroactively disallow capital that has been previously approved by the Commission because he doesn't agree with the investment, not because of the project delays and associated project investment increases as described.[673]

Responding to Staff's recommended reductions to the expense projections for this line item, Ms. Elliott Andahazy referenced Ms. Pfeuffer's and Ms. Uzenski's rebuttal testimony addressing the bases for Staff's disallowances, including DTE's "other cost" estimates and historic underspending. She further contended that by reducing the company's cost estimate based on the company's past failure to spend projected amounts for this project, Dr. Wang failed to address the causes of delay in 2020 and "assumes that these delays will continue in 2022 and 2023, without providing any supporting evidence." She reiterated the "mitigation measures" she explained in her direct testimony and again in response to Mr. Coppola, including the ClickSoft implementation, and modification of the project management process.[674]

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[671] 7 Tr 1542.
[672] 7 Tr 1541.
[673] 7 Tr 1541.
[674] 7 Tr 1543.

In its brief, DTE argues that the delays in the Compass tool were driven by the complexity of the technology, and further argues that it modified its project management process to ensure that OMS and DMS components will not be delayed further.[675] DTE argues that the Attorney General's disallowance should be rejected because the DMS/OMS provides benefits to customers and the Attorney General "did not provide any evidence showing any lack of customer value."[676] DTE further relies on Ms. Elliott Andahazy's rebuttal in asserting that the Attorney General's disallowance exceeds the increase in costs DTE is requesting, and ignores that ADMS is the essential technology to support the modern grid and to replace existing systems nearing end of life. DTE also reviews Ms. Elliott Andahazy's calculation of the increase to the company's initial projections, citing Schedule KK2 of Exhibit A-46.[677] DTE also objects to Staff's adjustments for the reasons explained in Ms. Elliott Andahazy's rebuttal.[678]

As discussed above, Staff argued the Commission should adopt its revised adjustment for this category. The Attorney General argues the Commission should adopt Mr. Coppola's recommendation, noting its relationship to his overall 20% reduction, but also urging the Commission to direct the company to provide a full accounting of the OMS/DMS project costs with sufficient detail to allow for a thorough prudency review of the actual expenditures relative to the initial project costs approved in Case No. U-20162. The Attorney General cites discovery responses DTE provided

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[675] DTE brief 90.
[676] DTE brief, 91.
[677] DTE brief, 91-92.
[678] DTE brief, 93; also see DTE reply, 76-79.

regarding Ms. Elliott Andahazy's rebuttal in Exhibit AG-1.59 to show she wrongly contended Mr. Coppola was proposing to disallow capital the company already spent.[679]

This PFD finds that DTE has not justified the additional costs it now projects for this project. DTE seems to acknowledge it is standard industry practice to hire a System Administrator when implementing ADMS, yet DTE did not retain one until 2020, well into the project and well after the first version of OMS was supposed to be approved.[680] Nor has DTE explained whether it took any contractual steps or has identified any contractual remedies associated with the delay. For these reasons, it has failed to show that it reasonably and prudently implemented this project, and the cost overruns should not be funded by ratepayers. This PFD recognizes that DTE has not completed its efforts to implement OMS; it should be allowed to seek recovery of the total project costs following that implementation, with a detailed presentation to show how it protected ratepayer interests throughout the project.

iii. ADMS: Network management system (B5.4, page 11, line 3)

As described by DTE, NMS "allows the Company to maintain high quality system data, which is essential to the safe and effective monitoring and operations of the grid."[681] While Ms. Elliott Andahazy testified that implementation of NMS was completed in 2020, she further testified that the company has included an additional $6.3 million funding request in this case:

> The initial NMS project set the foundation for the Company to maintain high quality system data, which is essential to the safe and effective monitoring and operation of the electrical grid. This source data is imported into the DMS Network Model application and is the basis for the

[679] Attorney General brief, 52-53.
[680] Elliott Andahazy, 7 Tr 1498.
[681] 7 Tr 1492.

outputs of all other ADMS applications. It is imperative to have high quality data in the Network Model to ensure safe reliable, and accurate interpretation of the current status of the system when utilizing the ADMS in daily operations. This additional investment, totaling $6.3 million in years 2021-2023, will support further development of high-quality data in the Network Model that was not included in the original scope of the NMS project.[682]

She testified that the enhancements covered by this funding "are required to support and realize the full customer benefits of the ADMS as detailed in Table 1 [at 7 Tr 1494] and to support timely studies of customer requests to connect to the grid through the distribution planning process."[683]

As shown in Exhibits S-7.40 and S-7.42, Staff's reductions to the projected expenditures for this line item of $0.73 million for the bridge period and $0.71 million for the test year reflect Staff's limit on the loading for "other costs" and a 20% reduction due to Staff's assessment that the company's cost estimate is at a high level, with associated uncertainty.

Mr. Coppola recommended that the Commission reject the additional $6.3 million in expenditures for this project as described by Ms. Elliott Andahazy. Citing Exhibit AG-1.18, he explained his conclusion that the company had failed to support this request:

> The Company spent $17.5 million to gather supposedly high-quality system data and now states that it should have gathered more data but cannot clearly define what that data is. In discovery, the Company was asked in several discovery questions to clearly identify the additional data it seeks to include in the NMS and the value of that data. The discovery responses do not add any more light or specific information about the additional data that the Company wants to gather now.
>
> Additionally, the Company now seems to want to add new functionality and features to the system that it did not find necessary in the initial scope

[682] 7 Tr 1498-1499.
[683] 7 Tr 1500.

> of the project. The additional features seem to be advanced planning tools, digital maps, and diagrams to display sections of the distribution grid. It is perplexing why, if these features are valuable, they were not included the original scope of the project. In discovery, the Company was asked to provide a copy of the cost/benefit analysis to show that the additional $6.3 million in capital spending was economically justified. The Company answered that it had not calculated the direct financial benefits of this project and referenced two other discovery responses. In discovery responses STDE-4.4d and 4.1a, the Company stated it would need 12 employees to manage the data if the NMS expansion was not done. There were no details provided to support that conclusion.[684]

His rejection of this expenditure equated to a $2.33 million reduction to the bridge period projection and a $2.88 million reduction to the test year projection for this line item.[685]

In rebuttal, Ms. Elliott Andahazy contended that the company had provided adequate detail regarding the additional expenditures for this project, citing discovery responses the company provided as included in Exhibit A-46, Schedule KK1, and asserting that it is reasonable for data requirements to evolve over time.[686]

In response to Staff's adjustment, in addition to Ms. Pfeuffer's and Ms. Uzenski's rebuttal testimony responding to the bases for Staff's concerns, as discussed above, Ms. Elliott Andahazy disputed that the company's cost projection is based on a "high-level" estimate, noting that the company spent 133% of what it projected for 2020 under Staff's analysis. She also noted that Dr. Wang discussed this project with approval in the context of discussing the internet process enablement project.[687]

DTE relies on Ms. Elliott Andahazy's testimony, arguing it is reasonable for the NMS data requirements to evolve after the initial project scope, and reiterating its

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[684] 8 Tr 4765-4766.
[685] 8 Tr 4766-4767.
[686] 7 Tr 1536-1537.
[687] 7 Tr 1538.

objections to Staff's adjustments.[688] As part of DTE's response to Staff's reliance on historical underspending for certain projects, DTE argues that looking at the company's level of historical overspending on this project of 133.8%, Staff should increase the company's projection in this case by that amount.[689] DTE then acknowledges that Staff's adjustment in this case is based on Staff's view that DTE's cost estimate is high level and thus uncertain, citing Ms. Elliott Andahazy's testimony disputing that characterization.[690]

The Attorney General argues that DTE did not establish that the additional $6.3 million in spending on NMS is justified. The Attorney General cites discovery in Exhibit AG-1.59, page 1, as confirmation that Ms. Elliott Andahazy believes spending on new technologies should occur in the absence of quantifiable financial benefits. The Attorney General characterizes the benefits DTE has identified as non-financial, arbitrary, and vague:

> [Ms. Elliott Andahzay] wants to rely on non-financial benefits, such as arbitrary projected reductions in SAIDI minutes, which cannot be readily measured subsequent to the implementation of the ADMS. Other potential benefits mentioned in her testimony are also vague with no specific amounts or quantities.[691]

DTE disputes the Attorney General's contention, relying on Ms. Elliott Andahazy's rebuttal as well as her Schedule KK1 in Exhibit A-46.[692]

This PFD finds the Attorney General's analysis persuasive to establish that DTE has failed to justify the additional spending for this project relative to its initial scope. Mr.

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688 DTE brief, 89-90.
689 DTE brief, 74.
690 DTE brief, 90.
691 Attorney General brief, 51-52.
692 DTE brief, 89-90; DTE reply, 75-76.

Coppola made clear he reviewed the company's discovery responses regarding this project.[693] Consistent with the discussion of DTE's IT projections in subsection F below, DTE's discussions of its project benefits do not readily allow for evaluation of the benefits of this project relative to the many other DTE projects that similarly promote savings, and the company's decision not to provide any quantification of the project benefits also frustrates review.

iv. SOC: ESOC and SOC:ASOC (B5.4, page 11, lines 4 and 5)

These two line items are discussed together because they were originally treated by DTE as a single project, the system operations center (SOC) modernization project, approved in Case Nos. U-20162 and U-20561. Ms. Elliott Andahazy explained that the project "aimed at replacing the Company's outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current industry security, resiliency, and operability standards."[694] She described limitations of the current facilities,[695] testifying that DTE identified these limitations "through extensive benchmarking at the inception of the project."[696] She further testified that the project was initiated in 2017, with planned construction and occupancy of the primary "Electric System Operations Center" (ESOC) by December 2019 and of the backup "Alternate System Operations Center" (ASOC) by December 2020.[697]

After describing progress to date, she testified that construction of the ESOC is complete, with central dispatch personnel and half of the operational engineering

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[693] 8 Tr 4765-4766.
[694] 7 Tr 1518.
[695] 7 Tr 1519-1520.
[696] 7 Tr 1519.
[697] 7 Tr 1520.

employees working in the space, while "IT is installing the remaining equipment" as she described in further detail.[698] Ms. Elliott Andahazy acknowledged delays and cost overruns for the project. She attributed the ESOC delays to "building design adjustments," "permit timing," the discovery of "below-grade obstructions," and the need for "environmental remediation," as well as COVID-related delays.[699] As to the building cost, she testified that in Case No. U-20561, the company projected a total cost for both the ESOC and ASOC of $110.7 million—$78 million for the ESOC and $33 million for the ASOC—with $106.9 million included in rate base in that case. As shown in Table 5 of her testimony at 7 Tr 1523, the ESOC is now projected to cost $98.5 million. She attributed the increased cost to "construction delays due to COVID," and several other items including "an increase in square footage, additional testing and permitting, and a new IT datacenter with additional integration efforts."[700] Ms. Elliott Andahazy then explained the square footage of the ESOC was increased by 21,000 square feet, or approximately 50%, to accommodate space for additional personnel:

> As the Company continued to evaluate the learnings from benchmarking other utilities, DTE Electric determined that additional benefits could be realized if critical support personnel were also co-located within the ESOC.[701]

She emphasized the importance of colocating critical support personnel. She testified that the addition of approximately 60 employees to the design "in turn drove an increase in IT costs for that same number of computers, monitors, peripherals and their

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698 7 Tr 1520.
699 7 Tr 1521.
700 7 Tr 1522, 1523.
701 7 Tr 1524.

associated infrastructure, including labor to provision and install that equipment."[702] She further testified that after the project began, DTE also decided to add a "fully integrated datacenter," which "brought with it additional material investments for that location including HVAC, Equipment racking, cabling, servers, storage, and all of the other support equipment needed to activate a modern datacenter for this facility while meeting all of the NERC certification requirements."[703]

Turning to the ASOC, she testified that a new facility is still needed to back up the ESOC, citing the reasons identified by Mr. Bruzzano in Case No U-20561. She testified that "the ASOC was still in its conceptual design phase when MPSC Case No. U-20561 was submitted,"[704] and acknowledged that the project is still in the conceptual design phase.[705] She testified that with the need to provide for additional employees at the backup facility, following the expansion of the ESOC, DTE has moved the location of the ASOC to connect to its Waterford service center:

> Once the Company obtained a full design with appropriate requirements, the forecasted costs were significantly higher than what was initially presented. By Constructing the ASOC at the same location as the new proposed Waterford service center, the Company will be able to leverage synergies in construction and reduce overall costs closer to the initial estimates provided in MPSC Case No. U-20561.[706]

She testified that the company's rate case projections in this case include $34.5 million for this project, $22.1 million above historical expenditures.

Mr. Coppola objected to the projected funding for the ESOC and ASOC, characterizing the delays and cost overruns as of the company's own making. He

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[702] 7 Tr 1525.
[703] 7 Tr 1526-1527.
[704] 7 Tr 1528.
[705] 7 Tr 1529.
[706] 7 Tr 1528-1529.

considered Ms. Elliott Andahazy's testimony that the company continued to evaluate the facility designs after submitting its proposal in prior rate cases to be an acknowledgement that the company's proposals were incomplete and premature. Citing company discovery responses in Exhibit AG-1.10, he provided a breakdown of the additional $20.5 million in projected ESOC costs:

> The schedule provided in response to AGDE-7.215c shows $1.4 million in additional costs for an engineer onsite to oversee and support construction activities; $11.1 million for additional construction costs for the added space, additional permitting costs, and control room equipment; $3.7 million for additional IT equipment for the stand-alone data center; and $4.3 million for additional overheads and AFUDC pertaining to the project cost increase.[707]

He noted that the company only attributes $923,000 of its additional costs to COVID, also pointing out that if the company had met its initial timeframe, COVID would not have been an issue. He concluded that the company did not justify the expanded size of the facility, the relocation of additional employees, or the new data center. He recommended that the Commission disallow the entire $20.5 million in additional costs for the project over the amount approved in Case No. U-20561 as imprudently incurred.[708]

Dr. Wang explained Staff's recommended reductions to the company's projected expenses for these line items. For the ESOC, she recommended a reduction of $14.4 million for the bridge period and $62,000 for the test year. She expressed skepticism that DTE's design changes were motivated by benchmarking, citing testimony from Case Nos. U-20162 and U-20561 to show that colocation was one of the four

[707] 8 Tr 4772.
[708] 8 Tr 4773-4774.

motivations the company provided for the project in those cases.[709] Dr. Wang testified that the company did not quantify any additional benefits from the expansion of the facility or to relate the expansion to industry best practices.[710] She further testified that the additional 21,000 square feet was more than necessary to add 60 employees, and noted that the prior ESOC design included over 1,300 square feet of shared space for collaborations and meetings.[711]

Dr. Wang also compared the size of the facility to the benchmarking data from other utilities that DTE provided in discovery, reproduced at Table 1 of her testimony at 8 Tr 5202. She concluded that the redesign is larger than the average benchmarked SOC by approximately 12,000 square feet. She also noted a number of colocated employees who are currently working remotely. In this context, she testified that the pandemic has shown that face-to-face engagement is no longer necessary for work efficiency and collaboration, citing the company's safe grid operations during the pandemic.[712] Dr. Wang also testified that by delaying the project for this design change, the company missed the opportunity to have completed the ESOC before the pandemic, which thus delayed the associated reliability, resilience, and efficiency benefits to ratepayers in addition to increasing construction costs, while achieving limited and unquantified efficiency gains.[713] Dr. Wang testified that Staff recommends that the costs of the redesign be excluded from rate base, and explained the calculations underlying Staff's recommended disallowance.

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[709] 8 Tr 5199-5201.
[710] 8 Tr 5200.
[711] 8 Tr 5201.
[712] 8 Tr 5203-5204.
[713] 8 Tr 5205-5207.

Regarding the ASOC project, Dr. Wang acknowledged a high possibility that the ASOC costs may not actually occur.[714] She testified that Staff recommends a reduction of two-thirds in the projected costs, resulting in Staff's proposed reduction of $5.9 million in the projected bridge period and $14.42 million in the test year, noting that the company could seek to include actual, reasonable and prudent expenditures in a subsequent rate case.[715]

In rebuttal, Ms. Elliott Andahazy testified that she provided support for the increased square footage in her direct testimony at 7 Tr 1524-1527, and also cited Schedule KK3 of Exhibit A-46.[716] Acknowledging uncertainty whether a hybrid work model will continue, she testified that all employees could work at the ESOC if the situation requires.[717] Regarding Staff's $14.4 million reduction to the bridge period capital projection, Ms. Elliott Andahazy characterized it as "essentially a total disallowance of the capital investment, which are largely historical."[718] She also testified that the table presented in Dr. Wang's testimony at 8 Tr 5202 "is a subset of all utilities benchmarked by the Company." She cited Mr. Bruzzano's direct testimony from Case No. U-20162 as support for the company's benchmarking and further stated that the table "provides no context on size of the company and how many customers are served, the size/type of system which determines the North American Electric Reliability Corporation (NERC) operational entity, or volume of day-to-day emergent trouble."[719] She asserted on this basis that it is not reasonable to use the average size of these

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[714] 8 Tr 5208.
[715] 8 Tr 5208.
[716] 7 Tr 1545-1546.
[717] 7 Tr 1546.
[718] 7 Tr 1548.
[719] 7 Tr 1548-1549.

control facilities “as the basis for rationalizing the size of the Company’s ESOC.”[720] She also disputed that the company considered aesthetics in expanding the size of the facility.

Regarding the ASOC, Ms. Elliott Andahazy objected that Staff had not provided “data or analytics” underlying the calculation of the two-thirds reduction in bridge and test year spending. She also considered Dr. Wang’s statement that having completed the ESOC, the company would likely turn its attention to the ASOC, as a contradiction of Staff’s concern that the investment might not occur.

In its brief, DTE relies on Ms. Elliott Andahazy’s testimony, including her rebuttal, arguing both facilities are justified and should be fully funded. Responding to Mr. Coppola’s testimony, DTE argues that details regarding the expanded scope of the project were provided in Ms. Elliott Andahazy’s direct testimony and in discovery as shown by Schedule KK3 of Exhibit A-46. It also relies on its benchmarking to show the need to colocate personnel. It contends that notwithstanding staff currently working from home, the building needs to be sized to accommodate everyone when necessary. Regarding Staff’s analysis, DTE also argues that it only provided Staff some of the benchmarking it relied on for the facility size in response to discovery, as shown in Schedule KK3, contending the table “provides no context on the size of the company, how many customers each serves, the size/type of system . . . or volume of day-to-day emergent trouble.”[721] It also relies on Ms. Elliott Andahazy’s testimony to support its claim that the redesign was driven by operational efficiencies.

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[720] 7 Tr 1549.
[721] DTE brief, 97-98.

Regarding the ASOC project, DTE contends that Staff "did not offer any data or analytics to support its proposed 66% disallowance, but instead simply indicated its belief that the investment might not happen," arguing that "[t]here is also not reason to think that construction of the ASOC will not occur" because DTE is obligated to meet NERC requirements.[722] It argues groundbreaking is planned for early 2023, citing "discovery of inflated costs associated with the original project," as the basis for delay.[723]

The Attorney General argues that DTE has not justified the scope change, or the tangible benefits from the added size of the facility, relation of additional personnel and the inclusion of a stand-alone data center.[724] The Attorney General also cites discovery in Exhibit AG-1.59, page 4, to show that employees have not actually moved into the space as expected.

Citing Dr. Wang's testimony and exhibits, Staff argues that the Commission should adopt its recommendations regarding both the ESOC and ASOC.[725] It argues that ratepayers should not bear the risks and consequences of the company's design decision, "which delayed the benefits of a modernized SOC for unquantified and likely limited benefit." Staff argues that efficiency gains DTE cites for colocating additional personnel relative to the original design "are unquantified and likely limited," with 50% of the colocated personnel working remotely. Staff also contends the redesign is larger than needed. Addressing DTE's rebuttal, Staff argues that DTE has still not provided the benchmarking data it now claims to rely on, and explains that DTE's discovery response

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[722] DTE brief, 99.
[723] DTE brief, 99.
[724] Attorney General brief, 53-54.
[725] Staff brief, 63-68.

in Exhibit S-7.22, contained the benchmarking data DTE purported to have relied on in the design.[726] Staff disputes DTE's claim that the relocation of employees was the sole justification for the redesign, arguing it has 4,680 square feet more than required for those employees.[727]

Regarding the ASOC cost projection, Staff argues that while costs were included in rates in Case No. U-20561, the project remains in a conceptual design phase. It argues that while it could recommended a full disallowance, "Staff believes the Company will turn its attention to the construction and occupancy of the ASOC soon, as the ESOC is near completion."[728] Nonetheless, after reviewing DTE's rebuttal testimony, including its argument that Staff did not provide support for a 2/3 disallowance, Staff argues that a full disallowance is "better supported by the evidence in the case, addresses the Company's rebuttal concerns, and best protects ratepayer interest."[729]

In its reply brief, DTE contends the Attorney General's characterization of staffing at the ESOC misleading because the building was not complete in 2021, citing Exhibit AG-1.59. It characterizes Staff's argument as "add[ing] only an additional layer of unfounded speculation," maintaining that it established the reasonableness and prudence of its expenditures by a preponderance of the evidence.[730] Regarding the ASOC, DTE argues that Staff is inconsistent in "proposing a disallowance due to alleged uncertainty regarding whether costs will materialize, but at the same time stating that it 'believes the Company will turn its attention to construction and occupancy of the

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[726] Staff brief, 64-65.
[727] Staff brief, 65.
[728] Staff brief, 67, citing Dr. Wang at 8 Tr 5208.
[729] Staff brief, 68.
[730] DTE reply, 83.

ASOC soon.'"[731] As in its initial brief, DTE argues that "there is no reason to think that construction will not occur" because of NERC requirements, and because DTE established the need for the ASOC in Case Nos. U-20162 and U-20561.

First, this PFD finds that it is premature to include any funding for the ASOC. As Staff argues, DTE is still in the preliminary design stage, it does not anticipate groundbreaking until 2023, and has a history of not executing this project as planned. If DTE has concrete plans and a firm construction schedule by the time its next case rolls around, it will have the opportunity to seek cost recovery at that point. Exhibit AG-1.10, page 3, states that the design work would begin in May 2022, with completion expected in 2024.

This PFD also notes for completeness that Ms. Elliott Andahazy testified:

> [T]he ASOC was still in conceptual design phase when MPSC Case No. U-20561 was submitted. Once the Company obtained a full design with appropriate requirements, the forecasted costs were significantly higher than what was initially presented. By constructing the ASOC at the same location as the new proposed Waterford service center, the company will be able to leverage synergies in construction and reduce overall costs closer in alignment to the initial estimates provided in MPSC Case No. U-20561. This new location still allows the control room to relocate in case of an emergency a reasonable amount of time to not affect operations, and the shared space in the new service center will allow for the co-location of the critical support staff as well.[732]

This explanation followed her testimony that:

> The planned location of the new ASOC has shifted from a site near the exhibits backup SOC, to be connected to the new Waterford Service center (as discussed in Company Witness Uzenski's testimony). The ASOC will be located approximately 25 miles away from the new ESOC and will allow the Company to safely operate the grid in case of a major adverse event at ESOC.[733]

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[731] DTE reply, 83.
[732] 7 Tr 1528-1529.
[733] 7 Tr 1528.

A review of Mr. Bruzzano's testimony in Case No. U-20561, however, shows that DTE already planned to move the ASOC to a location "approximately 25 miles away from the primary facility," with Mr. Bruzzano adding that this "will allow the Company to safely operate the grid in the case of a major adverse event at the primary SOC."[734] Although not part of the facts underlying this PFD's conclusion that the ASOC costs should not be included in rate base, this PFD finds that DTE has not been candid regarding the changes it made to this project.

Turning to the ESOC, this PFD finds that DTE has not justified the expansion of this project and the associated expenses. DTE's credibility regarding the basis for its design is impaired by its failure to provide the benchmarking data that it claims to rely on to support the size of the facility and the colocation of the additional employees not envisioned in the original plan. The company's claim is further impaired by its disavowal of the benchmarking information it provided to Staff on request. As Staff argues, in Exhibit S-7.22, DTE stated that it was providing "[t]he benchmarking data compiled when in the design phase of the ESOC." While Staff asked for information on the number of employees working in each of the identified utility centers, DTE's response noted that "the Company does not have the number of people working within the centers on a daily basis." This limited amount of information contradicts DTE's claim to have undertaken extensive benchmarking, as Ms. Elliott Andahazy stated as the basis for the ESOC design and redesign. [735]

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[734] Case No. U-20561, Docket Entry # 0386, transcript volume 4 at 199.
[735] 7 Tr 1518 Elliott Andahazy, 7 Tr 1519 ("through extensive benchmarking at the inception of the project,") and 7 Tr 1524 ("continued to evaluate the learnings from benchmarking other utilities").

DTE relies on the Commission's approval of the ESOC in Case Nos. U-20162 and U-20561. In her direct testimony, Ms. Elliott Andahazy testified that the SOC project was addressed extensively by Mr. Bruzzano in Case Nos. U-20162 and U-20561. She goes on to cite the Commission's May 2, 2019 order in Case No. U-20162, which stressed "the need for and importance of this modification project for system operations from a reliability and resiliency standpoint."[736] A review of DTE's last rate case shows that Mr. Bruzzano acknowledged the project had been delayed in his direct testimony. Indeed, Mr. Bruzzano testified that the delay was "due to building design adjustments and permit timing," but asserted that ground had been broken on the project May 28, 2019.[737] DTE did not revise its expense projection in that case, which indicates that the cost overruns it now blames on design changes were either known to DTE at the time it filed that rate case in July 2019, and DTE misrepresented the associated costs, or they were merely cost overruns that DTE has failed to explain on this record.

DTE presents several of its discovery responses as rebuttal exhibits in this case. As shown in Schedule KK3 of Exhibit A46, page 6, when asked by Staff when it determined the design changes were needed, DTE did not provide an answer:

> Q: Please describe when the Company learned that it is more efficient to have all critical personnel who work on Control Room processes in the same facility. Please also describe why the Company did not find it important to have additional critical support staff co-located with other Control Room staff in its original design of the new ESOC.
>
> A: DTE continuously adapts to the needs of its customers and changing regulatory requirements such as those presented in FERCC order 2222. It continually benchmarks other utilities based on these changes to better

[736] May 2, 2019 order, Case No. U-20162, page 30. The Commission's statement was made in the context of addressing the Attorney General's concern, raised untimely, that the project would exceed its budget.
[737] Case No. U-20561, Docket Entry # 0386, transcript volume 4 at 162,197.

> understand what is needed to operate and maintain the future ADMS system and the grid of the future. This additional benchmarking with EPRI member utilities surfaced the criticality that having support roles in ESOC has on meeting those needs through collaboration and real time support of these personnel in ESOC.

In Schedule KK3 of Exhibit A-46, page 2, moreover, DTE stated:

> At the time of MPSC Case No. U-20561, the ESOC was in the initial design phase. The Company continued to evaluate learnings from benchmarking and determined the importance of the co-location of other critical support personnel. The company has not calculated cost savings due to the co-location of these additional employees.

This PFD finds that DTE has not established a basis for the cost overruns for this project relative to the costs included in Case No. U-20561, and concludes that the Commission should adopt the disallowance for the ESOC recommended by Staff and the Attorney General.

v. Grid Automation telecommunications (B5.4, page 11, line 6)

Ms. Pfeuffer addressed the grid automation telecommunications program, explaining the company's plan to extend its fiber ring to prioritized locations, to support remote monitoring and control as well as greater cybersecurity. She testified that DTE connected 27 substations and installed 72 miles of fiber in 2021, with plans to install 500 miles of fiber for 230 substations and other critical equipment over the next 10 years.[738] As shown in Schedule B5.4, page 11, DTE projected spending of $21.46 million in the 22-month bridge period and $18.38 million in the test year. As with other strategic capital expense projections, Ms. Pfeuffer cited the DGP in Schedule M1 of Exhibit A-23.[739]

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[738] 8 Tr 348-351.
[739] 4 Tr 371.

Citing Exhibit S-7.27, Dr. Wang noted that by March 2022, DTE had spent only 37% of the amount it projected for that period, and concluded that the project is not on track to meet its rate case projections. She recommended using the 37% as the measure by which to reduce the company's bridge and test year projections, resulting in reductions of $13.54 million and $11.59 million respectively.[740]

As noted above, Ms. Pfeuffer objected to Staff's reliance on historic projection accuracy generally. In addition to discussing that objection in its brief, DTE reviews the purpose of the program, citing Ms. Pfeuffer's testimony.[741] Staff considers that DTE did not address its adjustment for this line item.[742] In its reply brief, DTE essentially repeats the basis for the program.[743] This PFD finds Staff's reduction reasonably tailors the future projections to the current pace of spending, and should be adopted.

vi. CVR/VVO (B5.4, page 11, line 11)

Ms. Pfeuffer explained that DTE has been evaluating the use of Conservation Voltage Reduction (CVR) and Volt Var Optimization (VVO) to reduce peak demand and energy consumption as an alternative to new generation as part of its Integrated Resource Plan approved in Case No. U-20471.[744] She described the company's pilot, with the completed third-party evaluation expected in 2021.[745] She testified that the company "plans to continue investments in CVR/VVO in 2022 and beyond," including investing in "a more advanced approach to CVR/VVO." She testified that in addition to completing the pilot in 2021, the company "installed CVR/VVO on 8 substation

[740] 8 Tr 5208-5209.
[741] DTE brief, 77-78.
[742] Staff brief, 69.
[743] DTE reply, 59.
[744] 8 Tr 355-359.
[745] 8 Tr 357.

transformers and 28 circuits in 2021, 18 substation transformers and 56 circuits in 2022, 44 substation transformers and 136 circuits in 2023."[746] Notwithstanding her use of the past tense, she testified that "the CVR/VVO implementation for selected substations will include" certain equipment upgrades and remote controls,[747] and she explained that substations are prioritized based on their energy reduction potential "and synchronized with the substations selected for the substation automation program."[748] As shown in Schedule B5.4, page 11, DTE spent $4.5 million in 2021, and projects bridge period expenditures of $10.34 million and test year expenditures of $15.67 million.

After describing the program and projected expenditures, Mr. Evans testified that Staff recommends a $14.5 million reduction to the test year expense projection because the company did not identify the circuits and substations to be upgraded in 2023. He cited the company's discovery responses in Exhibits S-16.7 and S-16.8 to show that the company plans to select substations and circuits for 2023 in the third quarter of 2022. He explained: "Staff's position is that ratepayers should not have to pay for projects that are at such a preliminary stage that their locations are not even known."

In rebuttal, Ms. Pfeuffer disputed that the planning for 2023 was at a preliminary stage:

> The Company began the CVR/VVO project in 2019 by conducting field verification and detailed engineering studies on 18 circuits fed from six transformers, Exhibit A-23 Schedule M1 page 397. Since that time the Company has successfully invested to forecasts through 2021, investing $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). Additionally, the Company maintains a prioritized list of substations for CVR/VVO

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[746] 4 Tr 358.
[747] 4 Tr 358-359.
[748] 4 Tr 359.

> based on expected energy savings, which currently has 17 substations and 126 circuits identified for 2023.[749]

She further testified that selecting circuits from the prioritized list in the third quarter of 2022 "provides the Company sufficient time to plan for the work to be done in the coming year, while also allowing the Company to use the most current prioritization data in selecting circuits."[750] She asserted that selecting circuits "too soon" would lock the company in to work on circuits "that may not be the optimal choice."[751]

In its briefs, DTE relies on Ms. Pfeuffer's rebuttal testimony, aguing that Staff understands this is an established project, with a track record.[752] In its brief, Staff urges the Commission to adopt its recommendation, arguing that even though the project as a whole is not in a preliminary stage, "the fact that selection of the circuits and substations that will be upgraded has not even occurred yet makes those future projects preliminary. Staff also asks the Commission to require DTE to provide additional data regarding this program in its next rate case filing.[753]

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

vii. NWA: O'Shea energy storage (B5.4, page 11, line 12)

Ms. Pfeuffer described the company's non-wires alternative (NWA) pilot programs, one of which is the O'Shea energy storage project.[754] She cited the

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[749] 4 Tr 488.
[750] 4 Tr 489.
[751] 4 Tr 488-489.
[752] DTE brief, 78-80; DTE reply, 60-62.
[753] Staff brief, 45-47.
[754] 4 Tr 369.

Commission's order approving the company's IRP in Case No. U-20147, and testified that the company's objective is to incorporate NWA solutions into its grid planning process. She described the process DTE uses to develop pilot projects, and testified that eight pilots are currently planned, as shown in Table 17 of her testimony at 4 Tr 365-366. She described the results of a completed pilot, and the goals of the other pilots in this table. Table 17 identifies the O'Shea pilot as a storage pilot to "test effectiveness of storage to address voltage instability due to intermittent solar," planned for 2021-2022.[755] In Schedule B5.4.3 of Exhibit A-12, DTE did not provide cost detail or a timeline for this project, other than to assert it would be complete by early 2022.

Dr. Wang reviewed the cost projections for this pilot. She testified that since the battery has already been purchased, the remaining costs for this project are mostly labor and seem high to Staff. She testified that for the project, labor costs are approximately 2.8 times the materials cost. She looked to a 2020 U.S. Department of Energy report, which reported labor costs for a 1 MW battery installation as falling within the range of 9.2% to 12.7% of total installation costs. She testified as shown in Exhibit S-7.28, Staff used a labor cost percentage of 13%, plus an additional 5.17% for administrative and general and other overhead costs. The resulting cost estimate led to Staff's recommended capital expense reductions of $1.29 million for the bridge period and $16,257 for the test year.[756]

While DTE took issue with Staff's adjustment for "other costs" as discussed above, Ms. Pfeuffer did not explicitly address the O'Shea project in rebuttal, and DTE

[755] 8 Tr 366.
[756] 8 Tr 5210-5212.

does not address it directly in its brief. On this basis, given this PFD's acceptance of Staff's adjustment for the "other" cost category, this PFD finds this issue is resolved and Staff's adjustments to this line item should be adopted.

viii. NWA: Battery trailer (B5.4, page 11, line 13)

While Staff originally recommended an adjustment to this line item as shown in Exhibit S-7.42, Staff does not pursue this adjustment in its brief, so this PFD considers the issue resolved.

ix. NWA: Omega load relief (B5.4, page 11, line 14)

This NWA pilot is also included in Table 17 of Ms. Pfeuffer's direct testimony as a storage pilot "to address subtransmission loading" and to install a battery that can be relocated.[757] She also discussed the alternatives considered.[758] DTE projects bridge period spending of $7.1 million and test year spending of $670,000.

Dr. Wang testified that Staff's adjustment to this line item removed $2.37 million from the projected bridge period and $223,333 from the projected test year costs for this project to reflect that the project no longer includes a solar implementation.[759] She explained that Staff then adjusted the projected costs to match the labor percentage to the NWA: Battery Trailer project, resulting in further reductions of $1.69 million for the bridge period and $159,750 for the projected test year.[760] Staff's Exhibit S-7.42 also shows that Staff further reduced the expense projections by an additional 20% to reflect historical underspending in technology and automation projects.

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[757] 4 Tr 365.
[758] 4 Tr 368.
[759] 8 Tr 5212-5213.
[760] 8 Tr 5213.

Ms. Pfeuffer disputed that solar generation was ever part of the plan for this project:

> [A]s stated in Staff Witness Wang's Exhibit – S-7.30 response to STDE-15.35 "The project scope and associated costs does not include solar." The Company made clear that the project cost does not include any investment in solar capability through discovery responses such as the one quoted above. Additionally, the amount of one third proposed for the disallowance is an arbitrary value that does not, and in fact cannot, reflect the cost of solar related to this project since no such costs exist.[761]

She also testified that the labor component was higher for this project due to site preparation requirements:

> The labor cost for the Omega project includes site preparation, which entails cable and conduit installation and below grade work necessary to support trailers. The labor for the battery trailer project does not include site preparation costs, hence the difference in the labor cost. As described in Exhibit A-23, Schedule M1 on page 414, the Company plans to use mobile battery trailers for various use cases supporting the system needs including sitting in the place of portable generators, sitting at substations or on circuits.[762]

In its brief, Staff cites Schedule M6 of Exhibit A-23, page 52, to show that the company's "detail" for the project includes solar in the project scope:

> Including costs in rates for activities which the Company declares will not occur is unreasonable and imprudent. Given the contradictory exhibit and discovery information from the Company, Staff asserts the record fails to support the Company's request.[763]

Staff also argues that DTE did not break its capital costs down by scope item, limiting its ability to determine the full amount included in the project for solar. Staff also rejected

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[761] 4 Tr 471.
[762] 4 Tr 472.
[763] Staff brief, 72.

the company's claim regarding the labor component of the project, contending DTE did not provide adequate data to support its claim.[764] In its reply, DTE argues:

> Staff's response defies the record and fails to acknowledge indisputable differences between the projects. Saying that both projects include labor misses the relevant point – the Omega project includes site preparation at a real property location (and thus higher labor costs), and the battery trailer project does not include site preparation (and therefore does not include those higher costs). There is no sound basis for Staff to be "unmoved" by the Company's clear and definitive evidence, and in any event, the record firmly supports the Company's recovery.[765]

MI MAUI and Ann Arbor also argue that this project should be approved "without the proposed disallowances," but does not address the basis for Staff's adjustments.[766]

This PFD finds Staff's adjustment is reasonable, at least in part, given the paucity of information provided by DTE to support its cost projections for this project. Neither Schedule M1 of Exhibit A-23 nor Schedule B5.4.5 of Exhibit A-12 present a detailed cost estimate for this project. Schedule M6 provides only an unsupported breakdown of the projected test year expenses of $670,000 into labor, material, and other, less than 10% of the total project cost. DTE has acknowledged that its "engineering estimates" are "high level," has not explained how the estimates are determined, and it has not provided a cost breakdown by scope or project step or provided a project timeline. As noted above, DTE initially filed its projected 2022 and 2023 spending with a flat 75% labor, 15% material, 10% overhead projection. While Schedule B5.4.5 reports "engineering and design" costs of $0.8 million, the engineering and design phase is not included in the project timeline, which includes only two steps, "install" and "operate."

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[764] Staff brief, 73.
[765] DTE reply, 67.
[766] MI MAUI brief, 28.

This PFD agrees with Staff that DTE bears responsibility for the confusion regarding the scope of this project. DTE filed an amended version of Schedule M6 on April 5, 2022—it could have eliminated the scope elements "2MW utility scale solar site at Gibraltar trade center," and "[i]f site not available rooftop solar options will be pursued." Nonetheless, it does appear that DTE did not intend this project to include a solar component. Schedule M1, page 411, contains a cost estimate of $7 million for the project, and does not include solar in the project scope. Schedule B.5.4.5 contains a cost estimate of $7.8 million, with a limited breakdown showing: "2 battery systems - $5.7 million; install batteries - $1.3 million; engineering and design - $0.8 million."[767] Thus, this PFD finds that Staff's adjustment for the scope of the project should be rejected, and Staff's remaining adjustments to this line item should be accepted.

DTE seems to defend the labor allocation in Schedule M6, page 54, although that schedule only has a breakdown of test year project costs of $670,000, with no cost detail for the bridge period projection of $7 million and does not explain the basis for the allocation. DTE's general assertion regarding site preparation being labor intensive is untimely, given all the opportunities—in multiple documents it filed for this project—the company had available to provide meaningful cost detail. Based on Exhibit S-7.2, this PFD finds that bridge period projections should be reduced by$2.48 million and test year projections should be reduced by $234,553.

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[767]Schedule B5.4.5, Exhibit A-12, page 2.

x. NWA: Fisher load relief (B5.4, page 11, line 15)

While Staff originally recommended an adjustment to this line item as shown in Exhibit S-7.42, Staff does not pursue this adjustment in its brief, so this PFD considers the issue resolved.

xi. NWA: Port Austin load relief (B5.4, page 11, line 16)

The Port Austin project as shown in Table 17 of Ms. Pfeuffer's direct testimony is scheduled for 2022-2025, and it is characterized as for both storage and solar. The project goals are to test solar and storage to address substation capacity, and to test redeployment of the stationary battery from Omega. Ms. Pfeuffer testified that for these pilots, generally the company plans to reuse the mobile battery system. For the Port Austin project, she explained:

> The use of the mobile batteries to manage demand was selected as an alternative to mitigate the risk, develop the use of the technology, and prepare the equipment for re-deployment for other pilot use cases. Following completion of the traditional system upgrades at Omega, one of the battery systems placed at Omega will be moved to Port Austin to address a substation that is over its firm rating. The alternative to address this over firm rating situation and voltage concerns is to convert the substation and circuits from 4.8kV to 13.2kV as part of the Conversion program. The construction at Port Austin will be done with conversion expected in the future, but the NWA option provides the opportunity to defer this investment to better meet the current and expected load, as well as other priorities.[768]

Dr. Wang testified that because completion of the NWA Port Austin load relief project is dependent on completion of the NWA Omega load relief pilot, scheduled to be completed by August 2022, Staff recommends excluding the costs associated with re-use of the battery from the Omega project from rate base:

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[768] 4 Tr 368.

> Though Staff hopes the NWA: Omega Load Relief project will be successfully completed, there is the possibility that it will not be completed successfully or on time. This would cause the costs associated with the re-use of the Omega battery in the NWA: Port Austin Load Relief project to not materialize, making it not reasonable or prudent to include in rates at this time.
>
> Since only the cost of the solar installation and battery re-use are within this rate case periods, and the solar scope is estimated to cost $2 million, Staff recommends all costs outside of the $2 million be disallowed. This yields a recommended disallowance of $2,083,000 in the test year for the NWA: Port Austin Load Relief project.[769]

In rebuttal, Ms. Pfeuffer disputed that Staff's disallowance reflected the costs associated with the battery installation, characterizing that cost as a small fraction of the disallowance.[770] She further testified that there is plenty of time between the completion of subtransmission line upgrades for Omega in 2023, when the battery will no longer needed, and the expected installation at Port Austin, to accommodate the types of delay that could potentially occur. She testified that if the battery were unavailable when needed, "the Company would simply procure a new battery, the costs of which would exceed the currently expected battery transportation costs."[771]

In its brief, after citing Dr. Wang's testimony at 8 Tr 5214 and Exhibit S-7.32, Staff addressed DTE's rebuttal, arguing that Staff is not objecting to the inclusion of a battery component in the project, but to the reasonableness and prudence of including costs that may not materialize in rates.[772] MI MAUI and Ann Arbor also argue that this

[769] 8 Tr 5214.
[770] 4 Tr 473.
[771] 4 Tr 474.
[772] Staff brief, 74-76.

project should be approved "without the proposed disallowances" but does not address the basis for Staff's recommendations.[773]

In its reply brief, DTE further contends that Staff is raising a criticism in its brief that was not raised in its testimony, further arguing that imposing any limit on including the project costs in rate base because the project might not be completed in the test year is a "suggestion of a 'used and useful' requirement" that DTE asserts is "contrary to controlling law."[774]

This PFD finds Staff's analysis persuasive. DTE has not established that its actual spending will align with the amounts forecasted. As stated in the company's DGP, the pilot has certain goals: "test solar and storage to address substation capacity," and "test redeployment of stationary battery from Omega."[775] Part of the pilot goals would be abrogated if DTE were to procure a new battery due to time constraints. DTE has not established that this program is expected to be in place during the projected test year, so a delay beyond the end of the test year is not incompatible with the project as described. Indeed, its project timeline had property search and conceptual engineering scheduled for 2021-2022, with detail design, property purchase, site prep, and the start of construction scheduled for 2022, with completion of the solar installation and completion of the battery installation scheduled for 2023.[776] DTE's projected $4.5 million cost is not broken down by any specific tasks, including engineering costs or land acquisition costs, or site preparation costs. A review of DTE's rebuttal exhibit, Exhibit A-52, page 12, shows no money spent in 2021 on this project, so it is unclear whether the

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[773] MI MAUI brief, 28.
[774] DTE reply, 69.
[775] Exhibit A-23, Schedule M1, page 403.
[776] Schedule B5.4.7, page 2.

limited timeline provided is still on track, including whether the engineering has been completed to produce a more accurate cost estimate. Schedule M6 of Exhibit A-23, as noted above, only contains projected test year costs.

xii. NWA: Veridian (B5.4, page 11, line 17)

Table 17 of Ms. Pfeuffer's direct testimony shows the Veridian NWA pilot as intended to "develop security and effective methods to interface and control behind the meter (BTM) DER is conjunction with utility scale DER," with pilot timing shown as 2021-2025.[777] As shown in Schedule B5.4, page 11, line 17, DTE projects bridge-period spending of $1.53 million and test year spending of $4.95 million for this project. Ms. Pfeuffer did not discuss this project status in her direct testimony. She did state that "The pilots are fully described in Exhibit A-12 and the DGP, Section 12.7."[778]

Dr. Wang explained that Staff's recommended reduction of $1.53 million to the bridge period and $4.95 million to the test year projections for this line item are based solely on the lack of internal company approval for the project, as shown in Exhibit S-7.4. In rebuttal, Ms. Pfeuffer testified that the project has subsequently received internal approval:

> [S]ince the initial filing and the Company's response to discovery question STDE-1.35 (Exhibit S-7.4), the Company internally approved the project. In February 2022, the developer officially submitted a request for the residential subdivision; and design for this portion of the project began in March 2022. Following the developer initiating this request, DTE Electric started the conceptual engineering for the microgrid aspects of the project with internal approval for detail engineering being received on May 11, 2022. The microgrid portion of this project, including circuit upgrades are almost ready to begin detail design with construction expected to start early 2023.[779]

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[777] 4 Tr 365.
[778] 4 Tr 364.
[779] 4 Tr 476.

DTE relies on this rebuttal in its brief.[780]

Ann Arbor witness Mr. Grocoff also addressed this project, as noted above, which involves his neighborhood. In its reply brief, MI MAUI and Ann Arbor argue:

> Ann Arbor finds the general thinking behind the Veridian NWA project to be good: instead of requiring a very expensive standard interconnection for a housing development with very innovative energy elements and high electrification, the interconnection procedures would allow creation of a microgrid that takes advantage of the solar and storage that is behind the meter. DTE should be given confidence that it can pursue interconnection of this project in an innovative way. See DTE's Br. 84-85.
>
> Ann Arbor also recognizes the troublesome nature of approving costs based on a design that is not final and Staff's concerns regarding the lack of certainty regarding what the end costs will be. Staff Br. at 47. Ann Arbor also recognizes the vital need for certainty for Veridian regarding costs and final design requirements for interconnection in the very near term.
>
> Given that all parties appear supportive of allowing DTE to innovate while hooking up Veridian to the grid, but there are legitimate concerns about approving costs that have not yet been incurred based on a design that may not be final, Ann Arbor recommends the Commission approve the Veridian NWA, but with a provision that requires additional filings by DTE in the next rate case regarding the project's execution, with the option of reductions in the revenue requirements in that case if costs exceed current projections.[781]

In its brief, DTE also cites a discovery response from Mr. Grocoff in Exhibit A-51 to show the project is proceeding.

Staff recommends that the projected costs for this project be excluded from rate base, relying on Dr. Wang's testimony that the project had not been approved at the time of filing. Staff acknowledges Ms. Pfeuffer's testimony at 4 Tr 476 indicating that internal approval for the project was granted on May 11, 2022, eight days before Staff

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[780] DTE brief, 84-85.
[781] Mi MAUI reply, 19-20.

testimony was due. Staff argues that DTE did not provide documentation of this approval or details on the scope of the approval. [782]

As Staff argues, DTE did not present the approval document and a review of Ms. Pfeuffer's testimony references "internal approval for detail engineering being received on May 11, 2022."[783] This is not an academic issue, since DTE did not address the open questions raised by the DGP in Schedule M1 and Schedule B5.4.8, both of which DTE purports to rely on. In its DGP, DTE projected a cost of $8.3 million for this project, and planned partial funding to come from other sources. In the informational chart at page 413 of Schedule M1, under "cost and scope of proposed NWA solution," it states: "Total cost: $8.3 million (DTEE + Developer + DOE Grant) plus additional private and public funding." This chart also includes, under "assumptions in analysis," the following statement: "In progress – details of the development and loading are still in early phases." In the text, at page 412 of Schedule M1, it also states:

> Funding for the project will come from a mix of DTEE, developer and DOE grants. A final decision on DOE funding is expected in late 2021. If DOE funding is not approved, the timing, scope and cost of the project may undergo significant revision.[784]

Schedule B5.4.8 states: "Estimated cost is approximately $12.0M based upon currently-known scope, including customer owned technologies."[785] Schedule B.5.4.8 also seems to limit project funding to DTE plus developer funding to "standard line extension and service CIAC policies," without explaining how such funds can contribute to the battery

[782] Staff brief, 47-49.
[783] 4 Tr 476.
[784] Exhibit A-23, Schedule M1, page 412.
[785] See Schedule B5.4.8, page 2.

pilot, and without explaining what happened to other potential sources of funding.[786] Instead, as item 3b, "availability of non-utility funding and whether any was pursued (such as state of federal funding opportunities) described," DTE states merely "no non-utility funding available." DTE's proposed timeline for the project calls for the customer to submit a formal request in 2022, with overhead circuit upgrades and URD construction expected in 2022, with the microgrid implementation planned for 2022-2026.[787] As Staff argues, and as MI MAUI and Ann Arbor seem to recognize, it is premature to include funding for this project in rates.

xiii. NWA: Small solar and storage testbed (B5.4, page 11, line 18)

Schedule B5.4, page 11, line 18, shows bridge and test year projected capital spending of $678,00 and $292,000, respectively. Ms. Pfeuffer did not specifically address this line item in her direct testimony and did not include it in the list of NWA pilots. Her Schedule B5.4.9 clearly considers this project a pilot, with the following stated goals and learnings:

> • The project will allow validation of behavior, interaction and compliance of the new features for smart inverters and act as a location to test new features and capabilities while also serving as a training platform for DTEE engineers, technicians and field employees[;]
>
> • Smart inverters are also capable of providing voltage and reactive support in either a passive or actively controlled mode. As the testing standards in IEEE 1547.1-2020 on smart inverters are finalized and interoperability standards such as IEEE2030.5 evolve and reach the market[;]
>
> • The lab facility will support several evaluations and will be continually updated to demonstrate technology interoperability and the processes and technologies to integrate customer resources into the grid.[788]

[786] See Schedule B5.4.8, page 2.
[787] See Schedule B5.4.8, page 3.
[788] Schedule B5.4.9, page 1.

The total cost is projected to be $1 million. The proposed timeline on page 3 of Schedule B5.4.9 shows engineering, design, and site preparation in 2021, engineering and construction in 2022, and "complete construction and start demonstrations" in 2023.

Dr. Wang testified that Staff recommends excluding the projected bridge and test year costs from rate base, explaining Staff's concerns with whether this investment is necessary.[789] She explained that DTE pays dues to EPRI, which has conducted research on smart inverters, citing Mr. Davis's testimony and Exhibit S-7.6. She testified that DTE previously conducted field experiments with smart inverters directly, beginning in 2011. She noted that the pilot would end in 2023, with DTE keeping installations for employee training and salvaging no longer useful equipment:

> Though Staff understands there may be potential benefits from training or technology demonstrations, the Company provided no assessment of the benefits and costs in comparison to a scenario where the solar and storage technologies are installed in the field and continue to function for the duration of their life. Staff suspects that the technologies will provide greater benefit to ratepayers and the resiliency of the electric grid by being utilized for their full lifetime rather than by serving as showpieces at a Company site or being tested until failure after the conclusion of the project in 2023, as currently planned.[790]

She recommended that DTE work toward an improved pilot design "with longer term benefits, generating more expansive and actionable learnings than can be gained from laboratory testing," also recommending collaboration with stakeholders.[791]

In rebuttal, Ms. Pfeuffer testified that it is not feasible to test all technologies in customer promises, citing safety issues, and the need for specific equipment, among

[789] 8 Tr 5177-5183.
[790] 8 Tr 5182.
[791] 8 Tr 5182-5183.

other impediments. She also provided an example to show that DTE cannot rely on manufacturer representation regarding equipment performance.[792]

DTE argues that it provided ample evidence in support of this project,[793] and cites Ms. Pfeuffer's rebuttal testimony.[794] Staff argues extensively in its brief that DTE failed to support the need for the project, citing limited information provided in Schedule M6 (pages 67-68) and in the DGP, Schedule M1, pages 414-415, and contending that DTE erroneously characterized Dr. Wang's testimony.

While this PFD acknowledges that DTE has not established a firm cost projection for this project, the project cost is minor and Ms. Pfeuffer's testimony is persuasive that there are benefits from the project. This PFD concludes the project funding should be included in rates.

xiv. NWA: EV charging demonstration (B5.4, page 11, line 19)

The EV charging demonstration is one of the pilots on Table 17 of Ms. Pfeuffer's direct testimony, with a stated objective to "develop control algorithm and conduct testing on an extreme fast charger and its interfaces as well as the development of cyber secure smart charge management capabilities for the Department of Energy."

Dr. Wang testified that labor costs represent approximately 40% of the total projected costs for this line item, and further testified that as a demonstration of a new technology, "there is limited understanding of what the project will require."[795] She recommended a reduction of 90% of the labor costs for the project due to the uncertainty, noting that the company may seek recovery of actual costs in a future rate

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[792] 4 Tr 776-484.
[793] DTE brief, 82.
[794] DTE brief, 85-87.
[795] 8 Tr 5215.

case.[796] Staff's adjustment reduces bridge period costs by $414,784 and test year costs by $442,800.

Mr. Richter objected to any funding for this project, as a general objection to DTE ownership of equipment types that are not necessary to the operation of the grid, including EV charging stations.[797] In rebuttal to Mr. Richter, Ms. Pfeuffer testified that the company is not proposing to own all EV charging devices, but instead "to study the impact of charging stations on the grid, including cyber security,"[798] citing Exhibit A-12, Schedule B5.4.10 pages 1 to 4 and Exhibit A-23, Schedule M1 pages 415-416.[799] GLREA does not address this pilot in its brief.

In its brief, Staff emphasizes a "high level of uncertainty" regarding the company labor required for this collaborative projected and urges the Commission to adopt its recommended labor reduction. DTE does not address Staff's adjustment directly, relying on its general objections to Staff's approach as stated in its reply brief:" The Company disagrees, and Staff's proposed disallowance should be rejected, for the same reasons the Company disagreed with other Staff disallowances based solely on the "high-level estimate" issues in this brief."[800] DTE did not establish the basis for its cost projection for this project, and thus this PFD finds Staff's recommendation should be adopted.

xv. Technology programs & NWA (B5.4, page 11, line 20)

Staff recommended excluding the $2,000 cost included in the bridge period for this line item. Citing Exhibit S-7.12, Dr. Wang testified that individual projects within this

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[796] 8 Tr 5216.
[797] 8 Tr 3252.
[798] 4 Tr 486.
[799] 4 Tr 486.
[800] DTE reply, 75.

program had been completed or transferred to separate projects in other line items.[801] On this basis, she recommended excluding the $2,000.

In rebuttal, Ms. Pfeuffer testified:

> The Company disagrees with this disallowance because Staff Witness Wang incorrectly associates these investments that were completed in the past with future investments. Investments in this category took place in 2021. The Company identified these projects as completed or moved into other categories starting in 2022. Forecasted investments in this project identified in Case No. U-20561 that Staff Witness Wang is proposing for disallowance were for 2021.[802]

In its brief, Staff disputes that it misunderstood the date of the spending at issue, noting that the company chose 2020 as the historical test year in this case, and Staff's recommended disallowance is for the 2021 bridge period.[803] DTE relies on Ms. Pfeuffer's rebuttal in its brief and reply brief, and further argues in its reply brief:

> Staff's Initial Brief, pp 53-54, responds that (1) the bridge period includes 2021, and (2) the programs and subprojects are either completed or located elsewhere. Staff's response misses the Company's point and neglects the temporal context: (1) 2021 is the past, and (2) Staff's reasoning concerns the present and future. There is a disconnect in Staff's reasoning that the Company fully explained, so Staff's proposed disallowance should be rejected.[804]

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

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[801] 8 Tr 5184.
[802] 4 Tr 466.
[803] Staff brief, 53-54.
[804] DTE reply, 58.

reconciliation, making it more difficult to evaluate both this line item and the other line items that now include expenditures for this project.

xvi. DERMS (B5.4, page 11, line 21)

DTE projected expenditures of $2.12 million for the bridge period and $2.54 million for the test year for this line item. Dr. Wang explained that Staff's recommended disallowance of $2.54 million for the projected test year reflects Staff's determination that this project is duplicative of the "DERMS implementation project" included in Schedule B5.7.4, line 27.[805] As shown on Exhibit S-7.42, Staff also recommends a 20% disallowance to the bridge year projection based on historical spending. In rebuttal, Ms. Pfeuffer agreed that the company's filing reflects the duplication of expense projections, but preferred the adjustment to be made to the IT expense projection rather than this line item.[806]

Staff continues to recommend excluding the expense from this category. In its brief, it argues that Ms. Pfeuffer erroneously claimed Staff proposed disallowing the expense in both categories, and notes that it has an additional disallowance to this line item as it appears in the IT capital expense schedule that is not duplicative of Staff's adjustment to this line.[807] In its brief, DTE removed the duplicative expense from its revised rate deficiency calculation. This PFD considers this matter resolved and the remaining dispute regarding DERMS, which relates to capitalization, will be addressed in the IT capital subsection of this PFD, because Staff's recommended disallowance on this item ultimately relates to its analysis of IT capital expenditures.

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[805] 8 Tr 5216.
[806] 4 Tr 486-487.
[807] Staff brief, 77-78.

xvii. Work management & scheduling upgrades (B5.4, page 11, line 24)

As shown on Schedule B5.4, page 11, DTE projected bridge and test year expenditures for this line item of $1.25 million and $9.34 million, respectively. Dr. Wang identified this project as an example of the t-shirt estimation method Staff finds insufficiently reliable to include in rate base.[808] As noted above, Ms. Pfeuffer objected to Staff's rejection of its t-shirt estimation method.[809] For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

xviii. Asset management upgrades (B5.4, page 11, line 26)

As shown on Schedule B5.4, page 11, DTE projected bridge and test year expenditures for this line item of $1.08 million and $1.95 million, respectively. Dr. Wang identified this project as an example of the t-shirt estimation method Staff finds insufficiently reliable to include in rate base.[810] As noted above, Ms. Pfeuffer objected to Staff's rejection of its t-shirt estimation method.[811] For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

xix. Load forecasting & analytics (B5.4, page 11, line 27)

As shown on Schedule B5.4, page 11, DTE projected bridge and test year expenditures for this line item of $3.3 million and $3.13 million, respectively. Dr. Wang identified this project as an example of the t-shirt estimation method Staff finds insufficiently reliable to include in rate base.[812] As noted above, Ms. Pfeuffer objected to

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[808] 8 Tr 5187-5188.
[809] 4 Tr 464-465.
[810] 8 Tr 5187-5188.
[811] 4 Tr 464-465.
[812] 8 Tr 5187-5188.

Staff's rejection of its t-shirt estimation method.[813] For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

xx. Interconnection process enablement (B5.4, page 11, line 28)

Schedule B5.4, page 11, includes bridge and test year projections of $3.14 million and $3.64 million, respectively. Citing Exhibit S-7.37, Dr. Wang explained DTE's current handling of interconnection requests:

> The Company currently responds to interconnection request within the timelines set forth in regulations. Depending on the project, interconnection requests range from a few days to the maximum allowed. In 2021, the Company only had six large projects requiring interconnection studies. The average study duration for these was 39 days, with a minimum of 29 days and a maximum of 59 days. Each study is dependent on the project scope, scale, and specific requirements.[814]

Dr. Wang also cited the ADMS NWS program, explaining that it would also reduce interconnection time, at a lower cost:

> Staff supports the Company's development of customer tools that support more rapid interconnection processes. Assisting customers to rapidly interconnect while maintaining the safety, reliability, and resiliency of the grid will be increasingly important in a future with more DERs. However, it is unclear why the creation of a smoother customer experience with the interconnection process will cost more than the ADMS: NMS upgrades that provides data to expedite the actual interconnection process. Given that the projected costs in the Interconnection Process Enablement project are high-level costs, there is likely a significant uncertainty and actual costs may not materialize.[815]

Based on uncertainty whether the projected amounts would be spent, she recommended that the Commission reduce the projected expenditures by 75%.[816] As

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[813] 4 Tr 464-465.
[814] 8 Tr 5217.
[815] 8 Tr 5219.
[816] 8 Tr 5219.

shown in Exhibit S-7.42, Staff also made a small adjustment to the remaining costs in this category to conform the projection to the 5.17% "other cost" estimate.

In its brief, Staff argues that its recommendation was unrebutted and should be adopted. DTE's objection to Staff's adjustment for the overhead or "other" cost component is discussed above. Consistent with that discussion, this PFD finds that Staff's adjustment should be adopted.

xxi. Hosting capacity enablement (B5.4, page 11, line 29)

Dr. Wang identified this project as an example of the t-shirt estimation method Staff finds insufficiently reliable to include in rate base.[817] As noted above, Ms. Pfeuffer objected to Staff's rejection of its t-shirt estimation method.[818] For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

xxii. AMI: meter communications upgrade (B5.4, page 11, line 31)

Mr. P. Smith presented testimony in support of the company's historical and projected expenditures for AMI meter communications upgrades.[819]

Ms. Rogers addressed this element of the company's cost projections. Regarding the company's request to recover actual historical expenditures of $0.6 million above amounts approved in Case No. U-20561, Ms. Rogers recommended against recovery. Noting that the Commission had denied the company's request to include this cost in projected rate base in Case No. U-20561, she testified:

> While Staff is sympathetic to the customers who live in areas where vegetation growth affects meter performance from around May 15-October 15, the Company is unable to provide evidence that these customers are dissatisfied with their service. Staff requested the number of complaints

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[817] 8 Tr 5187-5188.
[818] 4 Tr 464-465.
[819] 7 Tr 1904-1912.

> received annually from these perennially-affected customers and the number of power outages experienced by these customers for the past 5 years, with information regarding the outages. The Company responded that they do not have data that correlates to customer complaints due to decreased meter read rates from vegetation growth. Furthermore, the Company states their single day performance of AMI reporting reliability in 2021 was 99.51%. The annual performance rate was 99.69% during months not impacted by vegetation and 99.26% during the months impacted by vegetation. The lowest annual performance rate, 99.26%, was during months impacted by vegetation and is still significantly above the current 85% acceptable meter reading service quality level of performance. The 99.26% performance rate is even significantly above the revised meter reading service quality standard performance rate of 95%, approved by the Commission for submission to the Legislative Service Bureau and the Michigan Office of Administrative Hearings and Rules for approval. Subsequently, Staff believes the $0.6M was unnecessarily spent.[820]

She cited data Exhibits S-12.13 and S-12.14 in support of her testimony.

Regarding the company's request to recover $3.9 million in 2020 expenditures for the installation of advanced power quality meters for its largest commercial and industrial customers, Ms. Rogers again noted that in Case No. U-20561, the Commission declined to include projected costs for these meters in rate base, finding that the company needed to better define the current status of systematic power quality.[821] Ms. Rogers explained Staff's position that the company has not adequately justified installation of these meters:

> While the Company lists possible benefits, it has not shown that those benefits have been realized by itself or to its customers. Company witness Smith's testimony states that the Company cannot quantify the benefits until it can detect and measure actual electric disturbances and response to them when failures occur. Until such benefit scan be quantified or shown by actual proven evidence, Staff believes the historic and projected capital expenditures related to the advanced power qualify meters should be disallowed. [822]

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[820] 8 Tr 5366-5367.
[821] 8 Tr 5368.
[822] 8 Tr 5367-5368.

Finally, Ms. Rogers addressed the company's projected expenditures for this line item, explaining that Staff recommends a disallowance because Staff cannot determine the specific projects underlying the projections. Based on Exhibit A-23, Schedule M6, page 122 and information in Staff Exhibit S-12.14, page 8, it appears the expenditures relate to the large commercial and industrial meter upgrade, which Staff recommended be rejected until the company provides additional information as discussed above.

In rebuttal, Mr. P. Smith responded to both elements of Staff's adjustment. Regarding the residential meter read rate, Mr. P. Smith testified that for 13,000 customers affected by the seasonal vegetation, the meter read rate was essentially zero for six months of the year.[823] He also testified that the $0.6 million in dispute is not related to the disallowances the Commission adopted in Case No. U-20561.[824] Regarding the advanced power quality meters for industrial customers, he testified that DTE disputes that the meters are useful primarily for forensic analysis following a disturbance:

> The Company believes that the investment in PQ meters for our 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. It is crucial that disturbances are detected immediately, and relevant data is available to inform operational personnel and/or customers if immediate, mitigating action is needed.[825]

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[823] 7 Tr 1915-1916.
[824] 7 Tr 1917.
[825] 7 Tr 1917.

After asserting that there were efficiencies in installing the meters when the 3G meters needed to be replaced with 4G meters, as an alternative, Mr. P. Smith requested $698,000 to fund replacement of 3G meters with non-power-quality 4G meters.[826]

DTE's brief tracks Mr. P. Smith's testimony and rebuttal testimony on this expense.[827] Regarding the power quality meters, DTE argues:

> 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).[828]

It does renew Mr. P. Smith's request for the alternative funding for non-power quality meters.

In its brief, Staff revised its position and reduced its projected disallowance to $3.9 million in the historical year, $1.03 million in the bridge period, and $0.5 million in the test year. Staff no longer objects to $0.6 million to remediate residential AMI meters impacted by seasonal vegetation, based on Mr. P. Smith's rebuttal testimony indicating that the meter read for affected customers is near zero during the growing season.[829] The remainder of Staff's adjustment related to Staff's objection to the cost of advanced power quality meters for commercial and industrial customers. Staff maintained its

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[826] 7 Tr 1918.
[827] DTE brief, 108-111.
[828] DTE brief, 110.
[829] Staff brief, 88-89.

recommended disallowance for the advanced power quality meters, but agreed to the addition $698,000 in bridge-period funding for non-power-quality 4G meters.[830]

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

xxiii. Automation configuration and test record database (B5.4, page 11, line 34)

Dr. Wang explained Staff's recommended disallowance of costs for this project, characterizing the company's cost estimate as "high level." As an example of Staff's concern with the company's capitalization of software costs that should be expensed, she further explained that the company's project scope includes evaluating software options, which she identified as preliminary stage activities that should be expensed. Additionally, she testified that the data conversion costs included in the project scope should also not be capitalized unless allowed by Commission order.[831]

As noted above, Ms. Pfeuffer responded to Staff's concerns regarding capitalization in rebuttal, asserting that the projects "were not presented as being in the preliminary state," and company would not capitalize data conversion or data cleanup costs.[832] As discussed above, this PFD finds that the company has failed to establish that the project is not in a preliminary stage, or that it identified O&M costs associated with this project that were already capitalized. Staff's adjustment is reasonable and should be adopted.

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[830] Staff brief, 90.
[831] 8 Tr 5188-5193.
[832] 4 Tr 452.

xxiv. Grid edge insights and new technology (B5.4, page 11, line 35)

Staff recommends a disallowance of $1.99 million for the bridge period and $1.78 million for the test year. Dr. Wang testified that DTE expects to deploy the platform at various pilot projects, many of which are not complete or have not received internal approval. She also identified what Staff considers a discrepancy in project scope between the company's discovery response in Exhibit S-7.12, page 3 and page 136 of Exhibit A-23, Schedule M6.[833]

In rebuttal, Ms. Pfeuffer disputed that the company had provided conflicting information regarding the project scope.[834] She testified:

> On page 21 lines 20-21 continued on page 22 lines 1-4, Staff Witness Wang claims '[t]he description of the Grid Edge Insights & New Technology project scope in discovery focuses on a more general investigation, evaluation, and procurement of new grid hardware for DTE Electric." In discovery response STDE 15.66c, shown in Staff Exhibit S-7.12 page 3 of 5, the Company states that "New Technology Pilots project is used to investigate, evaluate and procure initial instances of new grid hardware for DTE Electric." The referenced scope was for New Technology Pilots, which was part of the Technology Programs & NWA project line item in past cases. In STDE-15.66c, the Company does note that should there be any such new technology pilots, those costs will be shown in the new Grid Edge Insights & New Technology line item, but the Company in no way implied this changed the scope of work currently proposed in Grid Edge Insights & New Technology.[835]

She also cited DTE's discovery response in Exhibit S-7.13, pages 1-2, contending that DTE clarified the scope of the project "by identifying some of the specific scope of work," and that Dr. Wang ignored this confirmation.[836]

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[833] 8 Tr 5185-5187.
[834] 4 Tr 466-468.
[835] 4 Tr 467.
[836] 4 Tr 467-468.

In its briefs, DTE relies on Ms. Pfeuffer's rebuttal testimony.[837] Staff maintains that the company has not established that the scope of the project will be limited to cybersecure control and communications schemes for DERs and microgrids, but will be much more general.[838] This PFD concludes that DTE has not changed the scope of the project, and in the absence of other objections, its cost projection should be adopted.

xxv. Other modernize grid management (B5.4, page 11, line 37)

DTE projected bridge period spending of $364,000 and test year spending of $1.05 million. Dr. Wang identified this project as an example of the t-shirt estimation method Staff finds insufficiently reliable to include in rate base.[839] As noted above, Ms. Pfeuffer objected to Staff's rejection of its t-shirt estimation method.[840] For the reasons discussed above, this PFD finds DTE's t-shirt-sizing estimation method is unreliable and Staff's recommendation is reasonable.

xxvi. Operational technology and error free communication (B5.4, page 11, line 39)

DTE projects bridge period spending of $12.6 million for this line item, with an additional $0.33 million in the test year. As with the automation configuration and test record database expense projection in line 34, discussed above, Staff's recommended disallowance of the bridge and test year expense projections for this line item is based on its concerns with the company's capitalization of certain software costs.[841] Dr. Wang testified that like data conversions, costs for system upgrades and enhancements should be expensed unless they had significant additional functionality and reflect a new

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[837] DTE brief, 77; DTE reply, 58-59.
[838] Staff brief, 54-56.
[839] 8 Tr 5187-5188.
[840] 4 Tr 464-465.
[841] 8 Tr 5193-5196.

software design or design change, with a $10,000 threshold met. Dr. Wang testified that Staff is perplexed by the overall project cost of $12.9 million for a project limited to manipulating existing data and generating new reports.

As discussed above, Ms. Pfeuffer disputed that the projects are preliminary in nature. She further disputed that this project should be expensed rather than capitalized, characterizing it as major project, beyond data collection or revised reporting:

> The EFC project is a significant project that fundamentally changes the underlying process by which we communicate with our customers, and in scope goes well beyond simply resulting in new reports and facilitating data retrieval. Over the course of the frequent outages in the summer of 2021 and in previous outages, customers have frequently identified that they want accurate and consistent communication about the status of their outages. The Company has listened to its customers, and the EFC project represents a significant improvement, and a strategic shift in how we are communicating with our customers about their outages. Our current OMS (Outage Management System) has limited ability to leverage AMI data in real time. With EFC, the Company is leveraging our AMI information as it becomes immediately available to determine restoration status of its customers. The Company is also combining our AMI data with the equipment hierarchy of the distribution network to understand and locate trouble behind trouble customers - meaning customers that would have previously been believed to have been restored, but in fact were not. In the past, those customers would have to call or report their outage again using Company channels in order for the Company to know they still did not have power. Additionally, the Company is pushing this new information about outages into its customer systems so customers know that 1) the Company is aware that they don't have power; 2) the Company believes they may have lost power; 3) the Company can confirm their power has been restored.[842]

In its brief, DTE relies on Ms. Pfeuffer's explanation, discussed above.[843] Staff's brief renews its concerns with the capitalization of this project, citing three criteria that

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[842] 4 Tr 453-454.
[843] DTE brief, 80-81.

must be met and disputing that this project meets the first criterion, that the expenditures result in significant new functionality beyond new reports.[844] Staff argues:

> Staff asserts the Company being able to tell customers whether the Company definitively knows whether customers have power or not does not constitute significant additional functionality. This is especially true when the Company is developing new reports and dashboards that process currently available AMI data. Staff does not believe all three criteria necessary for capitalizing system upgrades or enhancements, such as those for new reports, are met by this project. As such, the related costs should be categorized as O&M costs.[845]

Staff also finds the cost estimate excessive, citing Dr. Wang's testimony and Schedule M6, pages 151-154. In its reply brief, DTE summarizes Ms. Pfeuffer's rebuttal and contends that Staff's concern whether significant additional functionality is added is unfounded and contrary to the record.[846]

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

[844] Staff brief, 61-62.
[845] Staff brief, 62.
[846] DTE reply, 64.

44.[847] Likewise, DTE has not explained how this project relates to all its other OMS expenses, including its difficulty with the OMS component of ADMS as discussed above.

D. Community Lighting (Exhibit A-12, Schedule B5.5)

DTE's projected capital expenditures for its lighting program are shown in Schedule B5.5 of Exhibit A-12. Mr. Bellini testified in support of these expenditures, which include a 2020 capital expense of $15.2 million, and projections of $29.6 million for the bridge period and $16.7 million for the test year. There are two subcategories of expenditures on Schedule B5.5, "new installations and replacements," and "post charge." The post charge reflects a funding option for communities to fund capital projects at DTE's weighted cost of capital in lieu of a contribution in aid of construction adopted in Case No. U-20162. As part of his overview of DTE's lighting assets, Mr. Bellini presented a charge showing lighting assets by ownership (DTE or municipal), rate type, and number of assets.

Mr. Bellini testified that the 2020 capital expenditures included $4.7 million for outage restoration, $0.8 million for post replacement, and the balance for new business.[848] He testified that the projections for the bridge and test year also include outage restoration, port replacement, planned conversions, new business, "capital support staff," and targeted infrastructure upgrades such as underground cable

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[847] Also see Exhibit A-24, Schedule N1.333 referenced on Schedule B5.7.2, line 7, customer journey transformation external system support ("This initiative contains workstreams working in to refine and deliver enhancements required for Customer Outage Experience."); also see Exhibit A-24, Schedule N1.65 referenced on Schedule B5.7.4, line 3, distribution operations application health ("F002 - Add new functionality that will improve the customer closed loop process. This process sends out notifications and improves communication when customer's outage situation changes. This process helps to keep the customer informed from time outage is reported until the job is completed.")
[848] 7 Tr 1720.

replacement.[849] Mr. Bellini presented additional detail regarding the company's outage restoration in Schedule O2 of Exhibit A-25. He testified that outage restoration also includes conversion of failed mercy lamps to LED. Mr. Bellini described efforts the company is undertaking to reduce outage restoration expense. He also reviewed the company's contributions-in-aid-of-construction (CAIC) policy.[850] He testified that DTE does not include a separate line-item for CAIC because such contributions are subtracted from the total capital cost and only the net capital outlay is recorded as a capital expense.

1. Staff

Dr. Wang explained Staff's recommended reductions to the company's capital cost projections.[851] She reviewed an updated statement of DTE's 2021 capital expenditures, shown in Exhibit S-7.1, and recommended a reduction to bridge and test year expenditures to reflect the same overprojection she observed for 2021, as shown in Exhibit S-7.2.[852] Staff's recommended a reduction in the 22-month bridge period of $1.85 million and a reduction in the projected test year of $1.15 million.[853] In rebuttal, Mr. Bellini objected to basing a reduction in its 2022 and 2023 projections on its 2021 overprojection. He presented Schedule Y6 of Exhibit A-34 to show "a more detailed presentation of capital spend than does the consolidated view that Staff Witness Wang used."[854] He testified that looking at historical spending does not account for the slowdown in new business he attributes to COVID and related disruptions in crew

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[849] 7 Tr 1720-1721.
[850] 7 Tr 1724.
[851] 8 Tr 5171-5174.
[852] Staff treats DTE's 2021 spending as confidential, without indicating why.
[853] 8 Tr 5173.
[854] 7 Tr 1774.

availability, a high-impact storm season that reassigned crews to storm restoration work, and the impact of the company's night patrol program, which he believes will lead to increased capital replacements.[855] He also testified that the company's cable replacement program is new and not reflected in historical spending.

In its briefs, DTE relies on Mr. Bellini's rebuttal. Staff addressed Mr. Bellini's rebuttal testimony by explaining that its disallowance was based on the inaccuracy in the company's 2021 forecast, not merely the level of historical spending:

> Staff's recommended disallowance attempts to address the Company's inaccuracy in its Community Lighting cost forecasts. Though Company witness Bellini discusses various reasons and considerations included in the Company's projected Community Lighting costs in rebuttal, these are not pertinent to Staff's recommended disallowance. The Company's projected/forecasted spending for 2021 was likely well-reasoned and supported. However, the Company failed to spend the projected/forecasted amount and spent less in 2021. The data shows the Company's cost forecasts for the Community Lighting project was not accurate for 2021. Since the Company has made no mention or assurances regarding changes in its forecasting methodology that would increase its forecasted cost accuracy, one cannot assume that its cost forecasts in the instant case will be any more accurate.[856]

In its reply brief, DTE again reviews Mr. Bellini's rebuttal testimony, and argues:

> Staff's reasoning is inaccurate because 2021 is historical. Staff similarly misses the mark in suggesting dismissal of the Company's evidence as somehow "not pertinent to Staff's recommended disallowance." (Id, p 92). Instead, the Company's evidence directly refutes Staff's recommended disallowance, so it is highly "pertinent." Finally, Staff suggests that "one cannot assume that [the Company's] forecasts in this case will be any more accurate" (Id, p 92).[857]

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[855] 7 Tr 1774-1775.
[856] Staff brief, 92.
[857] DTE reply, 87

It argues that by not accepting Mr. Bellini's rebuttal regarding storms and the cable replacement program, Staff is ignoring record evidence and engaging in speculation.[858]

At the outset, it appears that DTE misunderstands Staff's analysis. Staff did not look at DTE's 2021 forecast from a prior rate case, but looked at the forecast it submitted in this case, in January of 2022, after the storms of 2021. DTE failed to show any logical relationship between its January 2022 overprojection of 2021 spending and the historical events of 2021. In addition, while DTE has indicated it intends to pursue a new cable replacement program, it did not separately forecast those expenses in its evidentiary presentation in this case. As noted above, Mr. Bellini also discussed efforts the company is undertaking to reduce its outage restoration expense, although it also has not separately forecast the impact of those activities. In the absence of greater detail presented by DTE, Staff's analysis appears reasonable.

2. MI MAUI

Mr. Bunch took issue with several cost elements in DTE's lighting projections. Regarding capital costs, he objected to DTE's LED lighting choices as in excess of manufacturer's recommended wattage for conversions, and above the wattage used by Consumers Energy.[859] He presented cost comparisons for a 58W LED versus the 40W LED Consumers Energy uses, including greater operating costs for the higher wattage. He also objected that DTE purported to rely on its own internal analysis of the appropriate wattage to use, but would not provide the company's analysis, citing Exhibits MAUI-17 and MAUI-18.[860] He recommended that the Commission require DTE

[858] DTE reply, 87-88.
[859] 8 Tr 3467-3471.
[860] 8 Tr 3468-3469.

to follow industry best practices,[861] and also objected to the wastefulness of the higher wattage:

> The Commission should be mindful that excessively costly LED luminaires create more light than is needed for a given application, leading to light trespass and light pollution; and use more electricity than necessary, undermining energy waste reduction and climate goals without creating any balancing benefit. Delivering more light to the customer than roadway lighting standards specify is not a benefit: too much light is a form of pollution and has no consistent social benefits. Therefore, focusing on cost, which is well within the Commission's grasp, also supports other important public policy objectives.[862]

Mr. Bunch also raised an objection to DTE's preemptive replacement or "re-lamping" policy, questioning whether it should be permitted for HID lamps, for which he believes conversion to LED should be the goal. He testified that DTE also had not supported that this policy for HPS lamps, stating that outages have not decreased. He referred to DTE claims that its outage management system cannot capture luminaire, installation, or wiring type, and concluded that DTE's choice of lamps to replace has a high false negative rate.[863] Mr. Bunch believes network controls are the best solution to promote reliability. That recommendation along with other programmatic recommendations are discussed below.

Mr. Bunch also took issue with the 2020 historical plant balances, questioning why the plant balances increased for lighting types when DTE has been projecting the counts for those lighting types to go down. His concerns with the allocation of projected capital expenditures for the bridge period and test year are discussed in connection with rate design, below.

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[861] 8 Tr 3470.
[862] 8 Tr 3471.
[863] 8 Tr 3458-460.

In rebuttal, Mr. Bellini disputed that the company's plant balances were inaccurate or unreliable. He testified to reasons why the luminaire counts would not move in the same direction as the plant balances, contending that older and likely lower-cost lights were replaced with more expensive ones in current dollars, and that DTE is still replacing HID as a viable lamp technology.[864] He also asserted that company's projected capital expenditures are accurate and necessary to support outage restoration, new business installation, and planned cable replacement. He testified that no audit was needed.

Mr. Bellini testified that capital spending is booked by luminaire type, and contended that Mr. Bunch had arrived at the wrong conclusion from DTE's discovery response, which he included in the record as Schedule Y1 of Exhibit A-34. He testified that 2019 outage costs were previously booked incorrectly, and this response shared "what they would have looked like if followed same percentage allocation among 4 subaccounts for 2020."[865]

Mr. Bellini addressed the company's outage performance, contending that Mr. Bunch's compilation is out of context. He contended that outage restoration costs may increase in the short term due to outages identified by the night patrols, and testified that there was a decrease in customer-reported outages from 2019-2021.[866] He interpreted Mr. Bunch's testimony as supportive of additional night patrols.[867]

Mr. Bellini addressed group re-lamping, contending Mr. Bunch mischaracterizes the intent of the company's program. He testified that DTE "stands behind its study

[864] 7 Tr 1745-1746.
[865] 7 Tr 1748.
[866]7 Tr 1749-1751.
[867] 7 Tr 1753.

performed in 2011," contending that this study showed that re-lamping reduced outages in the test area. He likened the re-lamping to getting an oil change for your car, testifying that there is a 60-70% lamp failure rate after 9 years. He concluded that it is reasonable and prudent to "continue with the current program cadence."[868] Regarding HPS lighting, he testified this type of lighting is still a Commission-approved product and DTE needs to service all offerings. He considered that terminating the re-lamping program would be akin to rendering the HPS lighting obsolete.[869] Although not a lawyer, he testified that Mr. Bunch is asking DTE to act "contrary to existing legislation and tariff" to the detriment of municipalities who have chosen to use HPS luminaires. He asserted that discontinuing the re-lamping would lead to an increase in outage events.

Mr. Bellini also disputed that DTE was choosing to use LEDs with a higher than needed wattage, citing an example of a 400W HPS cobrahead replacement that Consumers Energy also uses. Then he testified that DTE spaces poles farther out, using with taller poles to meet light level targets, and does the same with smaller wattages. He clarified that he was not contending that Consumers Energy was wrong, but that each utility should design lighting for the unique roadways it serves.[870]

In its brief, MI MAUI and Ann Arbor argue that DTE did not establish the validity of its plant balances, contending that Mr. Bellini did not provide data to support his claim that new HIDs are significantly more expense than older ones. It contends there is an HID count mismatch, that overhead lighting is more likely to be replaced with LEDs, in which case there would be no addition to HID plant balances. MI MAUI and Ann Arbor

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[868] 7 Tr 1959.
[869] 7 Tr 1759.
[870] 7 Tr 1760-1762.

further argue that decommissioned luminaires should be removed from plant-in-service at a fleet average, given that DTE does not know the vintage of each luminaire removed, contending that assigning an older 2005 value is arbitrary.[871]

MI MAUI and Ann Arbor also argue that the Commission should stop funding the re-lamping of HIDs, since DTE cannot provide evidence that it prevents outages, calling its usefulness into question.[872] MI MAUI and Ann Arbor dispute that re-lamping is justified based on Mr. Bellini's testimony regarding the manufacturer's projected service life, contending that outages have increased since DTE began this program and thus, that DTE cannot predict the lamps that are nearing the end of their service lives. MI MAUI and Ann Arbor also cite Exhibit MAUI-44.

DTE relies on Mr. Bellini's testimony in its brief, focusing primarily on Mr. Bunch's testimony regarding networked lighting controls and removal costs.[873] In its brief, DTE addresses its re-lamping program as an O&M issue.[874] It similarly addressed the LED wattage choice as an LED issue, relying on Mr. Bellini's testimony in arguing: "To provide value for customers, the Company's standard practice is [to] place high-lumen-output luminaires on taller streetlight poles that are spaced farther apart, which lowers costs by using fewer poles and luminaries to achieve the desired and ANSI/IES compliance light levels."[875]

This PFD finds that the record does not support adjusting DTE's capital balances. MI MAUI and Ann Arbor raise a legitimate concern with DTE's wattage

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[871] MI MAUI brief, 56-57.
[872] MI MAUI brief, 60-61.
[873] DTE brief, 112-113.
[874] DTE brief, 191-192.
[875] DTE brief, 192.

choices for conversions; DTE should be put on notice that it will need to justify those choices in a future rate case. DTE's arguments about pole height are factual questions subject to verification; if DTE is installing LED bulbs in poles that are not higher and less-densely spaced, it should look for the lower-cost, less-energy-intensive bulbs. DTE may face a disallowance if its representations are not accurate.

Regarding the group re-lamping concerns raised by MI MAUI and Ann Arbor, their concerns focus both on the efficacy of DTE's group re-lamping generally as well as on the potential inefficiency of replacing the older bulbs rather than converting them to LED. Regarding the first concern, this PFD recommends that the Commission require an updated analysis of the efficacy of the policy from DTE, including a review of the accuracy of its records for those replacements and a more detailed review of the failure rates of these bulbs. Regarding the second concern, this PFD recommends that the Commission require DTE to provide a net present value revenue requirement analysis (NPVRR) of the alternative replacements so the Commission can make a determination whether DTE's current re-lamping policies should be continued.

E. Demand Response (Exhibit A-12, Schedule B5.6)

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

F. Information Technology (IT) (Schedule B5.7)

As shown in Exhibit A-12, Schedule B5.7, DTE breaks its IT capital expense data into categories by portfolio and by major category. In the discussion that follows, the portfolio categories are used, with detail in Schedules B5.7.1 through B5.7.9. The categories include: corporate applications; customer service (sustainment and return to health); customer service (strategic enhancements and compliance); plant and field; information technology for IT; information protection security; infrastructure operations; enterprise data analytics; and innovations. Since Case No. U-20561, DTE has modified its categorization of IT costs, splitting the customer category into two categories as noted, and adding the innovations category. Mr. Sharma and Ms. Pizzuti testified in support of the company's capital expense projections in these categories. Staff witnesses Ms. Rogers, Ms. Armstrong, and Dr. Wang testified to Staff's recommended reductions. Staff's recommendations included both broad adjustments as well as more specific adjustments; Attorney General witness Mr. Coppola made recommendations focused on specific line items. In the discussion that follows, following a review of the company's evidentiary presentation relative to the Commission's directives, this PFD discusses Staff's general recommendations before turning to specific line items.

1. Compliance with IT requirements

Given the history of rate case disputes regarding DTE's IT projections, it is appropriate to review the instructions the Commission has provided regarding IT capital expenses. In DTE Electric's last rate case, U-20561, the Commission began its analysis of IT Capital Expenditures with a reminder of its previous directions regarding IT issues.

The Commission quoted Part III of the Rate Case Filing Requirements, which requires a utility to provide the following specific IT-related information in rate case filings:

> Provide spreadsheet/exhibit that includes all of the following information for the highest cost top 25 IT and OT [operational technology] projects in the test year.
>
> a. Project description and functionality of the system with all acronyms defined.
> b. Project timelines and spending plans.
> c. Project benefits, both in dollars and intangible.
> d. Project timeline including expected implementation date.
> e. A description of alternatives considered, and rational behind decision.
> f. Cost benefit ratio (if applicable).
> g. Project business case showing date of Board Approval, and approved project amount for Each Individual Project.
> h. Percentage of total budget that the top 25 projects represents, and total number of projects that fall outside of the top 25.[876]

The Commission continued by noting that in Case No. U-20162, DTE Electric's then-previous rate case, the Commission imposed additional, more detailed requirements for IT capital expenditures:

> A. Future IT project-level detail will include a breakdown of both the O&M and capital costs. O&M costs will be broken down into two or three sub-categories.
>
> B. For each IT project with a value threshold of $500,000 or more the company will submit a project approval document after the project preliminary analysis phase that includes:
>
> 1. A brief synopsis describing the project.
> 2. The project approval date.
> 3. The incurred O&M expenditures to date.
> 4. The total project estimated O&M and capital cost through project implementation.
> 5. Any necessary approvals by the company's management with appropriate expenditure approval authorization (per documented company policy).

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[876] May 8, 2020 order, Case No. U-200561, pages 122-123, quoting Rate Case Filing Requirements, adopted in the Commission's July 31, 2017 order, Case No. U-18238, filing #U-18238-0037.

> 6. Any approved change management documentation if the total project estimate grows by greater than 10% or $500,000 (whichever is greater).
> 7. For IT projects over $500,000, the company will include as an exhibit a copy of the written, PowerPoint, or other media presentation that the company's technical staff used to present the project justification and alternatives considered by company senior management.
> 8. Analysis that shows the company considered cloud computing alternatives in IT project expense requests over $100,000 excluding cyber security or transmission control IT projects.
> 9. The company will provide a breakdown of any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount with an explanation of why the project was not completed or why it was off budget, only for projects that meet the $500,000 threshold and where additional recovery is being sought in the relevant rate case.[877]

After summarizing these requirements, the Commission noted that the ALJ's PFD critiqued DTE Electric's IT-related documentation for failing to address several of the requirements including failing to quantify benefits, report a cost-benefit analysis, or identify alternatives.[878] The Commission analyzed a myriad of IT-related proposals and repeatedly agreed with the PFD's recommendations to disallow capital expenditures on most of the IT proposals because DTE Electric did not provide sufficient documentation and explanation to prove that they were reasonable and prudent.[879]

The Commission addressed the issue by acknowledging that "IT capital & O&M spending . . . has been challenging for the Commission to review for reasonableness and prudence. Detailed support for individual projects has been lacking despite guidance provided by the Commission."[880] After summarizing past complications

[877] May 8, 2020 order, Case No. U-20561, p 123, quoting May 2, 2019 order, Case No. U-20162, pp 44-45.
[878] May 8, 2020 order, Case No. U-20561, p 124.
[879] May 8, 2020 order, Case No. U-20561, pp 124-151.
[880] May 8, 2020 order, Case No. U-20561, p 151.

involving the evaluation of IT spending, the Commission concluded "[w]e appear to be stuck in a vicious cycle on IT issues in rate cases."[881]

The Commission made future recommendations and sought to provide guidance by offering what it saw as "two paths forward."[882] In the first path, the Commission proposed that the Company could invest in new IT projects and support its decisions after the fact in rate cases using actual costs; the Commission acknowledged that this path involved regulatory lag and the potential for write-offs if expenditures were later deemed imprudent.[883] In the second path, the Commission proposed that the Company could work with the Commission, Staff, and stakeholders on a comprehensive IT plan to strategically and holistically address the Company's IT needs; the Commission specified that this path was modeled on the Company's distribution planning effort.[884] The Commission specified that the Company could meet with Staff to start such a plan if it so desired, the plan would not be expected to be concluded before future rate cases, and cost approvals would not be provided.[885] The Commission concluded that "[i]n the meantime, the Commission directs DTE Electric to follow the Commission's prior guidance along with the reporting recommended by Staff in this proceeding to support IT expenditures."[886]

The additional reporting that was recommended by Staff—and approved by the Commission—was proposed in Staff's initial brief. It consisted of two additional reporting requirements: (1) the Company should detail the projected benefit of each program in

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[881] May 8, 2020 order, Case No. U-20561, p 152.
[882] May 8, 2020 order, Case No. U-20561, p 152.
[883] May 8, 2020 order, Case No. U-20561, p 152.
[884] May 8, 2020 order, Case No. U-20561, pp 152-153.
[885] May 8, 2020 order, Case No. U-20561, pp 152-153.
[886] May 8, 2020 order, Case No. U-20561, pp 152-153.

monetary terms, and (2) the Company should provide evidence of prudent and reasonable spending for historic and year-to-date spending for any business case where the program objectives are determined as each initiative is approved.[887]

Mr. Sharma explained the documents the company provided in this case in support of its projected IT capital expenditures as follows:

> To address the feedback Staff and Commission provided in Case No. U-20561 specific to 2019 Rate Case exhibits and workpapers, I have added a new exhibit (Exhibit A-24 Schedule N3 Revised) that contains project details around investment scope, cost estimates, benefits, considered alternatives, and cloud strategy. 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.[888]

After reviewing these documents in the course of evaluating the specific arguments of the parties, this PFD notes that the documents DTE provided for the record in this case do not appear to comply with the Commission's instructions, which frustrates review of both the reasonableness and prudence of the company's proposed spending and the likelihood money will be spent as projected, and evinces the vicious cycle the Commission described. For example, neither the N1 schedules nor Schedule N3 contains a quantification of benefits for the projects listed,[889] a timeline showing the project steps or associated spending plans, the project approval date or any necessary

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[887] MPSC Staff Initial Brief, Case No. U-20561, docket # U-20561-0440, page 124.
[888] 7 Tr 1927.
[889] As discussed below, DTE explains that it uses a project prioritization process in lieu of a traditional benefit cost analysis.

approvals by management,[890] or previous O&M spending. The Schedule N1 business case forms are not dated, and no changes in spending plans are reflected on those forms, although DTE acknowledges many changes in projected spending, as shown in Schedules GG3 and GG4 of Exhibit A-42, and as also discussed by Mr. Sharma and Ms. Pizzuti in their testimony. Mr. Sharma characterized Schedule N3 as a new exhibit "that contains project details around investment scope, cost estimates, benefits, considered alternatives, and cloud strategy."[891] This exhibit, however, has little informational content. The text in Schedule N3 as "project synopsis" appears to be essentially a repeat of the testimony Mr. Sharma or Ms. Pizzuti offered regarding the project, but in a less legible format.

Mr. Sharma also cited Schedules N2.1 and N2.2 of Exhibit A-24, which he described as the variance reports for 2019 and 2020 to show "where additional recovery is being sought."[892] These schedules show capital spending on the listed projects for each year that approximately totals DTE's additional capital spending of $46.63 million for 2019 and $40.99 million for 2020 above the amounts approved in Case No. U-20561. In general, the projects listed include many projects the Commission excluded from projected rate base in Case No. U-20561. As part of its rebuttal presentation, however, DTE presented an additional variance report, Schedule GG3 of Exhibit A-42 that compared DTE's rate case projections to actual spending for approved projects in

[890] As discussed below, DTE explains that its projects are given a prioritization score and enter a model that determines what projects to approve based on factors such as available funding and corporate priorities; project approval does not appear to be memorialized in any of the documents.
[891] 7 Tr 1927.
[892] 7 Tr 1935.

2020. Mr. Sharma seemed to characterize this as the variance report the Commission had required, but he further explained this schedule as follows:

> Using the requirements set forth by the commission, of the 68 projects greater than $0.25 million completed as required in Case no. U-20561 for the year 2020, which totaled $103.3 million in capital spend, the Company had [a] total actual spend of $105.4 million.[893]

As discussed in more detail below, although DTE presented this schedule to show that its total spending (for the approved projects) was close to its projected total spending, as Staff argues, this schedule is actually a significant indictment of the company's cost estimation process, which lacks credibility.

To understand some of the disputes in this case, it is necessary to understand the company's project initiation process and the documents it has submitted in this case. Mr. Sharma described DTE's project approval process, which he labeled the Annual Planning Cycle prioritization process (APC process), beginning with a "business case":

> The business unit project sponsor, with support from the IT Business Relationship Manager submits a business case into the IT APC process documenting the problem statement, functionality, or capability to be provided, value proposition, related key output measures, key objectives, alternative analysis, and a "Level 1" cost estimate. Level 1 cost estimates are based on historical spend analysis, subject matter expert input, and vendor partnership advisement. A project prioritization score (PPS) is then applied to the project based on the alignment of the investment to the Company's strategies and goals. The IT organization utilizes PPS to prioritize investments instead of other methods such as Net Present Value (NPV). Once the PPS is applied, the business case enters the enterprise IT Investment prioritization model where it is evaluated against capacity and company's financial plan. The model then optimizes the number of projects to be implemented by the Company. The company's Information

[893] 7 Tr 2134-2135.

Technology investment plan is reviewed and approved by the Company's executive Technology Investment Committee.[894]

Once a project has a prioritization score, it enters the IT investment prioritization model, and evolves through the planning process:

> Projects that are included in the IT investment prioritization model will evolve during the 2022 annual planning cycle, which ends in December 2022. Through this process the Level 1 cost estimate evolves into a "Level 2" cost estimate, which includes cost breakdown with internal labor hours, hardware and software cost, internal project management cost where required, and consultant and vendor quotes. The timing of detailed estimation within the Annual Planning Cycle (APC) process ensures that vendor quotes (which are firm for an average of 60 days) will still be viable for project execution. The established approval authorities within the APC process reviews and approves these business cases for project initiation. The "Level 2" business cases then transition into project execution at which time the "Level 3" scope, cost and schedule are managed.[895]

DTE relies on the project prioritization process "in place of a traditional benefit cost analysis." Based on its own reliance on its prioritization score, DTE declined to provide a quantification of benefits or a benefit cost analysis when requested. Ms. Pizzuti testified in response to a reduction recommended by Mr. Coppola based on his conclusion that a project had not been economically justified:

> It appears that Witness Coppola considers the Company's Project Prioritization Score (PPS), that is used by the Company in place of a traditional benefit cost analysis, as insufficient information to justify the capital expenditures being requested for these two digital projects. As shared in my answer to AG discovery question AGDE-8.286d and AGDE-8.286e (See AG Exhibit AG-1.23 pages 3-4), and 8.288c (See AG Exhibit AG-1.23 page 7), the Company uses the PPS score because it evaluates an IT capital investment across multiple business benefit categories in addition to cost. Since the PPS is used to assess one IT investment against another and for prioritization across the DTE IT investment portfolios in a consistent manner, it is a critical component of the

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[894] 7 Tr 1927-1928.
[895] 7 Tr 1928.

> Company's IT Annual Planning Cycle (APC) process that we began applying to IT projects beginning in 2022.[896]

DTE contends that it is unreasonable for a party to reject its prioritization score. Yet, there is no evidence on this record establishing that DTE's prioritization process is an adequate substitute for traditional reasonableness and prudence review. As noted above, DTE does not provide a quantification of benefits in its business case documents in the N1 schedules, nor does it provide one in Schedule N3. In the earlier business case documents in the N1 schedules, DTE frequently reported a "project prioritization score," but the more recent 2022 and 2023 business case forms do not report that score. Although DTE has a new prioritization score process as of 2022, Ms. Pizzuti clearly stated that it was not used in 2022.[897] Schedule N3 reports the score for 2023 projects only, but does not show any of its components. Ms. Pizzuti, however, provided some explanation of those components in her testimony as follows:

> Non-discretionary Regulatory/Compliance, Sustainment, and Return-to-Health projects were assigned a standard score and prioritized for funding in the following order – 1. Sustainment, 2. Regulatory/Compliance, and 3. Return-to-Health. Discretionary IT Enhancement and Strategic projects are prioritized for funding based on a scoring model that assesses their Strategic, Financial, and Operational impacts across the seven key attributes shown in Figure 8. Going forward, scoring category weighting is subject to change to ensure ongoing alignment with corporate priorities.[898]

She presented the following breakdown of the components of the prioritization score in Figure 8 of her testimony at 7 Tr 2166: strategic alignment (10%); customer experience (30%); employee engagement (10%); affordability and growth (20%); benefit/cost (10%); operational reliability (15%); foundational capacity (5%). The specific terminology

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[896] 7 Tr 2271.
[897] Exhibit AG-1.71, page 2.
[898] 7 Tr 2166.

used was not explained in greater detail. While disclaiming any prioritization for 2022 projects, as shown on page 2 of Exhibit AG-1.71, Ms. Pizzuti also provided one example of the 2023 scoring in response to the Attorney General's discovery following submission of her rebuttal testimony, as shown on pages 4-5 of Exhibit AG-1.71. Although it also shows a "benefit/cost" ratio as an element of the scoring, Ms. Pizzuti confirmed in Exhibit AG-1.71, page 6 that DTE did not perform such an analysis "as the Company uses PPS score in place of traditional benefit cost analysis as discussed in AGDE-11.407," which nonetheless refers to a "simple benefit/cost ratio" as shown on page 2 of Exhibit AG-1.71.

Since a benefit cost analysis is a small part, but plainly a part, of the company's prioritization, it is not understandable why the results would not be included the company's supporting exhibits. Instead, the company appears to believe that because it does not (or not extensively) rely on those analyses, it should not be expected to provide them. In Exhibit AG-1.22, page 4, the discovery question asked for "a copy of the cost/benefit analysis in excel with formulas intact showing that this program is economically justified." In Exhibit AG-1.23, page 3, the question asked for the "tangible benefits and cost savings that would result from the implementation of [the Digital Product Teams] on an annual basis and the year they would start." In Exhibit AG-1.23, page 4, the question asked for "the cost/benefit analysis that justifies spending the required capital on this [Digital Product Teams] project." As shown in each of these exhibits, the response in each case was an explanation that DTE "relies on a project prioritization score instead of a traditional benefit cost analysis for prioritizing IT investments," with additional references to Ms. Pizzuti's testimony and the N1 schedules in two of those documents. In answering the discovery questions cited above, DTE provided no insight into the prioritization scores for either of these projects, and as discussed below, not only did the company not report the components but did not even report the scores for the 2022 projects, contending it that because the scoring process was developed in 2022, it does not have prioritization scores for that year. Note that DTE acknowledges "reprioritization" of projects, as well.[899]

Another concern with the company's project documentation is the lack of clear project scope. Many projects encompass multiple goals and objectives, which are stated but not addressed separately through timelines or cost estimates. The objectives include broad generalities, and lack the specificity and objectivity that would facilitate audit of assigned expenditures. Take, for example, the "production growth" project on "line 11" of Schedule GG3 of Exhibit A-40 and line 14 of Schedule B5.7.1, in the "corporate applications" category. DTE presented this rebuttal schedule to show that in 2020, it spent a total of $105 million on projects that were approved in Case No. U-20561 in an amount totaling $103 million. DTE reports approved spending of $200,000, and actual spending of $134,000 in Schedule GG3 for 2020. Although shown on one project line of Schedule B5.7.1, there are four business cases listed for that project. The first, which is Schedule N1.38 of Exhibit A-24, has a capital expense amount of $750,000, along with $300,000 in O&M crossed out on one line with a note "no O&M." There is no project scope, but there are business outcomes and key objectives. The business outcomes are stated as:

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[899] See Sharma, 7 Tr 2032.

a) delivering adequate computing power, storage capacity, and middleware support to enable business growth and operational excellence;
b) Enabling IT business operations, and performing to the prescribed metrics and business analytics KPIs
c) Development and implementation of Agile/DevOps methodologies enabling increased agility and faster time to market[.]

The stated key objectives are:

1) Deliver new and consistent computing power, storage capacity, and middleware support to enable business growth and operational excellence.
2) Deliver a Agile/DevOps program to improve agility, collaboration, and speed to market for both IT and business focused outcomes.

There is no change document. The project start date is January 2020; the end date is January 2021. Notwithstanding the "business case" containing spending of $750,000 for 2020, DTE reports approved spending of $200,000 in Schedule GG3. Looking at the next business case document, the Schedule N1.39, this document includes a capital expenditure of $930,000 for 2021, with a project start month of January 2021 and a project end month of January 2022. The $930,000 in capital spending included on that document, for project outcomes identical to Schedule N1.38, does not match the $2.35 million included on Schedule B5.7.1 for 2021. In his testimony, Mr. Sharma refers to the purchase of a license for SQL server renewal for $2.2 million in 2021,[900] but he fails to explain why there is no supporting business case or change document for this change, or to account for the "business objectives" in the 2021 business case document. His testimony regarding the "alternatives" cannot be matched with the business outcomes or objects for the 2020 or 2021 program as discussed above:

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[900] 7 Tr 1949-1950.

> A "do-nothing" approach would include halting all upgrades, enhancements, and replacements of hardware and the requisite licensing and would mean the IT infrastructure could not meet and support the demands of the business and customer computing. Another option would be to purchase hardware and licenses on-demand or in an ad-hoc manner. This would cause unnecessary delays in implementation, increasing the impact on business and customers. In addition, it would increase the cost of the non-negotiated hardware/licenses as the Company would make each purchase individually instead of being able to take advantage of the economies of scale from a bulk purchase established by this business case.[901]

If this project is focused on bulk purchases of hardware and licenses, there should be a cost estimate based on each "negotiated" element.

In a similar vein, DTE also has a "production growth" project in the "plant and field" category, Schedule B5.7.4, line 8. This one is labeled "sustainment," while the project discussed previously was considered "IT enhancement." The schedule lists business case numbers that correspond to Schedules N1.109 through N1.112, one each for the years 2020 through 2023. Mr. Sharma testified that DTE spent $3.3 million on this project in 2020, "which is $2.5 million more than was included in rates for this project (in Case No. U-20561)."[902] He described this project:

> This project is to support the annual growth resulting from the ongoing increase in data and business processing needs. We will accomplish this by provisioning Just-In-Time computing power, storage capacity, database availability, and middle-tier infrastructure. As technology products approach the end of the product lifecycle, DTE must continue to make investments for supportability to ensure that software and hardware function to run the business. This project also enables IT business operations to perform to the prescribed CPU-capacity, storage thresholds, system response times, and availability.[903]

[901] 7 Tr 1950.
[902] 7 Tr 1997.
[903] 7 Tr 1997.

He explained the 2020 additional spending as follows: "In 2020 additional capital investments were approved which provided the opportunity to pull ahead procurement from the 2021 plan."[904] He did not present any documentation of this approval. The "business case" document for 2020 projected spending of $460,000;[905] the business case document for 2021 included only $290,000, so it would appear that there was no significant amount projected for 2021 to "pull ahead procurement" from. DTE includes $85,000 of the $290,000 in its rate case projection for 2021; again, there is no change document. Schedule N1.111 purports to cover the 11-month period from January 2022 to December 2022, but projects annual spending for each of two years at $795,549 each; DTE includes $625,000 online 14 of Schedule B5.7.4 for the 10-month bridge. Schedule N1.112 includes a projected spending for 2023 of $800,000, which matches the total spending DTE includes on Schedule B5.7.4. Again, there are no dates on these business case forms, but there is nothing in any of the documents that accounts for the additional $2.2 million in 2020 spending, or breaks down the total 2020 spending. The review of these and other documents leads this PFD to conclude that these and similar projects are essentially placeholders, which explains the significant variation in actual expenditures to forecast expenditures for these categories, with the company's focus on "spending" approved dollars, not meeting any particular or definitive program scope.

With that as background, Staff's general adjustments to the company's projections based on the company's own characterization of its cost estimates as "Level

[904] 7 Tr 1997.
[905] DTE reports approved 2020 spending of $800,000 for this project in Schedule GG3. If the approved amount were consistent with the provided business case, the overprojection in Schedule GG3 would increase from 316% to 624%.

1," "Level 2," or "Level 3," is discussed in subsection 2. Staff's concerns regarding DTE's capitalization policy is discussed in subsection 3, followed by a discussion of individual disputed line items.

2. Level 1 and Level 2 cost estimates

Mr. Sharma's description of the company's cost estimation process was described above. Staff raised a concern with the company's Level 1 and Level 2 estimations. Ms. Rogers reviewed the company's cost estimation process as described by Mr. Sharma.[906] Staff argues that the Commission should reduce DTE's projected expenses by $50.73 million to exclude its Level 1 cost estimates for the projected test year and by $19.6 million in the 10-month bridge period and $16.35 million in the test year to reduce its Level 2 cost estimates by 20%. DTE argues that its projections should be included in rate base.

a. Level 1 cost estimates

Focusing first on the Level 1 cost estimate, Ms. Rogers testified that 26 of the 100 business cases with 2023 capital expenditures have Level 1 cost estimates, as shown in Exhibit S-12.5, pages 3-4. Citing company audit and discovery responses in Exhibit S-12.5, Ms. Rogers explained Staff's recommendation that the Commission exclude all Level 1 cost estimates from the projected rate base in this case:

> Through audit and discovery, Staff made numerous attempts to understand the Company's methodology for estimating costs and the realm of accuracy of these estimates. Staff requested confidence intervals, accuracy ranges, and average differences between each level of cost estimate. The Company was unable to provide a response to any of Staff's inquiries. Without knowledge of how precise Level 1 cost estimates

[906] 8 Tr 5342.

> are, Staff believes it is unfair to pass the cost of the 26 projects on to ratepayers at this time.[907]

She further explained the uncertainty surrounding the Level 1 estimate:

> Level 1 cost estimates are not based on a request for proposal (RFP) and do not include a cost breakdown with labor hours, hardware costs, software costs, or internal project costs. From what Staff can discern, Level 1 cost estimates are immature and solely a concept being screened for feasibility within the Company's annual expense plan. A business case is given a cost estimate and prioritization score to determine where it fits within the Company's strategic and financial goals. If higher priority, unforeseen projects occur, projects with Level 1 cost estimates may be bumped further back in the implementation timeline or put on hold. While it may not be the Company's intention, if the cost of a lower priority Level 1 cost estimate project is pushed back long enough, it may not be executed at all.[908]

Staff's rejection of the Level 1 cost estimates results in a reduction in the company's projected IT capital expenditure of $50.73 million for the test year.[909] Ms. Rogers further testified that these projects have no historical spending, and also explained that it is the company's choice to file for recovery of these costs at the preliminary stage:

> The Company chooses to file a rate case with a projected test year. If they want to recover the projected costs, Staff believes it is the responsibility of the Company to have a mature and complete cost proposal prior to recovery through rates. Staff understands costs may change between initiation and end of the project; however, the Company has given Staff no way of determining how large or small this change is. At this time, there is insufficient evidence to be able to appropriately judge reasonableness and prudence.[910]

In rebuttal, Mr. Sharma disputed that a disallowance of the Level 1 cost projections is appropriate:

> The Company has made significant efforts to address feedback from Staff and the Commission in Case No. U-20561 by providing exhibits with

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907 8 Tr 5342-5343.
908 8 Tr 5343.
909 8 Tr 5344.
910 8 Tr 5443.

> additional project details. These exhibits include all the requested data and the associated workpapers which contain the requested project details, investment scope, cost estimates, benefits, and alternative and cloud strategy for investments in the test period. Staff Witness Rogers claims that the Level 1 cost estimates are "solely a concept being screened for feasibility" (page 9, line 15) is a misrepresentation of the Annual Planning Cycle (APC) process as provided in my testimony PS-5 line 25 – PS-6 line 1. The Level 1 estimate provided for investments in the test period is marked as Level 1 only because of the timing of the estimate and supporting level of detail required in the multiyear Annual Planning Cycle process. This should not lead Staff or the Commission to automatically assume that the known cost details are not sufficient and will "result in significant variance. Level 1 cost estimates are commensurate with the defined project scope and timelines and have been vetted thoroughly by the Company's Technology Investment Committee.[911]

Citing Schedule N3 of Exhibit A-24, he testified that DTE has provided a cost breakdown for these projects. He further testified that 6 of the 26 projects with Level 1 estimates are "repeatable" projects for which "the scope, implementation and technical details, resource requirements, and the timelines are very well-defined," so that "these projects should be viewed by the Commission with a high degree of confidence from the Company."[912] He testified that 14 additional projects are "like IT projects executed in prior years," "have a dedicated team that is well-versed in the workstreams, products, systems, technology, and underlying infrastructure they support," and in most cases, have "existing vendor partnerships already established on other in-flight projects and the vendors can advise on scoping and estimation efforts on future projects."[913] He considered this description to align with his description of Level 1 project estimates in his direct testimony. As to the remaining projects with Level 1 estimates, he acknowledged that they reflect new technologies, but asserted: "the scope is defined,

[911] 7 Tr 2129.
[912] 7 Tr 2130.
[913] 7 Tr 2131.

and the cost estimates were developed based on historical labor estimates for implementing technologies that are comparable in scale and complexity."[914]

Staff's brief reviews Mr. Sharma's explanation of DTE's APC planning process and Ms. Rogers' testimony in explaining why the Commission should adopt Staff's recommendation regarding the Level 1 cost estimates. Staff also addresses Mr. Sharma's rebuttal testimony at 7 Tr 2129, continuing to find the company's projections insufficiently definitive as to cost and timeline:

> Time and supporting level of detail are substantial factors of costs. A cost can increase or decrease significantly depending on the timeline of execution. Similarly, a detailed breakdown of complete costs is important to the accuracy of the expense as a whole.[915]

Citing Exhibit S-12.5, Staff further argues that it "made numerous attempts through audit and discovery to gain an understanding into the Company's methodology for estimating costs and the realm of accuracy of these costs." Staff acknowledges Mr. Sharma's testimony that DTE provided information as to project details, investment scope, cost estimates, and benefits, but argues this information "does not speak to the accuracy of the costs."[916] Staff emphasizes the company's choice to file the rate case, and the company's responsibility to ensure its projected costs are "mature and complete" prior to recovery through rates. Staff then asks the Commission to "request that the Company provide Staff with a more detailed cost estimate practice including confidence intervals and/or accuracy ranges."[917]

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[914] 7 Tr 2132.
[915] Staff brief, 98.
[916] Staff brief, 99.
[917] Staff brief, 100.

DTE relies on Mr. Sharma's testimony in its initial brief, and Schedule N3 of Exhibit A-24.[918] In its reply, it maintains that it does not evaluate confidence levels related to its cost estimates, and cites again to Mr. Sharma's rebuttal testimony in arguing that "in many instances IT projects are so substantially similar in many ways to past projects that is possible to provide concise estimates at the Level 1 estimation stage."[919] It argues that it has "properly supported the projects under the 'preponderance of the evidence' standard, and that Staff's doubts about cost accuracy do not justify a disallowance." It also considers that Staff's acknowledgement that DTE provided information necessary to understand the scope of the project is inconsistent with a complete rejection of the expense projections. DTE argues "[l]ack of precision does not equate to lack of existence,"[920] contends that Staff's reasoning is arbitrary,[921] and concludes that the project costs should be approved.

b. Level 2 cost estimates

Ms. Rogers also reviewed the company's Level 2 cost estimates. She described the Level 2 estimates as "the next step in the APC process" that "include more detailed costs, such as internal labor hours, hardware costs, software costs, any necessary internal project management costs, and vendor quotes."[922] She testified that all the remaining 2023 projects have Level 2 estimates, even for projects with historical

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918 DTE brief, 124-126.
919 DTE reply, 92-93.
920 DTE reply, 93.
921 DTE reply, 93 at n108.
922 8 Tr 5344.

spending, and all the 2022 capital expense projections are based on Level 2 estimates.[923] She explained the concerns Staff has with this level of cost estimate:

> Similar to Level 1 cost estimates, Staff unsuccessfully made many attempts to learn how the Company estimates costs. While Level 2 cost estimates are more mature and include a breakdown of cost criteria, these projected costs do not have a definite scope or schedule. As a result, these costs are incomplete. If a project is not under contract, there is no guarantee the business case won't change, be put on hold, or become unnecessary altogether. Staff believes it is unreasonable to pass this uncertainty on to ratepayers. Moreover, the Company did not provide enough information for Staff to determine if Level 2 cost estimates include more than one vendor quote or if one or more RFPs are sought, which can allow competitive pricing.[924]

With the exception of certain projects for which Staff has a specific adjustment, Ms. Rogers testified that Staff recommends a 20% reduction to the company's Level 2 cost estimates, explaining:

> Staff used the Association for the Advancement of Cost Engineering (AACE) International Recommended Practice Cost Estimation Classification and the limited information the Company did provide to assign Level 2 projects to an established class of estimate. As indicated by the Company, Level 2 projects include more detailed costs than Level 1 projects, including labor hours, hardware costs, and software costs, but lack a defined scope. Staff finds this level of cost information best applies to that of the AACE Class III estimate, with semi-detailed unit costs. AACE Class 3 estimates have a lower bound of 20%, meaning the actual cost could be as much as 20% less than the estimate. Therefore, Staff chose a 20% adjustment to reflect the amount that the Company could over-recover from Level 2 project cost estimates.[925]

Objecting to Staff's recommended reductions to the company's Level 2 analysis, Mr. Sharma asserted that these estimates are reliable, citing the variance analysis presented in Schedule N2 of Exhibit A-24, and further testifying:

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[923] 8 Tr 5344.
[924] 8 Tr 5345-5346.
[925] 8 Tr 5346.

> Witness Rogers claims that the Level 2 cost estimates are not based on a definite scope or schedule are inaccurate and in direct conflict with my testimony and submitted exhibits and workpapers. As outlined in my testimony and evidenced by the supporting exhibits and workpapers, the Level 2 projects are based on defined and detailed scopes and timelines and are thoroughly vetted by all IT department/teams during the cost estimation process.
>
> Additionally, 92 of the 108 total Level 2 projects ($31.54M of total $35.95M disallowance proposed) identified by Witness Rogers are in progress/ in-flight and the cost estimates are closer to the Level 3 cost estimate criteria. The Company believes that Staff Witness Rogers selection and recommendation of the lowest accuracy range provided for Class 3 estimates fails to consider that the AACE class 3 estimate also provides an upper range for Class 3 estimates at +30%.[926]

DTE's brief relies on Mr. Sharma's rebuttal, contending that Mr. Sharma's testimony and exhibits show 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."[927] DTE also cites Mr. Sharma's rebuttal exhibit, Schedule GG3 of Exhibit A-42, to show the accuracy of DTE's projections.[928]

In its brief, Staff argues that the Level 2 cost estimates are insufficiently precise to include in rate base, lacking a definite scope or schedule.[929] As with the Level 1 estimates, Staff argues that it made multiple efforts to obtain additional details regarding the company's cost estimation method and its level of precision, with no adequate response. Staff explains that it used the Association for Cost Estimation Classification system to establish an estimate class and associated error range. It agrees that there is an upper bound as well as a lower bound to the error range, but argues "Staff chose a

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[926] 7 Tr 2134.
[927] DTE brief, 126; DTE also cites Mr. Sharma's workpapers, which are not in the record of this proceeding.
[928] DTE brief, 127.
[929] Staff brief, 100-103.

20% adjustment to reflect the amount that the Company could over-recover from projects with Level 2 cost estimates."[930] Staff considers Mr. Sharma's rebuttal testimony that 85% of the projects are in progress and closer to a Level 3 estimate to be "new information" and argues that the company did not revise any of its cost projections. Staff also cites Mr. Sharma's rebuttal exhibit, Schedule GG3 of Exhibit A-42, noting that 38 of 68 projects for 2020 show underspending relative to the company's rate case projection for those projects.[931] Staff further points to the range of differences between the projected spending and actual spending, from -100% to +316%, "causing Staff to greatly question the company's estimation practice."[932]

In reply, in addition to repeating the argument in its initial brief, DTE addressed Staff's conclusions based on its review of Schedule GG3, arguing that Staff's focus on 38 of the projects "neglects the Company's point." DTE explains that its point is that "even assuming inaccuracy in individual project estimates (as Staff suggests), the over-projections and under-projections offset each other, tending back towards the overall projection (a collective variance close to 0)."[933] It argues that "a similar overall projection accuracy can be expected for the 108 projects at issue here." DTE considers Staff's adjustments arbitrary, and also contends that if any reduction should be made, it is the 15% reduction based on the AACE class 2 estimates.

c. Findings and conclusions

After reviewing the record evidence, this PFD finds that DTE's cost estimates are unjustified and unreliable. The Commission provided DTE with the option to wait to seek

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[930] Staff brief, 102.
[931] Staff brief, 102-103.
[932] Staff brief, 103.
[933] DTE reply, 95.

cost recovery until its IT expenditures had been made. DTE nonetheless chose to request recovery of projected expenses in this case, without conforming to the requirements the Commission put in place for justification of those expenses. As Staff argues, it made several efforts to understand the company's expense projections. Exhibit S-12.5, page 1, asks for an explanation of the types of estimates used to predict project costs, and DTE's answer is only to refer to Mr. Sharma's testimony. Page 2 of this exhibit asks for "confidence intervals or accuracy ranges of each estimate type used," and the response states:

> The Annual Planning Cycle applies progressive elaboration of estimation as defined in [Mr. Sharma's testimony at 7 Tr 1928]. For this reason, the dependence on accuracy ranges and confidence intervals are not called out.

Page 5 of Exhibit S-12.5 asks for the Level 1 estimates that were associated with the projects listed in Schedule N3 that currently have a Level 2 estimate. The answer states: "We do not track level 1 to level 2 cost estimation % difference but have provided a copy of each business case where applicable." A similar answer is provided on page 6 in response to a question seeking Level 2 analyses associated with projects that currently have a Level 3 estimate. DTE provided these answers even though it contends on page 9 that each project will have a Level 1, a Level 2, and a Level 3 cost estimate before project execution. DTE also established actual approvals for no projects. As shown on pages 10 through 12 of Exhibit S-12.5, Staff asked the question "will all IT projects . . . be executed?" for each of the Level 1, Level 2 and Level 3 projects, and DTE answered "Yes," with what seems to be a caveat "all IT projects designated as Level 1 cost estimates are planned to be executed," "all IT projects designated as Level 2 cost estimates are planned to be executed," "all IT projects designated as Level 3 cost estimates are planned to be executed." As shown on page 17 of Exhibit S-12.5, DTE explained its Level 3 cost estimates: "Level 3 cost estimate is developed after the project begins and is part of the project execution, and mostly occurs in the planning phase of the project." The answer also cited Mr. Sharma's testimony at 7 Tr 1929 for additional details, which in turn refers to the company's five-year plan.

Looking at DTE's defense of its Level 1 analyses, a review of the business case documents DTE introduced as N1 schedules shows that Mr. Sharma's testimony that certain line item projections are duplicates of prior projects or "repeatable" is not persuasive. First, as noted above, the company's projections are not transparent, and there is nothing in those documents that shows how the cost projections are made, including nothing that references prior projects for which these are repetitions of prior projects. Because it is not possible for this PFD to discuss each of the projects in the disputed categories, so this PFD will discuss key examples.

As an example of a "repeatable" project identified by Mr. Sharma, this PFD considers the P&F Enhanced Document Management Capability Projects, with projected 2023 capital cost of $3.03 million, Schedule N1.106, page 136 of Schedule N1, has only first year capital spending of $3.88 million and O&M of $227,702; although it states the project will begin in 2023 and end in 2025, no start month or end month is shown. The problem is stated as: "There is a case for change proposing to address gaps identified by the Plant & Field (P&F) Document Management Governance Board led by business units (BU's) to define an aligned strategy in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged."

The boxes for system or process being affected and alternatives considered are blank. The box for the functionality or capability being provided states: "With a defined document management strategy that spans across BU's, organizations could expect to see benefits such as productivity and efficiency improvements, reduction in operating costs, higher team engagement and elevated protection and management of critical information." The customer or employee value box states: "Defining a common document management strategy that can span across all P&F BU's and addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged." Under key objectives, it is broadly stated:

1. Automate document workflow to streamline business processes consistently. Automate the addition of new documents as well as version control of existing documents, and the ability to create digital forms of existing documents for review and approval. Create a well-managed process for requesting access to Documentum

2. Integrate documents to work management tools & other systems. Integrate documents to Work Management Tools & Other Systems (Maximo, ESRI, Sharepoint, Clicksoft) and support the ability to link video and photos to Maximo object structures and Work Orders. Assign records to specific asset within the workflow process. Develop electronic work packages, approvals, etc

3. Enable digitalization and indexing for existing scanned paper documents. Enhance search capabilities for quick and accurate document retrieval. Streamline access to records with keyword and full-text searching. Digitize the archive of paper documents and make searchable by specific criteria to support paperless workflow processes.]

4. Ensure safety and reliability of systems by enabling record retention. Create well defined and accessible Business Record Retention Policies and maintain compliance with system support. Develop a record policy enforcement process for the management of older/expired system documents.

5. Maximize agility and responsiveness by implementing capabilities to improve effective process collaboration. Support document processing

> methods designed to be used simultaneously by several users on the same content item. Increase efficiency, improve information control, and reduce the overall cost of information management and digital archiving. [missing text][934]

Schedule N3, line 277 states:

> This project is intended to address gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. The areas of focus are automation of document workflow to streamline business processes consistently and integration of documents to work management tools & other systems. With the implementation of these new capabilities, Plant and Field business units will see benefits such as productivity and efficiency improvements, reduction in operating costs, higher team engagement and elevated protection and management of critical information. Costs were developed through collaboration between DTE IT and vendor partnership with Flat Iron, a trusted vendor who implemented the Documentum Re-platform project, and the product vendor OpenText. The alternative would be to continue to use the existing manual business processes with the same gaps and inefficiencies, which is very labor intensive. Other technologies were not considered as DTE has recently invested in the OpenText Documentum and this investment is aligned with our Platform Strategy.

This line also shows the project starting in 2023 and continuing to 2025. This line shows the $3.8 million total capital cost split into relative equal amounts for capitalized labor, “other” capital, and “overhead. ($1,260,000 $1,416,000 $1,204,000) and it reports a project priority score of only 4.3.

As an example of the second category, “like IT projects executed in prior years,” the largest expense is for “web transformation,” with a projected cost of $9.12 million in the test year. A review of the information DTE provided in Exhibit A-24 shows confusion, a low prioritization score, and no support for the claim it is “like IT projects executed in prior years.”

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[934] As noted above, the form of the document is difficult to work with and text that is not visible on the page can be extracted to some extent with a copy-and-paste method. To be fair to the company, and for completeness, an attempt has been made to do that here.

Schedule N1.416, pages 575-577, states that the project will begin in January of 2023 and end in December of 2025, but it reports only “first year” costs of $11.68 million, with nothing for the following years. The “business problem” is identified as follows:

> The digital web channel today is a composite of disparate experiences delivered over 18 years. These experiences are delivered to customers over multiple technology platforms. New customer journeys for outage, payment, and start/stop/transfer have been built as "one-offs" and other customer-facing web transactions remain on older technology. The result is a customer web experience that is disjointed, inconsistent, and at times confusing to customers.

The boxes to explain the system or process being affected and to identify alternatives considered are completely blank. The description of the functionality or capability being provided states:

> This multi-year program contains multiple workstreams, working in concert to redefine and deliver new customer web experience. The Product Transformation Teams established in 2022 will continue to evolve the outage, billing, payment, and move-in/move-out (MIMO) transactions, specifically focused on integrating their products into the new web technology platform and improving navigation and cross-product experience.
>
> Customer new product teams: New product teams will be established to define customer journeys for remaining web capabilities, including Collections, Billing & Payment History, Program Enrollment, Rebate management, and others.
>
> Customer profile & preference: Will build a new customer profile and preference management web experience for customers.
> API layer on top of billing system: Supporting workstream to enhance core billing system APIs, exposing data and transaction functionality as needed by Product Transformation Teams.
> 3. Enabling Elements - personalization: Supporting workstream to create personalized program recommendations and communications, and further personalize web experience
>
> 8. Work mgmt. & field services - Work order: Supporting workstream that will make relevant changes to plant & field work management systems, in

support of continued journey work performed by Product Transformation Teams.

The customer or employee value is described as follows:

> Customers will benefit from consistent, frictionless journeys through the web channel. Navigation will be consistent across all business transactions. All transactions on the digital web channel will be available and able to serve customers even during storms and high traffic. Employees will benefit through fewer customer complaints for web issues, and the ability to make rapid changes to the web channel in response to feedback and analytics.

Although Schedule N3, page 24, line 271, identifies spending for 2023 in the first box, the line also reports that the project will begin in 2022 and end in 2023, which is inconsistent with the dates provided in Schedule N1.416, as discussed above. The line shows a total capital cost of $11.68 million, broken down into labor costs of $1,177,000, "other" capital costs of $8,891,500, and "overhead" costs of $1,611,500. With no explanation of the basis of the cost estimate or a calculation of benefits presented, and a "project score" of only 6.3, the text states:

> The Company is investing in a multi-year program with multiple workstreams, that will redefine the customer web experience. The digital product teams will continue to evolve the outage, billing, payment, and move-in/move-out (MIMO) transactions, specifically focused on integrating their products and solutions into the new web technology platform and improving navigation and cross-product experience.
>
> Included in this transformation are multiple workstreams (listed below), each targeting an area of the web that will enhance the customer experience, with a focus on the ease with which the web can be updated and enhanced.
> Workstream No. 1 – Profile and Preference Management Center
> Workstream No. 2 – Personalized Digital Experiences
> Workstream 3 – Improve Data and Transaction Functionality Workstream No. 4 – Work Management and Field Service[.]

These references to the customer journey and customer experience are ubiquitous throughout the company's project descriptions and do not help to distinguish one project from another or allow verification when the project has been completed. For example, the description for the "customer journey transformation external system support" states:

> In alignment with Witness Pizzuti Customer Journey testimony this investment will make the required changes to Plant & Field work management systems by product transformation teams and the required changes to the Outage Management System (OMS), as needed and identified by the Outage product transformation team. Customers will benefit from consistent, frictionless journeys through the web channel. All transactions on the digital web channel will be available and able to serve customers even during storms and high traffic. Customer Service employees will benefit through fewer customer complaints for web issues, and the ability to make rapid changes to the web channel in response to feedback and analytics. A "do nothing" alternative would result incomplete requirements to the Plant and Field and Outage Management systems that are utilized to support and fulfill the Customer Journey investments and therefore was rejected[.][935]

Regarding the Level 2 analysis, while Staff notes the company's claims that there is more substance to these estimates, nothing in the company's documentation in this case supports the legitimacy of the analysis. As discussed above, the Schedule GG3 analysis DTE offered shows an extraordinarily wide error range associated with these estimates. Contrary to the Commission's instructions quoted above, no "change documents" were ever produced for these projects explaining the reasons. While DTE argues that its total spending close to the total rate case amount justifies the company's projections, as explained above, that would make sense only if the primary goal of the rate case prudency review is to assure that DTE will spending at least a specific amount of money on IT projects as a whole. In view of the project-by-project errors shown in Schedule GG3, DTE's claim that its Level 2 estimation process is akin to the AACE

[935] Exhibit A-24, Schedule N3, page 23, line 252.

Class 2 project with error ranges on the low side of -5% to -15% and on the high side, of 5% to 20%, is unsupported. Indeed, a review of the line items in Schedule GG3 shows 26 of the underprojections are -20% or greater, and 18 of the overprojections are +30% or greater; that is, 42 of the 68 line items (62%) show projection errors in the Class 6 estimate band or worse than the Class 6 estimate band. As shown in Mr. Sharma's chart, the Class 2 AACE estimate is also based on a "detailed unit cost," which DTE has not provided for any of its projections.

Because Staff's analysis provides a reasonable approach to what is otherwise a non-conforming and unsupported collection of cost estimates, with no established reliability as shown by Schedule GG3, this PFD finds that Staff's recommendations should be adopted for those projects, with exceptions for any other recommended adjustments that are discussed in more detail below, that obviate or duplicate Staff's Level 1 and Level 2 adjustments. The company's contention that whatever level of imprecision is included in its estimates, some amount of funding should be provided for its projects, is rejected.

As discussed below, Staff also recommends an additional adjustment to DTE's expense projections, primarily to the 2021 projections, for four projects specifically based on historical underspending, which Staff equates to a measure of forecast error. Those recommendations are discussed in conjunction with the individual line items at issue.

3. Corporate applications (Schedule B5.7.1)

a. Level 1 estimates (B5.7.1, lines 8, 18, 22, 23)

For the reasons stated above, this PFD concludes that Staff's exclusion of projected test year expenditures for Level 1 estimates should be adopted.

Level 2 estimates (B5.7.1, lines 1, 3-6, 11-14, 16-17)

For the reasons stated above, this PFD concludes that Staff's recommended reductions to projected 10-month bridge and test year expenditures for Level 2 estimates should be adopted.

b. Controllers financial planning tool (B5.7.1, line 20)

The controllers financial planning tool project falls within the corporate applications "portfolio" in DTE's IT expense categorization. As shown on line 20 of Schedule B5.7.1, the company projects capital expenditures of $2.19 million in the 10-month bridge period and $0.63 million in the test year for this project. Mr. Sharma described this project as intended to "implement a Financial Planning tool for the Controller's organization which will manage our financial planning processes."[936] He described the current state of the financial forecast process as "not sustainable," citing issues with Excel. He described as the program used to manage forecast and budget process, and stated concerns with its file size limitations, a "risk of human performance errors,"[937] and a cumbersome reliance on a manual forecast consolidation process. He testified that "[t]he implementation of a financial planning tool will improve the forecast cycle time - reduction in time to publish by about 10%, improve process efficiency

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[936] 7 Tr 1958.
[937] 7 Tr 1958-1959.

resulting in about 10% labor time savings and improve forecast accuracy by approximately 5% through elimination of human error." He testified that the company considered a 'do nothing' approach as an alternative, but testified this "would significantly impact the financial planning process, continue to risk the loss of data and human error in data entry," and DTE "would be unable to gain process efficiencies." He asserted that the company's cost estimates were determined "by leveraging industry experience for implementation of like systems in an Enterprise the approximate size of DTE."[938]

Ms. Rogers explained Staff's recommendation that the costs be excluded from rate base "until the Company has a firmer plan for implementation in place."[939] She further explained that Staff believes it is premature to provide funding for a project that is still in the investigation phase, with cost estimates "likely to vary depending on the vendor and complexity of the program solution."

In rebuttal, Mr. Sharma offered an update on the company's cost projection:

> I disagree with the recommendation as this project had a level 2 estimate that included an estimate that reflected the costs of the products that were considered, and scope details were provided. The Company finalized product selection, Oracle EPM product, which was one of the alternatives considered when developing the estimate. This product was reviewed and approved by the Company's architecture team as a viable solution to replace the current SAP BPC Planning tool. This project is currently in progress following the completed analysis.[940]

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938 7 Tr 1959. (He capitalized the word enterprise, which is a program DTE uses, but from context, it appears he is referring to a business entity generically.)
939 8 Tr 5352.
940 7 Tr 2143.

In its brief, Staff argue that the Commission should exclude the projected costs for this project from rate base.[941] It argues that Mr. Sharma's rebuttal does not contain sufficient information to justify the expense, including "why this product was selected, the benefits it will provide over the other options, or how the cost is affected in comparison to other products."[942] Staff notes that Staff and intervenors cannot assess the prudence of information provided at the rebuttal stage of the proceeding. As noted above, Staff uses this project as an example of the uncertainty of the company's Level 2 cost estimates, questioning "how accurate a Level 2 cost estimate can be if the Controllers Financial Planning Tool project had a Level 2 cost estimate yet lacked a product selection."[943]

DTE argues that its Level 2 estimate "reflected the costs of the products that were considered, and provided scope details," and further argues the project is in progress.[944] It also notes Ms. Rogers' testimony that Staff does not oppose to this type of investment. In its reply, DTE argues on this basis that Staff's concern has been addressed. It characterizes a 100% disallowance as "draconian," arguing "[p]lainly, the cost is not zero."[945]

This PFD finds that Staff's adjustment is appropriate. Consistent with Ms. Roger's testimony, the company's business case document for this project, Schedule N1.9 of Exhibit A-24, clearly states: "UI Planner, Oracle, Onestream, IBM, SAP and other solutions are being investigated." The Commission has been clear that the

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[941] Staff brief, 107.
[942] Staff brief, 107.
[943] Staff brief, 108.
[944] DTE brief, 137-138.
[945] DTE reply, 108.

company is not allowed to rely on placeholders and substitute a more complete project in rebuttal, when the parties are not able to analyze it at that stage of the proceeding. In contrast, as Staff argues, Mr. Sharma's rebuttal testimony raises more questions than it answers, including questions as to the competing bids and the company's other considerations in seemingly choosing Oracle, and questions regarding the meaning of his statement about replacing "SAP BPC," when his direct testimony only mentioned concerns with Excel, and the business case document states that Excel "gathers data from various sources, including SAP, BPC, Power Plan, among others."[946] In Schedule N3, page 12, line 119, no prioritization score is shown, and the text box essentially repeats Mr. Sharma's testimony. Both N1.9 and N3, line 119 show all spending for this program in 2022, so something clearly changed from those documents to the company's Schedule B5.7.1.

c. Reservation Application (B5.7.1, line 21)

Schedule B5.7.1 shows projected spending of $0.5 million in the 22-month bridge period. Mr. Sharma testified:

> The SaaS solution, known as Serraview Engage, will be developed, and deployed to support mobile and stationary employees, allowing them the ability to reserve workspaces, utilizing a graphical user interface showing the floor plan with available seating locations, and reserve the necessary equipment at an on-site facility and assign spaces for new mobile workforce for employees without an assigned seat.[947]

Regarding alternatives, he testified:

> The "do nothing" alternative was rejected as it would not provide employees the visibility to secure a work location with the necessary equipment. This would also not allow the company to intelligently manage

[946] Exhibit A-24, Schedule N1.9.
[947] 7 Tr 1960.

and right size our facilities footprint aligned with FWWW strategy. Finally, a do-nothing approach would limit our ability to provide a safe environment for our employees to work and collaborate.[948]

Ms. Rogers explained Staff's recommendation to reject the projected bridge period spending:

> In terms of priority investments, this is a time when the Company is looking to make significant infrastructure investments to improve safety and reliability. The Reservation Application does neither of these things. There are many less expensive options available to accomplish the same task. Possibilities include programs the Company likely already has access to, such as Microsoft Outlook, Excel, and SharePoint. Such alternatives are not discussed by the Company. Additionally, the COVID pandemic is transforming to an endemic state. The government orders for social distancing and mask wearing have been rescinded. The ability to contract trace and sanitize workspaces and equipment daily are not reliant on the Reservation Application software.[949]

In rebuttal, Mr. Sharma objected:

> This project started execution during the COVID-19 pandemic state. The Company is using the existing application of MS Outlook, which has limited capabilities to [fulfill] the requirements set out in this project. The Company did use MS Outlook to interface the reservation application to reduce the cost to implement a complete solution with calendar entries. Furthermore, while COVID-19 may be in the current endemic state there continues to be requirements to maintain the health and safety of the Company employees through social distancing and contact tracing requirements, and it positions the Company for any future outbreaks. The assertion that the Company could contact trace and sanitize used facilities in an effective way without this application misrepresents the complexity of the manual effort needed to complete contact tracing and sanitization requirements.[950]

Staff argues the Commission should reject the projected spending as an unnecessary cost to ratepayers.[951] Staff notes that DTE characterizes the MS Outlook it

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[948] 7 Tr 1960.
[949] 8 Tr 5347.
[950] 7 Tr 2141.
[951] Staff brief, 103-105.

is currently using as limited, but does not detail what the limitations are, and do not evaluate alternatives already owned by the company.

In its brief, DTE disputes “all the suggested reasons for a disallowance,” arguing that the project started during the pandemic and there are continuing requirements to maintain employee health and safety through social distancing and contact racing, as well as the potential for future outbreaks.[952]

Consistent with Ms. Roger’s testimony, while Mr. Sharma referenced the limits of Outlook in his rebuttal testimony, nothing in the company’s business case documents in this case reflect an organized consideration of alternatives. Instead, the business case document in Schedule N1.43 reports 2021 capital costs of only $320,000, and does not match the company’s cost projection in Schedule B5.7.1. It is also worth noting that as part of the company’s 2021 business case format, there is a statement of the cost of “hardware/software/cloud,” which indicates that portion of the cost projection is only $55,000. Neither Schedule N1.43 nor Schedule N3, page 2, line 12 has a prioritization score for this project, which has clearly evolved, at least in cost, since the business case was prepared.

4. Customer Service (Sustainment) (Schedule B5.7.2)

The only disputed items on Schedule B5.7.2 for the Customer Service—sustainment category involve Staff’s Level 1 and Leve 2 estimates. For the reasons discussed above, this PFD finds Staff’s revisions should be adopted.

[952] DTE brief, 136-137.

a. Level 1 estimates (B5.7.2, lines 7, 13, 19)

For the reasons stated above, this PFD concludes that Staff's exclusion of projected test year expenditures for Level 1 estimates should be adopted for Schedule B5.7.2.

b. Level 2 estimates (B7.5.2, lines 1-6, 10-12, 14-15, 17-18, 20)

For the reasons stated above, this PFD concludes that Staff's reduction to DTE's bridge and test year Level 2 expense projections should be adopted.

5. Customer Service (Strategic, Enhancements) (Schedule B5.7.3)

Ms. Pizzuti presented testimony in support of IT customer service capital expenditures on Schedule B5.7.3. This schedule reflects the subset of IT customer service expenses in the "Customer Service (strategic, enhancements, and compliance)" portfolio as shown on line 4 of Exhibit B5.7, page 1.[953] As shown on that line, DTE reported 2020 expenditures of $41.77 million and projects 2021 expenditures of $39.69 million, 10-month bridge period expenditures of $57.89 million, and test year expenditures of $56.44 million. Ms. Pizzuti described the expenditures in this portfolio category as "those non-discretionary and discretionary projects that are required by mandate or compliance rules, or directly target customer interactions and the customer experience."[954]

As background to her discussion of specific line items, she discussed DTE's motivating concept of "distinctive service excellence." She illustrated the company's focus on four keys of a culture of service—safe, caring, dependable, and efficient—and

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[953] As noted above, DTE revised its portfolio categories, dividing customer service into two categories, and eliminating the 'technology and architecture" portfolio category.
[954] 7 Tr 2163.

on transactional excellence.[955] She also explained that DTE views its customer experience as defined by “journeys,” providing a visual depiction of the five highest-volume customer journeys in her Figure 3: move-in/move-out (MIMO), billing, payment, collection, and outage.[956] She testified that the while the “customer IT portfolio” prioritizes these five customer experiences, “the Company continues to commit resources and capital to IT projects that will enhance the customer experience across all customer interactions.”[957]

Ms. Pizzuti also explained that DTE is using six “best-in-class” customer design principles “that are necessary to create a distinctive customer experience:” simplicity, convenience, interactivity, desirability, seamlessness, and accountability.[958] She summarized some common “gaps and opportunities for improvement” in customer journeys that DTE has identified that inform its design and prioritization of projects:

- Simple & convenient self-serve options not available for all journeys
- Customer journeys are not always seamless across service channels
- Inability for customers to view and track status of orders & inquiries
- Limited use of customer segmentation to personalize the experience
- Limited use of proactive and closed-loop customer communications
- Limited interactive analysis tools for customers
- Lack of timely & relevant information for payment plan customers[959]

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[955] 7 Tr 2153-2155.
[956] 7 Tr 2157.
[957] 7 Tr 2157.
[958] 7 Tr 2158.
[959] 2158-2159.

While deferring to Mr. Sharma for greater detail, she also discussed the company's prioritization process for IT expenditures, testifying:

> Each of the projects with 2022 and 2023 bridge and test year capital expenditures in the Customer IT Portfolio were assessed against other investment opportunities and project alternatives and were selected for inclusion in the portfolio using this PPS prioritization model.[960]

She testified that projects that are considered non-discretionary are "assigned a standard score," while discretionary expenditures in the "strategic" and "IT enhancements" categories "are prioritized for funding based on a scoring model that assesses their Strategic, Financial, and Operational impacts across the seven key attributes shown in Figure 8" at 7 Tr 2166. Figure 8 shows a 10% weighting for "strategic alignment," a 30% weighting for "customer experience," a 10% weighting for "affordability and growth," a 10% weighting for "benefit/cost," a 15% weighting for "operational reliability," and a 5% weighting for "foundational capacity."

While Schedule B5.7.3 orders project line items by the company's major categories (regulatory/compliance, IT Enhancement, strategic), Ms. Pizzuti also related groups of line items to what she identified as DTE's five strategic goals. Under the rubric of the first goal, "digital and voice interactions," she identified line items in Schedule B5.7.3 corresponding to $44 million in capital expenditures over the period 2020 through the projected test year. These line items are further subdivided into "digital product teams" (lines 42, 43, and 49), "digital platforms" (line items 32, 33,51 and 52), and "digital and voice self-service" (lines 34, 47, 48, and 50).[961] Under the rubric of the second goal, "transactional excellence", she identified line items

[960] 2165-2166.
[961] 7 Tr 2188-2211.

corresponding to $40 million in capital expenditures over the period 2020 through the projected test year, further subdivided into "core systems" (lines 35, 37, 45, 46, and 54), "new solutions/capabilities" (lines 36, 38, and 40), and "communications platforms" (lines 39, 44, 53).[962] She explained that the focus under this goal is on "closed loop customer journeys," which she defined further, in order to "deliver Distinctive Service Excellence" for the company's customers.[963] Four line items are each specifically assigned to one the remaining strategic goals, "reform the collection experience" (line 57),[964] "develop customer centric rates and programs" (line 52),[965] and "expand data analytics capabilities" (lines 31 and 41).[966]

In addition to its adjustments targeted at the reliability of the company's cost estimates and Staff witnesses Ms. Rogers and Ms. Armstrong recommended that the Commission reject or substantially reject several line items as not having been shown to be in customers' best interest. Ms. Armstrong provided a general explanation of Staff's concerns:

> Staff has concerns regarding the methodology used to justify the numerous IT projects identified to enhance the customer experience. Staff understands the Company's desire to improve their relationship with their customers; however, the impetus of the proposed enhancements stems from suggestions generated by DTE Staff and not customers directly (Company CLK 2.12 audit response, Staff Exhibit S-21). The Company admits that they declined to research customer service best practices with peer utilities, instead opting to research and adopt best practices of successful private companies (Company Exhibit A-24, Schedule N1.345; Company CLK 1.17 audit response, Staff Exhibit S-24). Staff opines that this methodology is flawed because the best practices of companies in the free market rest on the assumption that customers have the freedom to

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[962] 7 Tr 2211-2231.
[963] 7 Tr 2211.
[964] 7 Tr 2231-2233.
[965] 7 Tr 2233-2235.
[966] 7 Tr 2235-2237.

> choose another provider if they are dissatisfied with their service, and this is not the case for most of DTE's customers. As customers of a regulated monopoly, ratepayers are obligated to pay the Company or risk having their electric service disconnected; therefore, Staff opines that there is a finite level of customer satisfaction that can be reasonably achieved in a captive market.
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> Moreover, based on Staff's experience dealing with the customer complaints of Michigan's ratepayers, their concerns mainly lie in the actual reliability, cost of service, meter reading, and accurate billing, not in alternative technologies to communicate with the Company regarding their service.[967]

As discussed in more detail below in connection with individual line items, she also took issue with the company's use of a reduced call volume as a benefit, citing concerns that technical complexities would increase the number of calls, and also noting DTE's plans to increase the number of Customer Service Representatives.[968]

In her rebuttal, Ms. Pizzuti defended the company's use of companies in competitive retail markets to set its goals: "The Company's goal of delivering Distinctive Service Excellence should not be limited to the best practices of peer utility companies, as customers often will compare their experiences with DTE to that of their other non-utility service providers."[969] She stated that DTE nonetheless does not ignore the best practices of peer utilities. She also contended that Ms. Armstrong wrongly stated that customers are not concerned with digital technology.[970]

Staff reiterated the concerns expressed by Ms. Armstrong and Ms. Rogers in its brief,[971] providing the following overview:

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[967] 8 Tr 5489-5490.
[968] 8 Tr 5490-5491.
[969] 7 Tr 2258.
[970] 7 Tr 996.
[971] Staff brief, 124-126.

> As a justification for investing $100 million over 46 months, the Company strives to mimic the accoutrements of digitally based companies such as Amazon and Uber. In rebuttal, Company witness Pizzuti states that "[t]he Company's goal of delivering Distinctive Service Excellence should not be limited to the best practices of peer utility companies, as customers often will compare their experiences with DTE to that of their other non-utility service providers." (7 TR 993.) While this may be so, the Company's customers do not have the option of shopping based on price, quality, or ease of service. If distinctive customer service requires digital enhancements that are not prudent or are very costly with little associated cost savings or demonstrated ease for the customer, then the comparison with nonutility service providers is irrelevant.[972]

MI MAUI and Ann Arbor endorsed Ms. Armstrong's testimony in its brief. Several witnesses for MI MAUI, Ann Arbor, and DAAO also testified to their paramount concerns with the reliability of DTE's service, as noted above.

DTE relies on Ms. Pizzuti's testimony in its brief, and argues that it has many projects targeted to cost savings, reliability, and safety, but "also evaluates the strategic nature of a project and if it supports a broader and multiyear 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."[973] Thus, the Company appropriately identified product and service providers that are considered the "best" in delivering the key elements of a distinctive experience.

a. AACP/Time of Use (Schedule B5.7.3, line 1)

Staff and the Attorney General recommended that the Commission exclude all contingency amounts from the company's projected expenditures for the Advanced Customer Pricing Pilot/Time of Use project, which is shown on line 1 of Schedule B5.7.3

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[972] Staff brief, 125-126.
[973] DTE brief, 131.

as part of the "customer service" portfolio. Mr. Coppola cited the company's discovery response in Exhibit AG-1.2[974] and Ms. Rogers cited the company's discovery response in Exhibit S-12.12 to show that the company included $2.1 million in contingency in the bridge year and another $2.1 million in contingency in the test year projection.[975]

Mr. Coppola also objected to the non-contingency portion of the company's projections, characterizing it as an "extraordinary amount."[976] He reviewed the history of the Commission's approval of the underlying pilot programs, focusing on reductions in the number of rate schedules affected. He recommended that the Commission immediately suspend approval of the pilots and decline to approve additional spending until an evaluation can be undertaken of the program costs. He presented Exhibit AG-1.21 to show DTE's breakdown of $73.4 million in past and projected costs between the pilot program and the TOU full implementation.[977]

Ms. Pizzuti presented limited direct testimony in support of the company's projection, discussing the delay in the pilot launch to March 2021 due to COVID, referring to Mr. Foley's testimony regarding the company's proposed TOU rate in this case, and citing the cost projections on line of Schedule B5.7.3.[978] In her rebuttal, Ms. Pizzuti testified that the Attorney General did not understand that the projected costs are not only for the pilot, but for the expansion of the program to full implementation of

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[974] 8 Tr 4749-4750.
[975] 8 Tr 5338.
[976] 8 Tr 4802-4803.
[977] This exhibit reports total costs for the ACPP pilot as $17.3 million in capital and $7.78 million in O&M for a total of $25.1 million. For the TOU program, DTE projects 2022 and 2023 total costs of $47.2 million, including $30.1 million in capital and $17.1 million in O&M costs.
[978] 7 Tr 2168-2169.

TOU rates.[979] She testified that it is imperative that the project is not delayed, and cited the company's "alternative" TOU proposal discussed by Mr. Foley in his rebuttal testimony. She testified that this alternative proposal would have a projected IT cost of only $10.1 million in the bridge period and $9.4 million for the test year, 35% below the company's current projection. She did not address Mr. Coppola's testimony regarding the company's cost projections in Case No. U-20162.

In his rebuttal, Mr. Foley presented Schedule JJ1 of Exhibit A-45 as the company's alternate TOU proposal, which was initially provided as an audit response to Staff and included in Exhibit S-23.01. He testified that this alternative proposal would apply TOU pricing to both capacity and non-capacity portions of power supply costs.[980]

In its brief, DTE argues based on Ms. Pizzuti's testimony that the Attorney General misunderstood the projected expenditures, which it contends are for full implementation of time of use rates, and that the Commission directed DTE to achieve full implementation for the summer of 2023. DTE also notes its alternative plan included in Staff's Exhibit S-23.01, as discussed by Mr. Foley.[981]

In its brief, citing Mr. Revere's testimony,[982] Staff supports the company's alternative plan and the corresponding costs.[983] Other than noting Staff's approval, DTE's reply brief repeats the arguments in its initial brief.[984]

In her initial brief, the Attorney General argues that Mr. Coppola reasonably challenged the company's $73.5 million expense projection as extraordinary, and that

[979] 7 Tr 2268-2269.
[980] 6 Tr 1191-1192.
[981] DTE brief, 140; also see DTE reply, 110-111.
[982] 8 Tr 5136-5137
[983] Staff brief, 147.
[984] DTE reply, 110-111.

this is the first case in which the Commission has had the opportunity to review the full amount of the company's expense projections. The Attorney General explains the history of the pilot:

> Although the genesis of the ACPP/TOU pilot goes back to Case No. U-18255, the Company proposed a pilot program with multiple new rates in Case No. U-20602. However, in that same case, the Commission narrowed the scope of the TOU pilot to only two rate schedules from the Company's proposed six rate schedules.
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> At the Commission's request on October 3, 2019, the Company filed an updated application and affidavit by Camilo Serna with a Revised Attachment A-2 showing that the cost of the Advanced Customer Pricing Pilot would be approximately $7.3 million based on the Company only pursuing testing of two TOU rate schedules. Mr. Serna also referred to additional IT costs presented by Company witness Griffin in Case No. U-20561. On page 32 of his direct testimony in that rate case, Mr. Griffin identified $15.9 million of IT capital expenditures for the Time of Use project. However, that capital cost projection was based on the Company implementing six new rates for the pilot, two Time of Use rates, two Demand rates, and two Hybrid rates (TOU and Demand). This project appears to be much more than the pilot program approved by the Commission in its February 4, 2021 U-20602 order when it approved a delay in the implementation of the pilot.[985]

The Attorney General also takes issue with DTE's response to discovery in Exhibit AG-1.71, contending that the company's pilot and proposed rate design in this case exceed what the Commission directed.[986] Regarding DTE's alternate proposal, the Attorney General argues that DTE's revised proposal was presented too late in this proceeding to be evaluated. She also argues that DTE has not been clear what the total costs of the revised proposal will be, arguing that the original costs shown in Exhibit S-23.01 do not

[985] Attorney General brief, 67.
[986] Attorney General brief, 68.

match the total costs DTE initially projected in this case.[987] The Attorney General reiterates her concern with the overall level of expense in her reply brief.[988]

As discussed in the rate design section below, while some practicality is appropriate to consider in rate design, it is difficult to see the choice determined by cost projections provided by DTE in this case that are not reliable. As noted above, DTE does not provide a breakdown of the components of its cost projections. The business case documents in the record for this project are Schedules N1.279 through N1.282; the first two have 2019 and 2020 costs, which still reference the six pilots DTE initially proposed in Case No. U-20602.[989] The second two relate to 2022 and 2023 costs.

As noted above, the capital cost projections include $4.2 million in contingency, bringing the total cost down to $43 million. DTE has not even addressed the Attorney General's argument that the business case for the ACPP pilots it presented in this case did not reflect the reduced number of rates from six to two. Thus, the objective stated in Schedule N1.279, for a total cost of $16.1 million in capital and $3.9 million in O&M, was to "create 6 new rates for the pilot . . ." Additionally, that expenditure was also supposed to develop a design that "will satisfy strategic goals by allowing rate scalability in the future," as objective number 4. The key objectives also included "effective internal communication and training to Customer Service Operations to ensure a positive

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[987] Attorney General brief, 69.
[988] Attorney General reply, 21-22.
[989] The business case included in Schedules N1.279 and N1.280, which are identical, have been modified from the business case with the same project number submitted in Case No. U-20561, which was Schedule N1.40 of Exhibit A-24 in that rate case docket. The earlier version of this business case had total capital costs of $15.9 million and total O&M of $1.5 million; it is difficult to understand why it would have been altered to reflect different expense levels, with a title change from "Time of Use" to "ACPP/Time of Use," but still not reflect the change in the number of pilots.

customer experience," and "support multiple mediums to communicate rate pilot to customers," as objectives 5 and 6.

To evaluate the Attorney General's claims, it is necessary to look back at Case No. U-20602 to see what the Commission approved. DTE's July 19, 2019 application in that case was accompanied by the affidavit of Camilo Serna. In this affidavit, Mr. Serna presented a total incremental cost calculation of $17.1 million for the proposed six pilots in that case, which included $5.9 million in IT capital expense. Mr. Serna compared this incremental cost, which resulted in a per-customer pilot cost of $977, to a per-customer benchmarking cost of $1,000.[990] He identified an additional $10 million in IT capital, which he distinguished from the $5.9 million "Pilot-specific capital costs," labeling them instead "Pilot costs contributing to full implementation."[991] He testified that "[t]he additional work will contribute to and support full implementation of advanced rates in the future." He also testified: "The total IT capital costs of $15.9 million are included in the testimony of Company Witness Mr. Griffin in Case No. U-20561."[992] Mr. Serna further described the comprehensive work included in the IT capital and O&M costs:

> IT capital and O&M costs support the technical implementation of the rates, supporting metering and billing systems, interfaces with Customer Service, and underlying systems improvements. IT is additionally accountable for the technical creation of new microsites supporting customer communication and Pilot web enrollment. IT upgrades are primarily focused in four areas. Procedurally, all system enhancements and modifications require an analysis of requirements, solution design and execution, and then extensive testing to ensure both that the enhancements and modifications function as intended but also that there are no unforeseen consequences of the changes

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[990] See July 19, 2029 application, Case No. U-20602, Serna Affidavit, paragraph 39.
[991] See July 19, 2019 application, Case No. U-20602, Serna Affidavit, paragraph 33.
[992] Schedule N1.40 of Exhibit A-24 in Case No. U-20561 reflects the $15.9 million capital cost identified by Mr. Serna.

a) Meter management. While DTE has nearly full residential AMI rollout16, the current Itron meter data management (MDM) system is primarily designed for register billing and does not support the broad application of advanced rates. Interval billing, which calculates customer usage on an hourly basis over the billing period, is the more appropriate approach to managing advanced rates. DTE's current residential meters record hourly interval data, but the architecture and logic to translate those values into useful billing determinants has not been developed. The MDM requires enhanced coding and logic to perform two specific tasks. The first is to receive and organize the interval data in such a format that it can aggregate the data and provide the appropriate billing determinates through an interface to the billing system. The second is to create validations that will ensure data completeness from the MDM to the billing system, by replacing all missing register data into off-peak usage.

b) Billing system. DTE uses SAP for billing calculations. The system is currently structured to receive register usage data, apply a rate to that usage, add any additional charges, and calculate a bill. DTE's existing residential TOU rates are processed using the on-peak period sums and then identifying the difference to determine the off-peak usage. This more complicated approach would be more efficient if SAP pulled hourly interval billing data, checked for the on-peak window, and then applied the correct hourly rates. At present, SAP does not have the logic built to do this and requires additional coding to define the routine to request and manipulate interval data. Moreover, assigning demand related costs requires the same interval data, as there is no register-based workaround when the target period is one of many hours across a billing period.

c) Bill presentment. Residential bills are visually organized and presented using OpenText. The software is programmed to pull specific information from SAP and orient it on a page in a certain way based on the information that must be included. While the Pilot TOU-only rates require only minimal changes given the existing bill presentment for TOU rates, the demand-only and combined rates represent new work. Logic must be developed and implemented to both pull the information from SAP but also to arrange it in an easily communicated fashion on the paper bill and online. The latter effort requires modifications to be made to existing bill presentment as certain lines of information may shift based on where the demand rate calculations and charges are placed on the bill.

d) Outreach support. IT will provide technical support for customer outreach, particularly the microsites and web-based customer Pilot enrollment. The seven microsites will require scripting to ensure proper display of videos, graphics, and other content, and contain appropriate redirects to customer single sign on. Web-based enrollment requires IT to develop data routing processes, supported by new code, to ensure that as

> a customer clicks "Enroll" on the website, the information is directed to the correct support resource while maintaining an automatic enrollment appearance for the customer.[993]

Subsequently, after the Commission reduced the number of pilots, it directed DTE to provide a revised cost estimate, referring to the O&M costs of $11.2 million DTE included with its application. As part of the company's October 3, 2019 filing, Mr. Serna provided a revised affidavit that reduced the O&M costs to $7.1 million. Mr. Serna further stated:

> [M]any pilot costs are not variable in nature and therefore do not scale linearly with the number of rates being tested or the number of customers included in the pilot. For example, underlying system enhancements, such as the transition to interval billing, drive incremental IT O&M spending that does not vary with the number of rates or pilot customers. Customer outreach messaging related to pilot enrollment, the application of TOU rates, and other program-specific details must be developed and tested regardless of how many rates are included in the pilot. Reducing the number of rates from six to two has limited bearing on the costs associated with these types of activity.[994]

After reviewing the company's claims in Case No. U-20602, it appears that, even though DTE now contends its 2019 and 2020 capital spending was attributable to the ACPP only, in that case it contended that a substantial amount of the cost would facilitate the implementation of full time of use rates. DTE further indicated that many of the investments needed for the pilot would be needed no matter how many customers were included. DTE has made no effort whatsoever to relate its expense projections in this case to what it accomplished to implement the pilots.

The $35.8 million business case for 2022 and 2023, Schedule N1.281, states eight key objectives, some of which are not fully legible on the form, with no specific

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[993] July 19, 2019 application, Case No. U-20602, Serna affidavit, paragraph 34. Note that the "demand rates" referenced in paragraph c of that affidavit were not part of the approved pilots.
[994] October 3, 2019 filing, Case No. U-20602, Supplemental Affidavit of Camilo Serna, paragraph 14.

costing or additional analysis of any. The 2023 business case, Schedule N1.282, has a different set of objectives from Schedule N1.281:

1) Utilize existing TOU/ACPP Rates. No new rates to be created.
2) The TOU rate will apply only to residential customers.
3) Utilize Usage Graphs built in the Pilot.
4) No changes are required for CEUD. Usage graphs will utilize the Data Lake.
5) Need to explore future infrastructure required to support full implementation.
6) Planned Scope includes: EA, Unbilled Sim, Conversion, Billing &MIMO, Changes to Eligibility Rules, AMI Scalability, Micro Sites, Communication, and Regression.

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

b. Level 1 estimates (B5.7.3, lines 15-16, 19, 29, 41, 54, 56, 58)

For the reasons stated above, this PFD concludes that Staff's exclusion of projected test year expenditures for Level 1 estimates should be adopted for Schedule B5.7.3.

c. Level 2 estimates (B5.7.3, lines 2,4-6, 8-13, 22-27,31, 38, 44-46, 48-49, 53, 55, 57)

For the reasons stated above, this PFD concludes that Staff's reduction to DTE's bridge and test year Level 2 expense projections for Schedule B5.7.3 should be adopted.

d. Automated Application Monitoring Enhancement (B5.7.3, line 21)

Ms. Pizzuti testified that the company is proposing to spend $2.4 million in the bridge period and an additional $0.36 million in the test year to make use of an SAP feature recently added:

> In 2020, the Company invested $0.7 million in capital to implement SAP Solution Manager 7.2, which is described in Witness Sharma's testimony in the instant case, and which included real-time monitoring of the CR&B applications. Utilizing Solution Manager's monitoring capabilities is allowing the Company to identify issues that are impacting the customer experience in real-time, which allows for the more rapid identification, immediate escalation, and improved responses to customer-facing issues. An additional $0.7 million in bridge and test period capital is included in Witness Sharma's testimony to provide funding for the ongoing sustainment of Solution Manager, while my testimony in the instant case includes $2.7 million in bridge and test period capital to enhance the solution and 6 its capabilities.
>
> Expanded capabilities to be implemented during the bridge and test periods includes interface monitoring, job monitoring, user experience monitoring and business process modeling and a central repository of these processes. These enhancements will provide the Customer IT teams the ability to plan, implement, test, operate and enhance business processes more efficiently, with a centralized repository of documentation and data that will assist in root cause analysis and speedy resolution of any production issues.[995]

Ms. Rogers explained Staff's recommendation to exclude the projected bridge and test year expenditures from projected rate base:

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[995] 8 Tr 2182-2183.

> While this Automated Application Monitoring Enhancement might be desirable for the Company to have, neither testimony nor the business case have provided any evidence that it improves the safety and reliability of electric service to customers. In a case with "significant investments in distribution, generation, and customer service," without a benefit to customers, this project falls short of being a prudent expense at this time.[996]

In rebuttal, Ms. Pizzuti testified to cost savings from the project, to show its value:

> This project is expected to improve the up time of our SAP Customer Relationship and Billing (CR&B) system by 1% and reduce unplanned outages by 1%, which equates to approximately $50,000 a year reduction in IT support time to resolve unplanned events.[997]

Staff argues that DTE has not established that this project will improve safety or reliability, citing Ms. Rogers' testimony. Staff considers Ms. Pizzuti's rebuttal regarding billing-system benefits to be new information that does not change Staff's position, noting that Staff and intervenors have not had time to research this claim, and contrasting the $50,000 annual savings to the $2.7 million capital expense.[998]

In its brief, DTE relies on Ms. Pizzuti's testimony.[999] In its reply brief, it further argues that the savings Ms. Pizzuti identified are "consequential (avoided IT support time) and that there is further value in avoiding system downtime, which prevents customers from transacting business with DTE Electric in their channels of choice."[1000]

A review of the business case documents for this project (one for 2021 spending and one for 2022 spending) show a hodge-podge of technical changes, but nothing about any savings and no quantification of any system improvements.[1001] This PFD

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[996] 8 Tr 5354.
[997] 7 Tr 2255.
[998] Staff brief, 110-111.
[999] DTE brief, 133.
[1000] DTE reply, 102-103.
[1001] See Exhibit A-24, Schedules N1.290 and N1.291.

finds that Staff's position should be adopted. DTE has been given multiple opportunities to present quantification of the benefits of its proposed projects as part of its direct case, but such offerings are not persuasive or reliable when offered in rebuttal. It is worth noting that this line item does not reflect a discrete project to improve the CR&B application. Instead, the business cases list multiple "outcomes" and "objectives" that are not the same from year to year, and only incidentally refer to "CR&B." In Schedule N1.290 (the 2021 business case), it is mentioned in one of the business outcomes listed:

> Customer IT will be able to plan, implement, test, operate and enhance business processes more [efficiently]. Centralized repository of documentation and test results will help in root cause analysis and speedy resolution of any production issues. Data footprint in CR&B application can be monitored and managed more effectively with the visibility into the data growth. These capabilities will enable improving the stability and the availability of the applications for customers and end users. Quick to market solutions to realize customer satisfaction.

It is not mentioned at all among the 9 key objectives stated in the document. In Schedule N1.291 (the 2022 business case), the CR&B application is not mentioned in the description of the problem to be solved, or in the system or process being affected; it is mentioned in one of the 6 objectives: "Implement Data volume management to monitor the data growth in CR&B landscape to keep the applications with in the optimum operating conditions." Thus, even if DTE were to realize the claimed savings from this "project," it is not at all clear what the cost of those savings would be, intermingled with the rest of the activities and objectives in these documents.

e. Supporting capabilities test data (B5.7.3, line 30)

DTE projects bridge period expenditures of $914,000 in the bridge period along with $256,000 in the test year. Ms. Pizzuti explained the project as follows:

Currently, the CR&B application team must manually create data in support of the testing of enhancements and new solutions in the Customer IT Portfolio. The manual process is cumbersome, time consuming, error-prone, and can result in excessive levels of retesting. To eliminate these issues, the Company is investing $1.2 million in bridge and test period capital to establish a process to generate automated test data and test scripts using the SAP Tricentis solution – an AI-driven, end-to-end, continuous testing platform.[1002]

Staff recommends that the Commission exclude the projected cost of this project from rate base for reasons similar to Staff's rationale for excluding the automated application monitoring enhancement projects, as explained by Ms. Rogers:

Staff believes the expenditure necessary for implementation of Supporting capabilities-test data and test data mgmt. project would be better spent on the aging electric infrastructure. The Company provides no evidence of safety or reliability benefits in testimony or the business case as a result of this project. This project is another "nice to have," but imprudent to pass on to ratepayers who will receive no benefit.[1003]

In rebuttal, Ms. Pizzuti maintained that there are efficiencies associated with the project:

The Company maintains that this project enables us to increase the efficiency of our IT project testing processes by providing the capacity and ability to perform testing of newly developed IT projects without interrupting other projects that are already in the testing environment. The standard process for putting IT projects into production (i.e., implementation in the live system) requires all projects to be thoroughly tested before they are put into production. This application further automates our ability to perform testing of all systems and software that could be affected by introducing the new IT project into the production environment and ensures there are no adverse effects (i.e., regression testing). Moreover, this application improves the effectiveness of our testing process by providing the ability to incorporate new testing features and testing scenarios, which ensures the completeness of our project testing. These additional testing capabilities improve the throughput of our testing process and ability to meet IT project delivery timelines, and

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[1002] 7 Tr 2185.
[1003] 8 Tr 5355.

> prevent potential defects or issues from occurring downstream of the project.[1004]

In its brief, DTE relies on Ms. Pizzuti's rebuttal testimony, emphasizing the benefits of testing IT projects before they are put in place to avoid adverse effects.[1005] Staff relies on Ms. Rogers' testimony, arguing that the project "may be nice to have," but Staff does not believe the ratepayer benefit justifies the expense, also noting the company's need to repair aging infrastructure.[1006] In its reply, DTE argues that Staff did not respond to the substance of the company's rebuttal.

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

f. Authentication and ID management (B5.7.3, line 33)

Ms. Pizzuti explained the company's projected spending in this category as follows:

> DTE is investing $910,000 in bridge period capital to update its Authentication & ID Mgmt. software, a customer solution that does not conform to current industry norms and limits customer options to authenticate and view their accounts. Customers who have difficulty authenticating often abandon their attempt to self-serve on the web and instead call the contact center. This project will retrofit the digital channels to accept industry open standards such as OpenID or OAuth to authenticate customers and grant access to their profile. Customers will be able to use third-party forms of identification (e.g. Google login, Facebook, biometrics) to more easily access their accounts without sacrificing the security of that access. Easier access, with more options,

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[1004] 7 Tr 2255-2256.
[1005] DTE brief, 134.
[1006] Staff brief, 111.

> will reduce calls to the contact center, increase CSAT for customers attempting to login, and increase web completion rates.[1007]

Ms. Rogers explained Staff's concerns for the security of customer data:

> While the Company states that security will not be sacrificed, the testimony did not elaborate on how the Company plans to protect data, despite opening themselves up to large, third-party sites. Using Facebook, Google log in, and Biometrics unlocks the door for many data access and privacy issues. A password breach or account hack on one of these platforms can unnecessarily impact a customer's DTE account. If Facebook or Google goes down for any amount of time, a customer will also be locked out of their DTE account. Additionally, Staff is concerned about the personal data that can and will be shared between Facebook, Google, Biometrics, and DTE.[1008]

Ms. Rogers also cited Staff's March 25, 2022 report in Case No. U-20959, the MI Power Grid Customer Education and Participation Workgroup, testifying that Staff considers this project contrary to Staff's proposed recommendations that report. Staff's brief reiterates that it does not agree with the use of third-party sites such as Facebook as a way for customers to access their DTE accounts, and is not satisfied with DTE's assurances of security.[1009] As Staff notes, DTE did not file rebuttal to Staff's adjustment; it also did not brief the issue. This PFD concludes the adjustment should be made.

g. Digital Project Groups (B5.7.3, lines 42, 43, and 49)

Ms. Pizzuti included three line items on Schedule B.5.7.3 under the heading "digital product teams." She characterized them as the foundation of three project business cases.[1010] With different names, the spending for each of these groups spans distinct time periods. Line 42 includes the $5.2 million spent in 2020 for the Digital Experience Group (DEG). Line 43 includes the $6.5 million estimated spending in 2021

[1007] 7 Tr 2203-2204.
[1008] 8 Tr 5356.
[1009] Staff brief, 110-111.
[1010] 7 Tr 2192.

for the Digital Transactional Experience. Line 49 includes projected spending of $5.4 for the 10-month bridge period in 2022 and $4.2 million in the test year for the Journey Work Product Transformation Teams.

Ms. Pizzuti testified that DTE "created the first two digital product teams in 2020 to support the improvement of the MIMO and Outage web customer journeys." [1011] She testified that the work on the MIMO web customer journey increased completion rates from 45% to 59%, increased "web engagement rates" from 14% to 19%, and also added on-line MIMO order tracking.[1012] She credited 2020 work on the Outage web journey for enhancements illustrated in a graphic at 7 Tr 2194, a reduction in incorrect outage reporting from 4% to 2%, and an increase in self-service outage completion from 81% to 96.3%.[1013] DTE seeks to recover $5.2 million spent in 2020 for its "digital experience group" program, although the Commission rejected funding for this program in Case No. U-20561.

Regarding the 2021 spending for the Digital Transaction Experience, she further explained the work on MIMO, using a graphic at 7 Tr 2196 and testifying:

> To-date, the MIMO teams 10 have implemented enhancements that have increased engagement rates from 11 19% (2020) to 25% (YTD 2021) and increased completion rates from 59% 12 (2020) to 64% (YTD 2021). Implemented improvements to the MMO web 13 experience are expected to further increase 2021 engagement and completion 14 rates to 38% and 68% respectively, which will be achieved through improved 15 process flows, more information for customers, and a simplified experience.[1014]

[1011] 7 Tr 2192.
[1012] 7 Tr 2192-2193.
[1013] 7 Tr 2193-2194.
[1014] 7 Tr 2195.

Regarding Outage web journeys, she testified:

> [T]he Outage digital product team has continued its focus on improving the Web and Mobile App experience. In 2021, the Outage digital product team further improved the usability, navigation, and usefulness of the Outage web. These efforts resulted to another 1.1% increase in completion rates from 96.3% in 2020 to 97.4% YTD in 2021, which was achieved despite the record number of storms. Additionally, the Outage digital product team launched three new cloud-based sites, upgrading our legacy Police and Fire, Municipalities, and Outdoor Lighting reporting tools to improve simplicity of navigation, overall performance, and the availability of these portals.[1015]

She also credited the 2021 funding for additional work in billings and collections:

> Digital Transactional Experience funding expanded the scope of the MIMO digital product team to include development and implementation of new digital and voice self-service solutions for the MIMO, Billing, and Collection transactions, as well as the development and implementation of a Collection order tracker similar to what they developed in support of the MIMO transaction.[1016]

Regarding the projected expenditures for the 10-month bridge period and test year, she described the work to be undertaken as follows:

> These teams will leverage the digital product team structure and expand the scope to include all five of the highest volume transactional customer journeys – MIMO, Outage, Collection, Billing, and Payment.[1017]

She further described the planned two-year effort to "enhance, design, and implement" self-service options for collection activities:

> Over the course of the next two years, customers who need assistance with their bill, or who have been disconnected for non-payment, will have the ability to request a promise-to-pay hold, enroll in a payment arrangement, process a restore, and validate their low-income status on the web and in the [Interactive Voice Response] IVR.[1018]

[1015] 7 Tr 2197.
[1016] 7 Tr 2196-2197.
[1017] 7 Tr 2197-2198.
[1018] 7 Tr 2198.

She considered this work would promote customer satisfaction, assist customers to stay current and minimize outstanding balances, and reduce calls to the call center. Regarding billing and payment, she testified:

> The Billing/Payment digital product team will identify opportunities and implement solutions to enhance the web experience by (i) improving the look and feel of the billing and payment pages, (ii) enhancing the view and clarity of payment information, the current bill, prior period bills, and comparisons between current and prior period bills, (iii) deploying targeted banner messages (e.g. relevant programs, energy savings tips) based on these bill views and comparisons, (iv) automating the currently manual high bill alerts, and (v) providing web presentment of real-time usage data, which today is only provided in the form of hourly data via the download of CSV or XML file. These improvements will provide customers simple and convenient web solutions that will allow them to better analyze their usage and bill amounts.[1019]

Ms. Armstrong explained Staff's recommended 60% reductions to the 2020 and 2021 spending. Specifically regarding the digital experience group 2020 expenditure, Ms. Armstrong referred to Staff's view, reviewed above, that core customer concerns are for reliable, affordable electricity, correct meter reading, and accurate billing, and further explained:

> The purpose stated by the business case executive summary for the Digital Experience Group is "to surprise and delight our customers by delivering a seamless digital experience our customers deserve, setting the bar outside our industry for best practice. To approach this properly, we need to transform the way we work by eliminating the silos and creating a cross-functional team (Digital Experience Group/DEG) to drive the vision, roadmap, and implementation of the next generation DTE digital customer experience" (Business Case, Company Exhibit A-24, Schedule N1.344, pp. 51-52). While 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.[1020]

[1019] 7 Tr 2199.
[1020] 8 Tr 5493.

Ms. Armstrong discussed Ms. Pizzuti's testimony regarding improved outage reporting accuracy and increased completion rates for move-in move-out transactions.[1021] She further explained Staff's conclusion that the company had not supported this expenditure, noting other company expenditures also designed to achieve the same results:

> Company witness Pizzuti provides self-service engagement rate goals across channels increasing from 59% to 75% by 2025 and self-service completion rates increasing from 59% to 74% by 2025, with an estimated reduction of 1.2 million calls to the contact center through 2025 and a savings of $7 million O&M cumulative through 2025 (Company witness Pizzuti Testimony, pp. 61-62). However, the Company spent $5,183,000 in capital expenditure in the historic year alone for the Digital Experience Group, just one element needed to increase digital and voice engagement and completion rates. The Customer Closed Loop Journey line item is another project in the historical year that developed the tools to increase engagement and completion. The Company spent $3,010,000 in capital in the historical year and proposes capital expenditures of $2,951,000 in the bridge years and $2,453,000 in the proposed test year (Company Exhibit A-12, Schedule B5.7.3, line 17 38). The combined capital amount of just the Digital Experience Group and the Customer Closed Loop Journey that DTE has invested and seeks to invest is $20,046,000 over the historical, bridge, and test years. Again, the benefits do not justify the substantial costs.[1022]

Recognizing the Digital Transactional Experience as a continuation of the Digital Experience Group, she explained Staff's conclusion that the company had failed to show how the expenditure would accomplish the goals at a reasonable cost. Addressing the company's forecast increases in customer satisfaction, "self-service engagement rate," and "self-service competition rate," and its forecast decrease in calls to the call center, she cited company audit responses in Exhibit S-24 and explained:

[1021] 8 Tr 5494-5495
[1022] 8 Tr 5495.

> The Company has based forecasted improvements on prior experience and not on a specific data study and did not respond to a request to explain the forecast of 1.2 million call reduction to the contact center . . . . Again, Staff questions the prudency of spending $6.45 million in the projected bridge period for the Digital Transactional Experience line for these forecasted goals when the Company has not provided underlying data on how they will reach already high increased rates of completion and satisfaction, nor will the Company reduce costs for the customer.[1023]

In addition to a concern with the diminishing value of additional investments targeted and increasing already high rates of completion and satisfaction, she noted numerous other line items in the company's expense projections focused on similar goals:

> It is unclear how the Company ties the Digital Transactional Experience expenditure with other work streams in discretionary Customer service IT, such as the Closed Loop Customer Journey line, the Error Free Communication line, the IVR Virtual Assistants line and the IVR National Language line, the Journey Work Product Transformation Teams, and the Kiosk experience line, all of which are related in some way to the Digital Transactional Experience expenditure (Company witness Pizzuti, Company Exhibit A-12, Schedule B5.7.3). For example, for the Closed Loop Customer Journey line (2021, 2022, 22 2023), the Company states it "will develop Closed Loop customer journeys across the highest volume customer transactions. This investment started with the MIMO transaction in 2019, has been expanded in 2021 to include the Collection transaction, and will be expanded further in 2022 and 2023 to include the Billing & Payment transactions." The Closed Loop Journey line is also referenced as a focus in the Digital Transactional Experience expenditure (Company witness Pizzuti Testimony, p. 69). There is no reference to the Digital Transactional Experience expenditure with the business case or testimony for the Closed Loop Customer Journey Development, nor mention of the Digital Transactional Experience in the business case or Company witness Pizzuti's Testimony (Company witness Pizzuti, pp. 45 – 47). These two expenditure lines are focused on similar goals; however, the Company does not associate them in testimony or the business case. It is also not apparent how the Error Free Communication expenditures (2021, 2022), which consist of a cross-functional team of employees from across the Company (who are engaged in an evaluation of all the core systems, subsystems, and system integrations that work together to monitor and manage outage restorations, repairs, estimates, and customer communications), the Customer Digital Channels and Self Service

[1023] 8 Tr 5496-5497.

> Program (2022), and the Journey Work Product Transformation teams (2022) that work in concert with each other.[1024]

Regarding the Journey Work Product Transformation Teams, Staff's recommendation was to adjust the spending for both the ten-month bridge period (2022) and projected test year spending by 20% to reflect the company's Level 2 cost analysis.[1025]

Mr. Coppola did not address the 2020 spending, but recommended that the Commission reject the spending for 2021 through the projected test year. He considered Digital Transaction Experience and Journey Work Product Transformation Team costs as lacking sufficient support for inclusion in rate base. Specifically focusing on the Digital Transaction Experience in line 43, he considered these 2021 expenditures as intended to address inadequate work in 2020:

> The Digital Transactional Experience entails $6,450,000 of capital expenditures in 2021. This project appears to be a continuation of work initially done in 2020 to fix the Move In/Move Out (MIMO) digital system that allows customers to process their service termination or service start through a self-service option through digital channel when changing service locations. When first implemented the MIMO system did not work properly and customers were frustrated and could not always complete the desired service transfer. On page 43 of her testimony, Ms. Pizzuti discusses the work done in 2020 to fix the systems under the MIMO DEG project name. As it continued with further work and expenditures into 2021, the Company changed the name of the project to Digital Transactional Experience and proposed to spend an additional $6.5 million.[1026]

Citing discovery responses provided by the company in Exhibit AG-1.23, Mr. Coppola testified:

> In discovery, the Company was asked to explain why additional enhancements are still necessary to this system. In response, the Company identifies features that are rather basic to the operation of the

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[1024] 8 Tr 5497-5498.
[1025] See Exhibit S-12.4, page 1.
[1026] 8 Tr 4809.

> system that should already have been addressed in earlier stages of the overall project. Other listed improvements are vague and difficult to ascertain as to their necessity and value added.[1027]

He noted the company's connection between this project and the Journey Work Transformation Teams, but as discussed below, did not consider that project to be economically justified either, focusing on Ms. Pizzuti's testimony regarding the additional focus on collections and billing and payment:

> The discussion on this project beginning on page 48 of Ms. Pizzuti's direct testimony addresses two component projects the Collection Journey Work Product Transformation Team and the Billing/Payment Journey Work Product Transformation Team. The first appears to be a means for customers to extend the payment due date as a self-service without having to discuss their request with a customer service representative. This appears to be an invitation to higher uncollectible costs not less. The second project appears to be an undefined project where the digital product teams will find opportunities to "enhance the web experience." It seems that nothing specific has yet been identified for this project to provide any value added. If both projects are directed at reducing customer calls, it would seem that an economic case should be made as to whether the cost savings justify the capital expenditures to develop more digital systems and features. However, as stated earlier the Company has not performed that financial justification.

Ms. Pizzuti provided rebuttal to Ms. Armstrong's recommendations at 7 Tr 2257-2267. Ms. Pizzuti testified that the company had done benchmarking with peer utilities regarding its digital offerings, citing Schedule II1 of Exhibit A-44 and discussing learnings from that benchmarking.[1028] She characterized Ms. Armstrong as testifying that "customers are not concerned with alternate technologies,"[1029] and disagreed with

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[1027] 7 Tr 4810.
[1028] 7 Tr 2258-2260.
[1029] 7 Tr 2260, citing Armstrong, 8 Tr 5490. Technically the characterization is in the question rather than the answer, but it clearly misstates Ms. Armstrong's testimony that customer concerns "mainly" lie with reliability, cost of service, meter reading, and accurate billing.

the assertion. Referencing Schedule II1, she defended the general concept of utilities investing in digital technologies:

> Our decisions to invest in what Staff Witness Armstrong considers as "Alternative Technology Projects" are part of a larger trend in the utility industry toward self-service and amongst our utility peers.

She testified that DTE's self-service rates for 2019-2020 ranked in the third quartile among peer utilities, citing Exhibit A-44, schedule II2:

> DTE's Self-Service rate has been increasing from 76.8% in 2020 and to 81.2% in 2021. Yet, the Company has ranked in the third quartile in both years as compared to our utility peers in the study. Our 2021 results of 81.2%, if accomplished in 2020 would have put the Company at the bottom of the second quartile (80.2%). In 2021, second quartile performance would have meant increasing our Self-Service rate to 84.4%. So, the bar keeps rising every year. Additionally, we see that top quartile ranking companies have not only higher Self-Service rates, but also have a larger proportion of their self-service contacts via the web or mobile app.[1030]

She testified that these benchmarking results show customer preferences to interact digitally, and "supports our investment decisions to add more self-service transactions to the web and our digital channels overall."[1031] Ms. Pizzuti continued to address what she considered Ms. Armstrong's "questions related to the outcome of the DEG project." She testified to the benefits from the MIMO digital product teams in 2020,[1032] and regarding the outage investment in 2020, she responded to Ms. Armstrong's concerns regarding diminishing returns by asserting that the company also believes its investments are about customer satisfaction.[1033] In that context, it should also be noted that Mr. Sparks also addressed what he characterized as Ms. Armstrong's testimony

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[1030] 7 Tr 2260-2261.
[1031] 7 Tr 2261.
[1032] 7 Tr 2262-2263.
[1033] 7 Tr 2263.

that there is a finite level of customer satisfaction that can be achieved in a captive market.[1034]

Regarding the 2021 expenditures, she reiterated that the 2021 expenditures are a continuation of the 2020 project “and builds on its success,” with continued funding for MIMO and outage areas and expanding into billing and collection, further discussing each.[1035] Regarding MIMO, she testified: “We have seen higher customer satisfaction as measured by Net Promoter Score (NPS) from 62 to 72 from 2020 to 2022 YTD and First Contact Resolution (FCR) of 84% to 91% from 2019 to 2022 YTD.”[1036] Regarding the outage piece, she testified that the company is continuing to improve “the customer’s outage experience” and “completion rates” despite the record number of storms in 2021, while acknowledging “most of the Digital Product Team resources were dedicated to improving MIMO and expanding the scope of their work to include implementing voice self-service and digital options for the collections transaction.”[1037] For collections, she discussed an tracking capability for 2021, an integrated voice response (IVR) for the Collections Promise-to-Pay (PTP) and Restore Service programs, as well as a virtual assistant (VA) for collections.[1038]

Ms. Pizzuti also addressed Ms. Armstrong’s reference to the company’s decision to hire an additional 400 customer service representatives, citing the company’s explanation in a discovery response included in Exhibit S-24, as well as Mr. Spark’s rebuttal testimony at Tr 1642-1644.

[1034] 7 Tr 1647, citing Armstrong, 8 Tr 5490. Ms. Armstrong actually testified to finite level “that can be reasonably achieved.” Again, the characterization of her testimony appears in the question.
[1035] 7 Tr 2264-2266.
[1036] 7 Tr 2265.
[1037] 7 Tr 2265.
[1038] 7 Tr 2265-2266.

Responding specifically to Mr. Coppola's recommendations, she took issue with what she considered his refusal to appreciate the company's prioritization score method:

> It appears that Witness Coppola considers the Company's Project Prioritization Score (PPS), that is used by the Company in place of a traditional benefit cost analysis, as insufficient information to justify the capital expenditures being requested for these two digital projects. As shared in my answer to AG discovery question AGDE-8.286d and AGDE-8.286e (See AG Exhibit AG-1.23 pages 3-4), and 8.288c (See AG Exhibit AG-1.23 page 7), the Company uses the PPS score because it evaluates an IT capital investment across multiple business benefit categories in addition to cost. Since the PPS is used to assess one IT investment against another and for prioritization across the DTE IT investment portfolios in a consistent manner, it is a critical component of the Company's IT Annual Planning Cycle (APC) process that we began applying to IT projects beginning in 2022.[1039]

She also noted that the company provided a projection of cumulative call reduction volume and associated O&M cost reductions "expected from our investments in the Digital Product Teams and the IT digital transformational projects they support such as DEG, Digital Transactional Experience, and Journey Work Product Transformation Teams."[1040] She cited Exhibit AG-1.23, page 9, and Schedule II5 of Exhibit A-44, which she identified as a supplemental attachment to that discovery response and to a Staff audit question, containing the company's "most recent forecasted cumulative call reduction of ~1.2 million calls from six transactions."[1041]

In its brief, Staff argues that Ms. Armstrong's recommendations should be adopted.[1042] Staff explains its general concerns with the company's Digital Product Teams, that it appears duplicative with other projects the company is proposing,

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[1039] 7 Tr 2271-2272.
[1040] 7 Tr 2272.
[1041] 7 Tr 2272.
[1042] Staff brief, 121-126.

including additional capital expenses for Customer Relationship and Billing Program enhancement, Customer Experience Suite, Web Transformation, Bill management, and the IVR Assistant program, among other programs.[1043] Staff also compares the company's total projected O&M savings of $7 million over the years 2022-2025 as "significant, . . . [but not] nearly enough value to the ratepayer to justify the cost."[1044] Staff also cites Mr. Coppola's testimony at 8 Tr 4808-4809, stating that DTE could not provide tangible benefits and cost savings or other information to economically justify the large capital expenditures. Staff argues:

> Company witness Pizzuti has not demonstrated that the Digital Product teams should be funded outside of digital projects that are also requested for recovery and has not established value for the customer provided for these teams.[1045]

The Attorney General argues that the Commission should exclude the 22-month bridge and test year costs as recommended by Mr. Coppola. Addressing the company's rebuttal, the Attorney General notes the company's projected reduction in call volume, but argues that the company has not made any effort at a financial justification for the spending. The Attorney General cites Exhibit AG-1.71 as another discovery response confirming that DTE did not perform a benefit cost analysis for this spending.

DTE disputes Ms. Armstrong's testimony that customers are more concerned with reliable, affordable electricity, correct meter reading, and accurate billing by citing utility benchmarking to show that customers care about being able to use digital channels to transact business with the company.[1046] It also argues that the company's

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[1043] Staff brief, 123.
[1044] Staff brief, 125.
[1045] Staff brief, 124.
[1046] DTE brief, 134.

work on its digital channels led to call reductions, improved outage web experience, and more accurate outage reporting, "justifying their full cost recovery."[1047] It further responds to Ms. Armstrong's concerns with the cost of the 2021 projection by arguing that the 2021 digital transactional experience builds on the success of the 2020 project, also emphasizing Ms. Pizzuti's rebuttal testimony as discussed above.

DTE similarly responded to the Attorney General's recommended disallowance of the 22-month bridge and test year costs of the Digital Transaction Experience and Journey Work Product Transformation Teams. DTE argues that it uses the project prioritization score in place of a traditional cost benefit analysis "and is a critical component of the Company's IT APC process." It also argues that it provided a projection of cumulative call volume reduction and associated O&M cost benefits in discovery, citing Exhibit AG-1.23, page 9, as well as Schedule II5 of Exhibit A-44, "a supplemental attachment that was provided in response to Staff audit question CR-1.2."[1048]

This PFD finds that the 60% of the 2020 spending on line 42 should be disallowed as recommended by Staff, while the remaining estimated 2021 expenditures and projected bridge and test year expenditures on lines 43 and 49 should be rejected as unsupported. This PFD notes that Staff's adjustment to line 49 removed 20%, which this PFD adopted above, so that leaves the remaining 80% that this PFD finds should be excluded from rate base. Although duplication or overlap between the company's spending through this program and myriad other programs targeted at the company's

[1047] DTE brief, 135.
[1048] DTE brief, 141.

web page, customer journey, and digital transactions was raised as a concern in Case No. U-20561, and although Ms. Armstrong explicitly and Mr. Coppola to a lesser extent raised that concern again in this case, DTE made no effort to establish the specific additional contributions from the spending on these teams. Although Ms. Pizzuti attributes all the benefits she described in terms of increased web access or self-service transactions, she did not identify, let alone separate all the additional money DTE has spent on its web and self-service programs, nor did she establish that the "achievements" for these teams are directly attributable to any additional spending by DTE, rather than, as she identified, increasing customer interest in digital transactions. As the Attorney General argues, DTE did not present a benefit cost analysis for any of this spending. DTE relies on its prioritization score as a substitute for a "traditional benefit cost analysis." As discussed above, the company's prioritization formula is not transparent; DTE may choose to rely on it, but that does not establish that it is a reliable substitute for the traditional Commission prudency review, which looks at such items as quantifiable benefits. The one glimpse DTE afforded into this prioritization process it uses is displayed in Exhibit AG-1.71. There, DTE shows that it assigns "benefit/cost" a score of 1 out of 10, and assigns "customer satisfaction" a score of 9 out of 10; other seemingly subjective scoring is also shown for the remaining elements (although how the determination was made regarding that scoring is not explained), resulting in a prioritization score of 5.6. DTE does not put this score in context, but on a scale of 1 to 10, 56% is not that compelling. DTE further acknowledges that it has no scoring for 2022 expenditures, which includes the 10-month bridge period and a portion of the test year. As discussed initially regarding DTE's customer service-strategic spending, Staff has raised significant concerns regarding the company's prioritization of these investments relative to investments in system reliability, for example. DTE's prioritization model does not purport to compare IT strategic investments to other strategic investment opportunities. Although this PFD concludes that DTE has failed to justify any of the spending on these line items, this PFD acknowledges that no party has sought a full disallowance of 2020 expenditures, and finds that Staff's recommendation to disallow 60% of the 2020 expenditures is the appropriate result.

h. Platform integration – SAP integration business (B5.7.3, line 51)

Ms. Pizzuti described the company's projected $1.8 million bridge and $0.5 million test year capital spending as intended to "redesign and optimize how [DTE] engaged with [its] core systems" to manage data:

> Integration Bus works in partnership with API gateway and layer to increase satisfaction, completion rates, and simplify the digital experiences, to do so we need to simplify and change the way we access data in our core systems which ultimately will make our transactions more resilient and available to our customers. Redefining when, and what data is required from the core systems will help us provide billing data, account balance etc. without significantly taxing our core systems.[1049]

Ms. Rogers explained Staff's recommendation that the Commission exclude the projected costs for this project, characterizing the company's business case as incomplete because the company did not identify benefits to customers in terms of savings, safety, or reliability. She also noted the company's failure to consider alternatives:

> [T]he Company did not identify any alternatives considered for this investment. Staff believes a wide range of alternatives should be researched to obtain the most worthwhile solution before a decision is

[1049] 7 Tr 2203.

> made and a cost is requested. This due diligence demonstrates a dedication to making the best investment. Without this information, Staff cannot analyze if this is a prudent expense to include in rates. lacking an analysis of alternatives.[1050]

In rebuttal, Ms. Pizzuti asserted the benefits of the project are related to the company's digital experience group and digital transactional experience projects, discussed above:

> The Company maintains that the benefits and value from the Platform Integration Project are best described in its name, integration. It provides integration between the SAP systems (in the back-end) and many of our Customer Service IT projects that provide an enhanced or new customer experience in our digital channels (i.e., front-end, and customer-facing system or technology.) This project supports the improvements and functionality added by projects such as Digital Experience Group and Digital Transactional Experience, both of which are discussed in detail in my testimony in the instant case, and which I will further discuss in a subsequent portion of this rebuttal testimony. All front-end customer experiences where data is collected, including interacting with a customer service representative (CSR) in our Contact Center, require integration and a connection to the back-end SAP customer systems (e.g., SAP Customer Relationship Management (CRM) system and SAP back end I-SU system where the data is processed and stored). As far as providing evidence that alternative solutions were considered, the SAP application is the best solution since these technology products are intended to work together seamlessly. Migration of functionality and capability from disparate legacy systems or applications to a single SAP platform allows information from our operations and other areas to flow to front-end systems that directly serve the customer.[1051]

In its brief, Staff maintains that the company did not explain how this investment will benefit customers, noting that they will still receive their billing data and account balances without this investment. Staff cites Ms. Rogers' testimony and also references Ms. Armstrong's concerns with the Digital Project groups, discussed above.[1052] DTE

[1050] 8 Tr 5353.
[1051] 7 Tr 2253-2254.
[1052] Staff brief, 108-109.

argues that “the project’s benefits and value are reflected in its name – integration.”[1053] It then reiterates Ms. Pizzuti’s rebuttal testimony. DTE’s reply brief also presents the same explanation.[1054]

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

i. Pre-pay (B5.7.3, line 52)

Ms. Pizzuti considered this pre-pay program as the company’s plan to meet its fourth strategic goal, “develop customer centric rate products & programs.” She discussed the pre-pay program at 7 Tr 2233-2235, but acknowledged that DTE has an application pending regarding the program in Case No. U-21087. Staff and the Attorney General objected to including the company’s projected expenditures for this item. Noting the ongoing separate case, Ms. Armstrong testified that until DTE receives approval of its request for a waiver of the Commission’s Consumer Standards and Billing Practices for Electric and Natural Gas Service Rules and approval for its proposed tariff offering, it cannot move forward with the project.[1055] Mr. Coppola also explained his objections to the proposed program as associated funding.[1056]

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

[1053] DTE brief, 133.
[1054] DTE reply, 101-102.
[1055] Armstrong, 8 Tr 5492-5493; Coppola,
[1056] 8 Tr 4805-4808.

j. Projects with no business case (B5.7.3, line 60)

Ms. Rogers identified several projects for which DTE did not present a business case, including one project on this schedule with total projected bridge period expenditures of $325,000 and test year expenditures of $35,000. Mr. Sharma explained that DTE mistakenly thought the project sizes were below the threshold for requiring a business case document. Although DTE agreed with other similar projects lacking a business case, DTE asks the Commission to approve this project, MIGP-Integrate DTE Insight.[1057] Mr. Sharma presented a business case document for this project in rebuttal, Schedule GG1 of Exhibit A-40. In its brief, Staff argues:

> While Staff appreciates the information, updating a project in rebuttal does not allow Staff and intervenors adequate time to thoroughly evaluate for reasonableness and prudency. As a result, Staff recommends a disallowance of all 5 projects without business cases.[1058]

Staff also cites the Commission's order in Case No. U-20940, the last rate case for DTE Gas Company, arguing that the Commission agreed with Staff that it was too late in the proceeding to evaluate the business cases DTE submitted in rebuttal. Based on Staff's analysis, this PFD finds Staff's adjustment excluding the expense projections for this item as shown in Exhibit S-12.7 should be adopted.

6. Plant and field projects (B5.7.4)

a. Level 1 estimates (B5.7.4, lines 6, 15, 18, 24, 25, 34, 36-38)

For the reasons discussed above, Staff's exclusion of Level 1 estimates for the projected test year should be adopted.

[1057] DTE brief, 127.
[1058] Staff brief, 117.

b. Level 2 estimate (B5.7.4, lines 1, 4, 8-9, 11-13, 16, 19, 21-22, 33)

For the reasons discussed above, Staff's reduction to the 10-month bridge period and test year for Level 2 estimates on this schedule should be adopted.

c. Capitalization (B5.7.4, lines 2, 3, 5, 31)

Staff recommended adjustments to line items on Schedule B5.7.4 for the following projects: ClickSoft Application Health, Distribution Operations Application Health, Fuel Supply Application Health, and FERMI Enhancements, based on Staff's concern that DTE is improperly capitalizing what should be O&M expense. Dr. Wang explained Staff's concern, citing DTE's capitalization policy in Exhibit S-7.17, and referencing her earlier testimony regarding technology and automation capital expenses within the distribution system capital expense category.[1059] She testified that IT upgrades and system enhancements should be expensed unless they add significant additional functionality, result in new software design or an alteration of existing software design, and exceed the $10,000 threshold. She also testified that certain data management costs can be capitalized only with a specific Commission order. She testified that the ClickSoft project focuses on support and enhancements of an installed system, the distribution operations project focuses on "small enhancements and modifications," the fuel supply project focuses on "managing improvements to the Automated Rail Receipts database and sustaining the application overall," and the Fermi project includes "developing data mapping strategy, importing and loading data into the new platform."[1060] For these reasons, Dr. Wang testified, the costs should be

[1059] 8 Tr 5227-5230.
[1060] 8 Tr 5228-5229.

excluded from rate base.[1061] Staff transfers a significant portion of these costs to O&M, with the difference attributable to reductions to the overall cost estimate based on historical underspending as explained by Dr. Wang.[1062]

In rebuttal, Ms. Uzenksi disputes what she considers Dr. Wang's "assumption" that the costs for the first three of these projects are for "maintenance," while instead they add functionality. Regarding ClickSoft, she testified:

> The ClickSoft project includes both minor enhancements and programing changes that add significant functionality. The minor enhancements will be expensed to O&M as incurred and are not reflected in the capital forecast. The specific programming changes that add significant functionality will be identified in the third quarter of 2022 and only the upgrades/costs that agree with DTE's policy will be capitalized.[1063]

Regarding the DO Application Health project, she identified what she contended are examples of added functionality: "[i]ntegrated key DO legacy applications with new ADMS system;" "[r]e-platform legacy applications to enable expansion of new features and functions, systems supporting primary services (PSO) and outage restoration (OSA);" "[p]urchased hardware and servers to support re-platform initiatives (PSO and OSA);" "[u]pgraded power engineering software (CYME) to utilize features provided in newer version of software and account for new data attributes from ESRI system upgrade;" "[a]dded new database instances to Vegetation Management solution to support expansion of Tree Trim activities;" "[r]e-designed Job Package Generator to streamline the creation and distribution of job packages to field crews;" "[a]dded functionality to enhance the user experience of the outage management mobile (OSA) solution," with "[i]mproved filtering and search capabilities;" "[d]esigned, developed, and

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[1061] 8 Tr 5229-5230.
[1062] 8 Tr 5234-5235.
[1063] 7 Tr 2794.

implemented features in Inservice for follow-up work, and integrated with work management (Maximo) for planning and scheduling;" and "[u]pgraded VPN access for Tree Trim Contractors to enable seamless access to Vegetation Management solution(s) for scheduling, dispatching, and completing jobs."[1064] For Fuel Supply Application Health, she identified the following "various enhancements;" "[a]utomated processing of Fuel Quality information;" "[a]utomated processing of PET Coke fuel invoices;" "[i]mplementation of replacement software to integrate coal train car location information into the Automated Rail Receipt (ARR) application;" "[f]unctionality to validate Oil Fuel surcharges on invoices for each vendor and plant;" and "[i]nvoice calculation logic for gas fuel invoices."[1065]

For the Fermi enhancement, she testified:

> The data migration efforts (importing and loading data into the new platform and validating data) while part of the project, have been appropriately accounted for as an O&M expense. Developing the data mapping strategy is considered part of the design phase of the project; without it the software would not be able to be used.[1066]

Staff argues that the Commission should adopt the disallowances recommended by Staff for all four project lines. Staff acknowledges Ms. Uzenski's rebuttal testimony, and does not find it persuasive. Regarding Clicksoft, Staff focuses in on Ms. Uzenski's testimony that the company has not yet identified the significant functionality that the funding will be used for.[1067] Regarding the Distribution Operations Application Healthy, Staff argues that the cited examples do not qualify, citing specifically incorporating data, coding for data retrieval, data updates, filtering and search capabilities should be

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[1064] 7 Tr 2794-2795.
[1065] 7 Tr 2795.
[1066] 7 Tr 2796.
[1067] Staff brief, 129.

expensed. Regarding the Fuel Supply project line, Staff argues that it is difficult to determine whether these meet the requirements, given the limited time for Staff review following rebuttal. Regarding the Fermi enhancement line, Staff argues that DTE has not provided a breakdown of the costs associated with data migration efforts and the classification of those costs.[1068]

In in its brief, DTE argues that Ms. Uzenski explained that the charges that are capitalized provide new functionality that did not exist previously, and DTE reviews some of the examples she provided.[1069] DTE's reply brief argues that "Staff does not substantively respond to the Company's discussion of the evidence."[1070]

This PFD finds a legitimate basis for Staff concern. While following the presentation of her lists, Ms. Uzenski concludes that "[s]ince these projects result in significant additional functionality, they meet the criteria to be capitalized," she did not assert that any specific item constituted significant additional functionality. Many of these descriptors use terms like "upgrade" "improve" and "enable," which do not convey any particular level of significance, and Ms. Uzenski certainly did not explain any such significance. Mr. Sharma also did not explain any of these items as providing "significant additional functionality." Even if some of the activities should be considered significant, which cannot be determined from her testimony, Ms. Uzenski did not address the second prong of the requirement for capitalization as explained by Dr. Wang, that the expenditures result in "new software designs or a change to part of the existing software design."

[1068] Staff brief, 130.
[1069] DTE brief, 128-129.
[1070] DTE reply, 97.

While Staff argues it did not have time to evaluate the cited Fuel Supply Application Health activities, this PFD notes that the business cases for that line are in Schedules N1.86 through N1.89, and the descriptions of the activities in those documents focus on “support,” “sustainment,” “patches and upgrades,” “updates,” and “implementation of quarterly vendor releases.”

Also troubling, regarding ClickSoft in particular, is that DTE has not yet identified the projects that qualify for capitalization, raising a significant question as to how it could project the capital expenditures in the first place. As discussed elsewhere in this PFD, DTE has provided little information regarding its cost projections for IT, frequently including multiple objectives and not providing cost projections separately for those. Tellingly, as Staff argues, DTE did not provide the accounting for any of the cited projects to show that all capital and O&M expenses associated with that project were properly capitalized in 2021, for those line items with 2021 spending, or provide a breakdown of its projections to show the capital and non-capital activities for the bridge period and test year included in the project objectives.

Given the limited support DTE provided for its IT capital expenditures generally, this PFD recommends that the projections identified by Staff be excluded from rate base, but rejects Staff’s adjusted O&M transfer. DTE will capitalize what it decides can be capitalized of the future bridge period and test year expenses, and providing the funding in O&M will not prevent that.

d. Projected vs. historical (B5.7.4, lines 7, 10, 35)

Dr. Wang looked at the company’s 2020 actual expenditures for certain projects compared to its projected expenditures, and recommended a reduction of $59,000 in the 2021 expense estimate for Nuclear Generation Business Systems Replacement on line 7, and a reduction of $1.4 million to the 2021 expense estimate for the Plant & Field Document Repository project on line 35.[1071] As shown in Exhibit S-7.46, Dr. Wang calculated that DTE spent approximately 91% of its 2020 expense projection from the last rate case for the Nuclear Generation Business Systems Replacement, and 34% of its 2020 expense projection for the Plant & Field Document Repository project, and adjusted the company's 2021 spending projections accordingly. She recommended adjustments only in the 2021 expenditures in recognition of Staff's Level 2 adjustments to the bridge and test year projections for these line items.

For the Service Suite Field Management Product Improvement project, as shown in Exhibit S-7.46, Dr. Wang calculated that DTE spent only 34% of the amount it projected it would spend in Case No. U-20561. Dr. Wang recommended corresponding reductions to the 2021, 10-month bridge period, and test year projections on line 10 of $19,800, $247,782, and $69,373, respectively.

In rebuttal, Mr. Sharma objected to the disallowance, testifying that "[t]his extrapolation is unnecessary because these projects are in progress, [and] the cost estimates are very detailed and are commensurate with the scope of work being completed." He also looked at the group of projects Dr. Wang considered as part of her historical analysis, which included these two line items and others, and as shown in Schedule GG4 of Exhibit A-40, testified that "the combined spend for these sample set of projects used as the basis of calculation/disallowance was well above the

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[1071] 8 Tr 5230-5232.

Company's projected spend of $8.16 million," totaling $12.3 million.[1072] DTE relies on Mr. Sharma's rebuttal testimony in its brief.[1073]

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

e. DERMS implementation (B5.7.4, line 27)

Dr. Wang addressed the company's projected spending for this line item. As discussed above, DTE acknowledged that the projected cost in this line item duplicated costs for a line item in the distribution operations capital expense projections. DTE indicated that it preferred the adjustment to be made to the IT line item rather than the distribution line item. As discussed above, Staff objected, considering its recommended adjustment to this line item best addressed in the context of its other IT adjustments.

Dr. Wang then explained that Staff recommends excluding the projected bridge expenditure of $1.3 million and the projected test year expenditure of $364,667. She testified that DTE has not selected a vendor for Phase I of its project, "indicating that it is in the preliminary project stage for this project, the costs of which are not eligible for

[1072] 7 Tr 2139.
[1073] DTE brief, 131.

capitalization per DTE Energy accounting policies."[1074] She further testified that DTE provided no information on the actual costs spent in 2021 on this project.

Although Mr. Sharma objected to Staff's capitalization analysis, Ms. Uzenski did not directly address this line item in her rebuttal. As Staff argues in its brief, DTE mistakenly considered that Staff had double-counted its adjustment for DTE's own duplication of these costs. In its reply brief, DTE argues that Staff wrongly assumes that the company's capital projections for software development include costs that must be expensed: "Even if the DERMS project is currently in a preliminary stage, the Company's capital request reflects only those costs properly capitalizable (i.e. starting with the development stage)."[1075] DTE cites Ms. Uzenski's testimony at 7 Tr 2793. Based on DTE's assertions that the capital expenditures in its projection for this line item are only intended to reflect the development stage, this PFD concludes the expense projection should be rejected because it is premature for DTE to project the development stage costs when it is still conducting a preliminary analysis.

f. Projects with no business case (B5.7.4, line 40)

Ms. Rogers identified several projects for which DTE did not present a business case, including three projects on this schedule with projected test year expenditures totaling $867,000. As noted above, Mr. Sharma explained that DTE mistakenly thought the project sizes were below the threshold for requiring a business case document. DTE agrees with Staff's adjustment regarding the projects in the plant & field category as shown on Exhibit S-12.7, page 6.[1076] Therefore, this PFD considers this issue resolved.

[1074] 8 Tr 5233.
[1075] DTE reply, 98.
[1076] DTE brief, 127.

7. Information technology for IT (Schedule B5.7.5)

a. Level 2 estimate (B5.7.5, lines 1, 4, 8-9, 11-13, 16, 19, 21-22, 33)

For the reasons discussed above, this PFD concludes that Staff's Level 2 adjustments should be adopted for Schedule B5.7.5.

b. GRC tool expansion for regulatory assets (B5.7.5, line 7)

Mr. Sharma described the expenditures the governance risk and compliance (GRC) tool expansion as follows:

> This investment will associate compliance and risk elements with assets in our IT Service Management tool. The system will enable DTE Electric to know if an IT Asset has an associated compliance rule without needing to check manually, which can be prone to human error. The investment will also manage regulation, business, and technology changes more effectively and allow the Company to proactively respond to risks by breaking down restrictive functional, business, and organizational silos enabling stakeholders to make risk-informed decisions.[1077]

Ms. Rogers explained Staff's view that DTE had failed to justify the expenditure:

> Without this investment, this task will still be accomplished. Through an audit, Staff asked the Company how many hours per week this task consumes and the hourly wage of the employee who performs this task. The Company stated that 10 hours per week are dedicated to this task and the hourly wage of the employee is $45/hour. This equates to $23,400 per year. The $0.553M cost of this investment does not outweigh the benefit of saving $23,400 per year.[1078]

In rebuttal, Mr. Sharma disputed testified that other considerations justified this investment:

> There are benefits beyond the manual time savings and cost benefit was not the only driver to selecting this as a prudent investment. The additional benefits to the Company are stated in my testimony on PS-122 lines 8-13 and will ensure that IT assets have the necessary compliance and risk elements associated for compliance with regulations and standards.[1079]

[1077] 7 Tr 2044.
[1078] 8 Tr 5360.
[1079] 7 Tr 2145.

In its brief, DTE relies on Mr. Sharma's testimony as justification for the project. It also cites rebuttal testimony from Ms. Crozier and Ms. Uzenski regarding this and other shared assets,[1080] contending that if the Commission disallows the expenditures for a shared asset, it must also disallow the shared revenue, from DTE Gas, that DTE has included in this case. Staff seems to generally agree, without fully endorsing DTE's correlative claim that approval of shared assets in DTE Electric's rate case constitutes approval for DTE Gas to pay the shared revenue associated with the shared assets.[1081]

c. Projects with no business case (B5.7.5, lines 28)

Ms. Rogers identified several projects for which DTE did not present a business case, including one project on this schedule with projected test year expenditures totaling $312,000 as shown on Exhibit S-12.7, page 6. Mr. Sharma explained that DTE mistakenly thought the project sizes were below the threshold for requiring a business case document. DTE agrees with Staff's adjustment regarding this project.[1082] Therefore, this PFD considers this issue resolved.

8. Information Protection Security (Schedule B5.7.6)

The only disputed issues regarding this schedule involve Staff's adjustments for Level 1 and level 2 estimates. For the reasons discussed above, this PFD recommends that Staff's exclusion of test year projections on lines 7 and 8 and Staff's reduction of 20% to the 10-month bridge and test year projections on lines 1-3 and 6 be adopted.

[1080] Crozier, 7 Tr 2394; Uzenski, 7 Tr 2786-2787; Schedule HH1 of Exhibit A-43.
[1081] Staff brief, 133.
[1082] DTE brief, 127.

9. Infrastructure operations (Schedule B5.7.7)

a. Level 2 estimates (B5.7.7, lines 1-2, 4-6, 8-10, 12-14, 16-17, 19)

For the reasons discussed above, this PFD recommends that the Commission adopt Staff's adjustments to the Level 2 estimates on Schedule B5.7.7.

b. Projected vs historical (B5.7.7, line 3)

Dr. Wang recommended a reduction of $23,944 to the 2021 expense estimate for the Field Communications Network FCN Growth and Upgrade. As shown Exhibit S-7.46, she calculated that DTE spent only 94% of its 2020 projection in Case No. U-20561 and adjusted the 2021 projection accordingly. As discussed above in the plant and field category, this PFD does not find this a reasonable adjustment given the availability of actual spending for 2021.

c. Network Advanced Metering Infrastructure Support (B5.7.7, line 11)

Although Staff initially recommended that the Commission reject the company's expense, as explained in Staff's brief, page 105-106, this issue has been resolved.

d. Virtual desktop infrastructure (B5.7.7, line 15)

Mr. Sharma explained this investment as in an enhancement of the capability of the company's virtual desktop infrastructure in light of an increase in the number of employees working from home due the pandemic:

> [DTE] will invest $0.4M necessary to enhance the infrastructure that allows our remote workforce to connect to the applications and data required for daily work. The COVID-19 pandemic resulted in the Company instituting a policy of remote work and requires most of our employees and contractors to work from home or other secured and safe locations. This increased demand on the hardware and configuration that ensure our employees can access their requisite data, applications, and communications tools. The virtual desktop infrastructure must be

> increased to match the increased employee demand of a remote workforce.[1083]

Staff objected to the expenditure as no longer necessary to address COVID. Ms. Rogers testified:

> Virtual desktop infrastructure is in less demand now than in 2020 and 2021, when the majority of employees were working from home. Through an audit, the Company provided the results of a survey regarding the number of employees from DTE Electric Company and DTE Energy Corporate Services, LLC working remotely. According to the survey of which 88% of employees responded, 42% of the employees are working from home exclusively and 19% are working a mix of at home and at a DTE location. Staff argues that the Company is experiencing a decreased demand in virtual desktop infrastructure from the demand in 2020 and 2021.[1084]

In rebuttal, Mr. Sharma disagreed:

> [W]hile the COVID-19 pandemic initiated the demand to enhance the Virtual Desktop infrastructure, the demand for employees to work from home or in hybrid work model will remain a standard for the Company. The Company will continue to operate with employees exclusively working from home and employees working in hybrid model allowing for flexible work locations based off job duty demands.[1085]

DTE relies on Mr. Sharma's testimony.[1086] Staff urges the Commission to adopt its recommended adjustment, citing Exhibit S-12.7 to show that only 42% of employees are working from home exclusively.[1087]

This PFD acknowledges that fewer employees are working from home, but does not find the company's project therefore obsolete and given the relatively small cost, recommends that it be accepted.

[1083] 7 Tr 2097.
[1084] 8 Tr 5758.
[1085] 7 Tr 2144.
[1086] DTE brief, 138-139.
[1087] Staff brief, 113-114.

e. Command center stand up (B5.7.7, line 18)

Mr. Sharma explained the company's projected expenditures as part of a 3-year project:

> This multi-year project further invests in the implementation of the IT Operations Command Center in 2021 and conclude in 2023 by building out a physical space designed to support both ongoing operations, incident management response teams, and the requisite equipment, staffed by experts throughout the organization. In 2021 through 2022 we will complete the construction of the physical facilities needed to establish the Command Center, enhance the dashboards necessary for monitoring data and increase staffing by one headcount. These investments will provide focused insight into the overall health of Information Technology assets, infrastructure, security, services, and user experiences.[1088]

He testified that a do-nothing option at this point would "effectively halt the work in progress and render the past investment of $0.3 million incomplete."[1089] Staff recommended that the projected expenditures be rejected due to ambiguity in the company's proposal. Ms. Rogers explained:

> Company witness Sharma's testimony states this project is for the construction of a physical space for a team to monitor IT asset health, infrastructure, security, services, and user experiences. However, the business cases state that the objectives are to: 1) Establish what operations will reside in the Command Center, 2) Work with leaders and staff to map a transition organizationally and physically, and 3) Work through principles of Organizational Change Management to retain, retrain, and develop. Neither testimony nor the business cases present any evidence of how this project will benefit safety or reliability of electric service to customers. If the request is building a physical space for this team, Staff is unsure why the current space or the extra space in DTE's facilities vacated by more employees working remotely is inadequate. If the request is to reorganize to create the incident management response team (retain, retrain, and develop) for the Command Center, Staff questions why an extra investment is necessary for employees already employed by DTE.[1090]

[1088] 7 Tr 2099-2100.
[1089] 7 Tr 2100.
[1090] 8 Tr 2358-2359.

In rebuttal, Mr. Sharma testified that the project is for a physical structure, and reiterated why he believes it is important.[1091]

DTE relies on Mr. Sharma's rebuttal testimony. Staff argues that the Commission should adopt its recommended exclusion of the costs for this project. Addressing Mr. Sharma's testimony, Staff argues that "it is still unsure if this investment is for the building of a completely new standalone facility or for the reconstruction of a current onsite space along with monitoring and other necessary equipment." Staff argues that a new space should not be needed given the number of employees working remotely. In DTE's reply brief, it asserts that the command center will not be "standalone," and further argues that the project "relates directly to customers because the critical applications support key business operational processes that all the Company to fulfill its business processes, operations, and customer service requirements."[1092]

A review of the business case documents in Schedules N1.208 and N1.209 for this project line confirms the ambiguity Staff has identified. This PFD finds that DTE has not supported the reasonableness and prudence of its expenditures and they should be excluded from rate base.

G. Corporate Services (Schedule B5, line 11 and Schedule B5.8 in Exhibit A-12)

1. Electric vehicle fleet and maintenance (B5.8, line 1)

Line 1 of Schedule B5.8 reports 2020 spending of $20.7 million for the company's fleet of vehicles, with projected 2021 spending of $28.98 million, 10-month bridge period spending of $11.1 million and projected test year spending of $40.06

[1091] 8 Tr 2144.
[1092] DTE reply, 108-109.

million. Ms. Uzenksi testified in support of the company's projected spending, testifying that the company's projections are higher than 2020 levels due to "light and medium duty trucks not being available for purchase in 2020 due to the shortage of microchips and raw materials such as rubber and foam for seats required by automotive manufacturers."[1093]

Mr. Evans reviewed DTE's past and projected fleet spending for Staff. He recommended a reduction of $ 20,425,000 to the company's test year projection, explaining:

> There is too much risk the Company will not spend its entire test year capital expenditure projection for Vehicle Fleet, because the microchip shortage and other supply chain problems may still be ongoing later this year and into 2023.[1094]

Mr. Evans cited Ms. Uzenski's acknowledgement that the company's 2021 projection as reported in its rate case filing was about $7 million above actual, and he cited Exhibit S-16.1 to show that actual 2021 expenditures were $7.3 million below the 2021 reported value on Schedule B5.8. He concluded that if the additional $7.3 million were spent in 2022, the 10-month bridge period spending could be $18.374 million. He then expressed skepticism regarding the company's projected test year spending, citing automotive industry sources projecting the chip shortage to continue.[1095] He recommended holding projected test year spending to the same amount DTE spent in 2021, noting that if DTE ends up spending more, it can ask for recovery of the additional expenditures in a future rate case.

[1093] 7 Tr 2727.
[1094] 8 Tr 5427.
[1095] 8 Tr 5429.

In its brief, Staff notes that DTE not file rebuttal testimony addressing Mr. Evans's recommendations. This PFD notes that DTE also did not brief the issue. This PFD finds that Staff's recommended test year adjustment should be adopted for the reasons explained by Mr. Evans.

2. Facilities—construction and upgrade (B5.8, line 2)

Relative to 2020 reported expenditures of $32.95 million as shown on line 2 of Schedule B5.8, DTE projected bridge period spending of $70.25 million and test year spending of $38.96 million. Ms. Uzenksi described the expenses included in this category:

> Facilities Construction & Upgrade[] includes capital maintenance and replacement items such as roofs, facades, heating and cooling equipment, elevators, cranes, and paving. Capital maintenance standards are applied to optimize life cycle costs and ensure safety. Larger projects in 2021 include $7 million for replacement and repairs to HVAC systems and $3.4 million to complete the replacement of water piping in the General Offices building. Projects during 2022 and 2023 include $7.5 million for paving at various locations, $4.5 million to replace fire detection and annunciation systems at the downtown campus, $4 million for electrical work at various locations, $3 million to replace the substation at the Walker Cisler Building (WCB), $7.6 million to repair and replace elevators at various locations, and $20.4 million for HVAC replacements including boilers, chillers, piping, air handlers, diffusers, variable air volume boxes, and other equipment.[1096]

Mr. Coppola testified that 2021 expenditures were $3.17 million less than the rate case projection, recommending that this amount be removed accordingly. Regarding the remaining 10-month bridge period, he considered that DTE's forecast of $32.94 million contained "several ballpark cost estimates" for work that may be done in 2022. He looked at a 3-year average of historical expenditures in recommending a $2.89 million reduction to the bridge period expenditure and a $2.92 million reduction to the

[1096] 7 Tr 2728.

company's test year projection.[1097] DTE did not present rebuttal testimony regarding this recommendation, and DTE does not address it in its briefs. This PFD finds that the recommended adjustment should be made for the reasons explained by Mr. Coppola.[1098]

3. Facilities renovation (B5.8, line 3)

DTE reported 2020 costs of $14.56 million for facilities renovation, with projected expenditures of $30.33 million for the bridge period and $1.67 million for the test year. Ms. Uzenksi described this line item as including the costs of a project DTE began in 2012 to update the company's service centers and headquarters, with approvals granted in prior cases:

> When we started the project, approximately 80% of our facilities was over 20 years old requiring costly maintenance. The project includes replacing old infrastructure such as ductwork and air vents; replacing out of date facilities used by employees such as locker rooms, showers, and cafeterias; and replacing furniture and fixtures that ar at the end of their useful life. Because most of our facilities have not been through a full renovation, they did not meet current building codes. Bringing the spaces up to code includes fire detection and suppression, and ADA compliance. Upgrades also include sustainable design including recycled and recyclable materials, energy efficient lighting, low flow faucets, urinals, and toilets. In addition, the project use a more efficient design resulting in a reduction in average space used per employee from 340 square feet to 283 square feet, which allows the Company more space to accommodate additional employees if needed. The project also includes $11 million to refresh five floors in the WCB to reflect a post-COVID flexible workspace design.[1099]

Mr. Coppola recommended that the Commission remove $8.33 million from the 10-month bridge period and $1.67 million from the projected test year attributable to renovations primarily to the company's headquarters building. He cited DTE's

[1097] 8 Tr 4812-4813.
[1098] Also see Attorney General brief, 75-76.
[1099] 7 Tr 2729.

acknowledgement that a significant number of employees are working remotely with no near-term plan to return to the office, further explaining:

> The Company also reported that it plans to begin a workspace arrangement with fewer dedicated workstations and more sharing of workstations. Given the uncertainty of how office space will be used in the next two years, it makes little sense to spend $10 million on renovations to office space in 2022.[1100]

DTE did not address this adjustment in rebuttal or in its brief. This PFD therefore recommends that the Attorney General's recommendation be adopted for the reasons explained by Mr. Coppola.[1101]

4. Service Center optimization (B5.8, line 4)

DTE reports 2020 expenditures of $11.69 million for its service center optimization project, and projected bridge period and test year expenditures of $46 million and $40.95 million respectively. Ms. Uzenski described this as another project to replace facilities that have exceeded their useful life by consolidating some sites and updating other existing sites, which would reduce the company's operating expenses and be completed by 2025.[1102] She described consolidations and upgrades that would take place.[1103]

Mr. Coppola focused on her testimony regarding the original and subsequently canceled plans to move the Wixom pole yard:

> Company witness Theresa Uzenski stated that the Company had decided to cancel the relocation of the Wixom pole yard which had been estimated at a cost of $5.0 million, with $4.5 million included in the projected test year. In response to discovery, the Company confirmed that although the

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[1100] 8 Tr 4813-4814.
[1101] Also see Attorney General brief, 76-77.
[1102] 7 Tr 2729.
[1103] 7 Tr 2730-2730.

project had been cancelled the capital expenditures still remained in the filed exhibits and in rate base.[1104]

He recommended that the $4.5 million be removed from the text year projection. DTE adopted this adjustment in its initial brief, Attachment A. This PFD considers this issue resolved.

5. Headquarters Energy Center (B5.8, line 5)

Ms. Uzenski described the Headquarters (HQ) Energy Center as a new facility that was approved in Case Nos. U-20162 and U-20561, and went into service in November 2021 to provide steam service fueled by natural gas and chilled water for the company's downtown buildings. In her direct testimony in this case, she identified cost and reliability problems with the company's reliance on steam purchases from Detroit Thermal, citing annual price increases and unplanned outages attributable to Detroit Thermal's switch to a temporary plant during a planned outage.[1105] She further testified that the cooling towers at the company's Service Building and Walker Cisler building were degraded. She testified that the HQ Energy Center leads to simplified maintenance, and reduced labor associated with cooling, and better control over steam costs and operation, as well as "preventing the steam leakage that created corrosion to our underground electrical system, heat interruptions to our buildings and damage to landscaping."[1106] Acknowledging an increase of $8.4 million in the projected cost of the project in Case No. U-20561, she obliquely referenced the company's original explanation for the project in stating: "The base NPV analysis no longer shows a

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[1104] 7 Tr 4814.
[1105] 7 Tr 2733.
[1106] 7 Tr 2734.

savings."[1107] She further testified that Detroit Thermal rates have increased annually at an average rate of 5% from 2012-2020, and DTE believed that prices would increase further as Detroit Thermal made critical repairs to its system, potentially causing a loss of customers and the equivalent of an adverse selection spiral:

> The risk of Detroit Thermal losing customers and shifting more costs to DTE is not reflected in DTE's base NPV analysis; but if that did happen, the NPV savings would be positive. In addition, the service provided by Detroit Thermal continued to be unreliable. For example, their steam main failed in May 2021 and DTE's HQ campus did not have steam until DTE's new plant came online in November 2021. Environmental impacts should also be considered. Detroit Thermal now relies exclusively on natural gas because they closed the incinerator that burned trash to produce some of the steam, and their delivery system is old and inefficient. The HQ Energy Center is expected to be more efficient, resulting in a lower carbon footprint. Given these considerations, the Commission should continue to support recovery of the HQ Energy Center.[1108]

Mr. DeCooman explained Staff's recommended disallowance of $7.7 million from bridge period capital expense projection. After agreeing that the Commission approved the project in Case Nos. U-20162 and U-20561, Mr. DeCooman explained that at the time of the initial approval in Case No. U-20162, the NPVRR of the $32.5 million project showed a $4.1 million cost advantage for the project versus the status quo.[1109] He testified that the analysis in that case included $4.47 million in contingency in the cost of the new facility. In Case No. U-20561, he explained, the projected cost of the project had increased to $39.4 million, including $3.2 million in contingency, but the NPVRR analysis still showed a $3 million advantage over the status quo. Given the additional cost increase, Mr. DeCooman explained that the project would only appear better than the status quo if Detroit Thermal rates are projected to increase at a compound annual

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[1107] 7 Tr 2735.
[1108] 7 Tr 2735.
[1109] 8 Tr 5294.

growth rate of 7%, which he characterized “the most aggressive increase . . . higher than any other period since 2012.”[1110] He presented a chart at 8 Tr 5296 to show the NPVRR comparison at various level of rate increase assumptions. He cited Exhibit S-10.1 to show that the HQ project cost at which the NPVRR would equal the NPVRR of the status quo is $40.1 million, and explained that Staff’s recommended disallowance of $7.7 million adjusts the project cost to that level, further explaining:

> Staff is recommending this adjustment due to the basis for the Commission’s initial approval of this project in Case No. U-20162. The Commission specifically cited the favorable economics identified in the NPVRR analysis as supporting this project as reasonable and prudent. The costs and the economics demonstrated in the NPVRR analysis have changed significantly since this project gained initial approval. Notably, while the costs had increased $6.9 million, or over 20%, from the request in Case No. U-20162 to the request in Case No. U-20561, the NPVRR analysis still showed the potential for this project to be economic, given potential future rate increases from Detroit Thermal that had historical precedent.
>
> Additionally, the Company noted that from Case No. U-20162 to Case No. U-20561 the plan designs for the project progressed from 30% to 90% complete, showing significant project development to help explain these cost increases. The Company attempted to justify an additional $8.4 million, or over 20% increase, from its prior estimate in this case. However, considering the advanced development of this project at the point of the project’s approval in the previous rate case, Staff finds that such cost increases could, and should, have been identified while this project was in the development process, which would have significantly changed the economic evaluation and provided the Commission with a clearer picture to inform its decision. It is unreasonable for ratepayers to have to bear the burden of cost increases of nearly 50% above the original estimate used to justify this project in the first place.[1111]

[1110] 8 Tr 5296.
[1111] 8 Tr 5297-5298.

Citing the company's breakdown of the cost increases in Exhibit S-10.0, he testified that "if the Commission finds some of the cost increases . . . to be reasonable, Staff recommends a partial disallowance of $3.85 million" as an alternative.[1112]

Citing the same discovery response in Exhibit AG-1.25, Mr. Coppola testified:

> Two of largest reasons for the $8.4 million cost overrun were $3.9 million for a revised cost for new gas service and $1.3 million of DTE project management. Both of these cost overruns were within the control of the Company and involved Company employees or affiliated entities. Customers should not pay for those higher costs. The Company has not justified why its own project management costs exceeded previous cost estimates and why the cost of installing gas service to the facility would increase by $3.9 million. The project was approved by the Commission based on the initial cost estimate and the Company needs to be held accountable for cost overruns within its control.[1113]

Mr. Coppola recommended a reduction of $5.2 million to reflect the cost overruns for these two items.

In rebuttal, Ms. Uzenksi presented an alternate calculation of the compound annual growth rate for Detroit Thermal rates to show that Staff's disallowance should be reduced:

> Detroit Thermal's base rate increased in Case No. U-20824 on August 11, 2021; the billed SSCR (Steam Supply Cost Recovery) factor has also increased since 2020. Their average total rates from 2020-2022 are $26.14/Mlb, $27.45/Mlb, $31.31/Mlb respectively. The year 2022 is an average of January – May. This represents a 6.20% CAGR compared to the 4.5% assumed in the 21 Company's original analysis. This is shown on line 2 of my Rebuttal Exhibit A-43 22 Schedule HH4.[1114]

In Schedule HH4, she compared the revised NPVRR of $68.07 million she calculated for the status quo to the NPVRR of $70.07 million the company earlier provided to Staff

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[1112] 8 Tr 5298.
[1113] 8 Tr 4815-4816.
[1114] 7 Tr 2782.

for the HQ Energy Center,[1115] and calculated a new "breakeven" HQ Energy Center cost of $46.36 million. She testified that using the updated difference between the breakeven point and actual cost of $1.4 million, she testified the company believes this amount should be split between the company and ratepayers.[1116]

In response to Mr. Coppola, she cited the company's discovery response indicating that the cause of the $3.9 million increase in the cost of installing gas service to the facility was due to the City of Detroit's requirement to "open cut" in lieu of directional boring as the company had originally planned. Citing the same discovery response, she testified that she had indicated that the increase in project management cost "was due primarily to an increase in Allowance for Funds Used During Construction (AFUDC)."[1117]

In its brief, DTE reviews the record and relies on Ms. Uzenski's rebuttal testimony.[1118] In its brief, Staff argues that the company's revised breakeven point analysis is flawed and unreliable:

> The main issue with the updated calculation is the reliance on 5 months of 2022 data to calculate the CAGR of Detroit Thermal's rates. Using a partial year to make a calculation that otherwise uses average annual data skews the calculation. When recalculating the CAGR using the three most recent full years of data (2019 through 2021), the resulting CAGR is 4.31%. This amount is in line with the 4.5% CAGR originally used by the Company to calculate the breakeven point used in Staff's proposed disallowance. (Uzenski, 7 TR 2782.) Therefore, the Company's updated breakeven point calculation should be disregarded, and Staff's initial recommended disallowance for this project of $7,700,000 should be adopted.[1119]

[1115] DeCooman, 8 Tr 5295.
[1116] 7 Tr 27-83.
[1117] 7 Tr 2781.
[1118] DTE brief, 142-144.
[1119] Staff brief, 137-138.

The Attorney General argues that Mr. Coppola's adjustment should be adopted, contending that this project was approved by the Commission based on the initial cost estimate and the Company needs to be held accountable for cost overruns within its control.[1120] Regarding the company's revised savings calculation in rebuttal, the Attorney General cites Exhibit AG-1.63, and argues that Ms. Uzenski failed to mention that the cost of natural gas to fuel the energy center has also increased, with higher natural gas prices than previously included in the company's benefit cost analysis.[1121]

In its reply brief, DTE seems to acknowledge Staff's point that the 5-month analysis is not reliable, but then argues "Staff reaching back another year in history (to 2019) skews the CAGR downward and neglects the whole point of doing an updated analysis."[1122] It argues that the Attorney General "vaguely incorporates witness Coppola's proposal," and objects to the Attorney General offering a criticism of the company's rebuttal CAGR analysis because Mr. Coppola's testimony addressed the $5.3 million in cost overruns that DTE attributes to the City of Detroit requirement and "an increase in AFUDC."[1123]

In her reply brief, the Attorney General emphasizes the magnitude of DTE's cost overruns from the original project approval, $8.3 million, and Ms. Uzenski's acknowledgement in her direct testimony that the project was no longer cost justified. The Attorney General argues that higher gas costs must be taken into consideration along with Detroit Thermal rate increases if DTE's analysis is to be updated. She also argues that DTE did not disclose in its filing the reason for $3.9 million of its cost

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[1120] Attorney General brief, 77-78.
[1121] Attorney General brief, 78.
[1122] DTE reply, 114.
[1123] DTE reply 114-115.

overrun since Case No. U-20561, but waited until Ms. Uzenski's rebuttal to explain the open-cut construction requirement. The Attorney General argues DTE did not establish that it could not have anticipated this requirement in advance of committing to the project: "If the Company had done proper project analysis and due diligence, the initial cost estimate for the project would have included the additional cost for open trench along with most of the other cost overruns. . . . [T]he higher cost would have made the project uneconomical and unlikely to be approved by the Commission."[1124] Regarding DTE's reliance on AFUDC as justification for the cost overruns, the Attorney General argues that Ms. Uzenksi did not provide supporting details, did not indicate how much of the $1.4 million is actually due to AFUDC, and should have provided this information in response to discovery in Exhibit AG-125: "Instead, it labeled the $1.4 million as DTE project management costs. AFUDC and project management costs are two distinct items and one is not typically confused for the other."[1125]

This PFD finds Staff's adjustment should be adopted. DTE chose to base its decision regarding this project on saving energy costs; it did not establish that any such savings materialized. The company's contrary analysis was presented in rebuttal, wrongly incorporated only five months of a year, and failed to reflect any natural gas increases at the same time. DTE's attempt to shrug off the Attorney General's reference to gas prices as "not comparable to Detroit Thermal's full cost of steam service" clearly ignores that gas prices must be an element of its comparison between the Detroit Thermal service and the HQ project DTE undertook. Additionally, DTE did not show that

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[1124] Attorney General reply, 24-25.
[1125] Attorney General reply, 25.

it undertook reasonable efforts to confirm its construction costs, including coordinating with the City of Detroit before it presented its savings analysis to the Commission. While DTE also cites “increased AFUDC,” it did not establish that increase as reflective of anything other than the company’s cost overruns, and as the Attorney General argues, did not establish why it labeled AFUDC as “increased project management costs.” As stated elsewhere in this PFD, any effort by DTE to include AFUDC in rate base should be done transparently.

6. Enterprise Automation (B5.8, line 8)

Ms. Uzenksi testified in support of the company’s projected bridge and test year spending for its enterprise automation project, which she described in part as follows:

> Enterprise Automation engages in automation, digitization, and process improvement initiatives across the Enterprise. Robotic Process Automation (RPA) software is used to program automations that perform repeatable, rules-based, and digitized tasks. The automations, or “bots,” replicate the actions of a human user to perform and complete manual processes. Automating these manual processes allows for resources to focus on higher value activities, reduces the opportunity for human error, and augments controls and capability.[1126]

Staff recommended a $596,000 reduction to the company’s 2021 projected spending for enterprise automation, to reflect the company’s actual 2021 spending. In rebuttal, DTE agreed, resolving that element of the company’s projection.

Staff initially also objected to DTE’s projected spending both for 2022 and for the test year, as Ms. Rogers explained at 8 Tr 5362-5363, because the company did not provide the specific processes that would be automated and the associated costs. In rebuttal, Ms. Uzenski provided Schedule HH5 of Exhibit A-43, containing information

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[1126] 7 Tr 2737.

that was not available at the time the company filed its case.[1127] Staff finds this information satisfactory, as explained in its brief, stating that it "appreciates the updated information and withdraws its recommendation to disallow $9.16M in the 10 months ending 10/31/22."[1128]

Staff clarifies that it now objects only to the projected test year spending of $11 million.[1129] Regarding that projection, Ms. Uzenski testified in rebuttal:

> The Company is anticipating spending $11.0 million in 2022. The Company plans on using the same methodology to identify, evaluate, prioritize, and execute Enterprise Automation projects to spend $11.0 million in 2023. Also, Witness Rogers mentions that Enterprise Automation has grown 63% since its inception; thus, assuming the spend will remain flat from 2022 to 2023 is conservative and reasonable.[1130]

In its brief and reply brief, Staff emphasizes its view that it is not appropriate to fund the 2023 project because the enterprise automation opportunities have not yet been identified. DTE relies on Ms. Uzenksi's rebuttal testimony.[1131]

This PFD finds that Staff and the company have resolved to their mutual satisfaction the spending projections for this item for the 22-month bridge period. In acknowledging Staff's effort to resolve this matter, this PFD also notes that Staff is accepting the company's presentation of new information in rebuttal, although elsewhere Staff has considered this too late in the process, and prior Commission decisions have made clear that placeholder projections—with details to be supplied late in the process—are not proper for rate cases. To avoid having to distinguish the new information DTE submitted in rebuttal in this case and Staff reviewed and accepted from

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[1127] 7 Tr 2737
[1128] Staff brief, 141.
[1129] Staff brief, pages 140-142.
[1130] 7 Tr 2784-2785.
[1131] DTE brief, 144-145; DTE reply, 115-116.

other instances in this case and other cases in which Staff as well as other parties have contended that new information submitted in rebuttal cannot be reviewed, this PFD expressly notes that respecting the dispute resolution efforts of the parties does not modify the otherwise applicable rate case standards.

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

H. Residential Battery Pilot (Schedule B5, line 13, Schedule B5.10)

The residential battery pilot is addressed below in section XII. Consistent with the findings in that section, this PFD concludes the project costs of this pilot should be excluded from rate base.

I. Accumulated Provision for Depreciation

The differences between DTE's and Staff's balance for the accumulated provision for depreciation are driven by differences in net plant projections, as discussed above. As shown in Attachment B to this PFD, the recommendations above result in an accumulated provision for depreciation of $6.98 billion. This balance should be made consistent with the Commission's final decision in this case.

J. Working Capital

DTE presented its working capital calculation in Exhibit A-12, Schedule B4, showing a total company working capital of approximately $1.26 billion. Ms. Uzenski testified that the company's working capital amounts were determined in accordance with the now-standard balance sheet methodology established by the Commission in

Case No. U-7350. Ms. Schreur explained Staff's reduction of $8.1 million to remove an item from DTE's accounts receivable balance that is considered non-utility and non-recoverable.[1132] In its brief, DTE adopted Staff's adjustment.[1133] No other party disputed the projected working capital balance, and this PFD concludes it should be adopted.

K. Rate Base Summary

As shown in Attachment B, this PFD estimates that the recommendations discussed above result in a projected rate base of $20.47 billion.

VI.

COST OF CAPITAL

The rate of return component of the revenue requirements determination is designed to meet the constitutional and statutory standards entitling the utility to a fair rate of return on its investment. The Commission in its past decisions and the witnesses testifying in this case recognize as controlling precedent the U.S. Supreme Court cases *Bluefield Water Works Co v Public Service Comm of West Virginia*, 262 US 679; 42 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944).

To determine the rate of return to use in setting rates, it is customary to start with the development of an appropriate capital structure, and then to evaluate the appropriate costs to assign each element of the capital structure. The appropriate capital structure is discussed in subsection A below, the cost of debt is discussed in subsection B, and the cost of equity capital is discussed in subsection C. The overall

[1132] 8 Tr 5060.
[1133] DTE brief, 17-18.

rate of the rate of return component of the revenue requirements determination is designed to meet the constitutional and statutory standards entitling the utility to a fair rate of return on its investment. The Commission in its past decisions and the witnesses testifying in this case recognize as controlling precedent the U.S. Supreme Court cases *Bluefield Water Works Co v Public Service Comm of West Virginia*, 262 US 679; 42 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944).

To determine the rate of return to use in setting rates, it is customary to start with the development of an appropriate capital structure, and then to evaluate the appropriate costs to assign each element of the capital structure. The rate of return used to set rates is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that component by the cost rate for the component. The weighted cost rates for each component are then added to determine the overall rate of return.

A. <u>Capital Structure</u>

The capital structure used for ratemaking includes as its components long-term debt, preferred stock, and common equity capital, along with short-term debt and other items such as deferred taxes that reflect sources of financing available to the company. Only long-term debt, preferred stock, and common equity capital are considered part of the utility's "permanent" capital, and it is common for capital structures to be shown in exhibits on both a "permanent" basis and on a ratemaking basis. DTE does not have preferred stock, so discussions of its permanent capital structure refer only to long-term debt and equity ratios.

As the Commission has indicated:

> The appropriate capital structure of a utility is based on considerations of cost and risk, and in accordance with these considerations, the Commission has from time to time adjusted a company's capital structure to one that was more reasonable. While a company with more debt is a financially riskier enterprise, a company with more equity has a greater amount of capital invested in the most expensive type of capital. Not only is equity capital more expensive than debt capital, but the return on equity adds a tax burden to total revenue requirements, whereas debt does not. Thus, the Commission seeks an appropriate balance between the risks and costs of investor and debt funding.[1134]

1. Common Equity Balance

There is no dispute among the parties that the Commission should use a permanent capital structure with 50% equity and 50% long-term debt. Mr. Lepczyk is recommending a projected permanent capital structure of 50% long-term debt and 50% common equity, which is the same permanent capital structure authorized by the Commission in DTE's last general rate case, Case No. U-20561.[1135] Mr. Ufolla and Mr. Coppola also recommend a common equity ratio of 50%.[1136] Mr. Garrett recommended the Commission set a capital structure consisting of 53% debt and 47% equity,

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[1134] Case No. U-17999, Order, February 28, 2017, p. 63.
[1135] 7 Tr 1283-1284, 1287-1288; Exhibit A-14, Schedule D-1. Mr. Lepczyk states that a 50/50 capital structure is not the optimal capital structure for DTE Electric, but that DTE using the previously authorized structure to reduce the number of contested issues in this case. He asserts that the more appropriate capital structure for DTE Electric is closer to that of its peers, which have a capital structure made up of 48% long-term debt and 52% common equity. However, he states that DTE Electric's targeted 50% equity ratio is a reasonable level given that the average ratio of the peer group is higher at 52%.
[1136] 8 Tr 5084; Exhibit S-4, Schedule D-1; Staff brief, 147-148; 8 Tr 4817-4818; Exhibit AG-1.27.

however, in its brief, MNSC accepts maintaining DTE's proposed 50% permanent debt ratio.[1137]

2. Other Debt Balances

DTE, Staff, and the Attorney General agree with the amounts outstanding to be used in the DTE's proposed capital structure for long-term debt, short-term debt, deferred federal income taxes ("FITs"), and the Job Development Investment Tax Credit (JDITC).[1138]

Accordingly, this PFD recommends the Commission adopt DTE's proposed common equity balance of $8,426,264,000 which represents approximately 50.0% of the permanent capital structure and 39.62% of the ratemaking capital structure, as set forth in Appendix D to this PFD.

In addition, DTE's long-term debt balance ($8,410 billion), short-term debt balance ($265.492 million), deferred income tax balance ($4.117 billion), and Job Development Investment Tax Credits balance ($47.376 million) are adopted.

B. Cost Rates

1. Return on Common Equity

A utility's cost of common equity, generally referred to as the return on equity (ROE), is the return that investors expect to provide the utility with capital for use in its various operations. The cost of this capital essentially represents an opportunity cost; in order to induce investors to purchase common stock or bonds, there must be the

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[1137] 8 Tr 3492; MNSC brief, 83. MNSC states that it is not conceding DTE's rebuttal position and that it reserves these issues for a future proceeding. MEC brief, 84.
[1138] 8 Tr 5084; Exhibit S-4, Schedule D-1; 8 Tr 4817-4818; Exhibit AG1.27.

prospect of receiving earnings sufficient to make the investment attractive when compared to other investment opportunities.

The criteria for establishing a fair rate of return for public utilities is rooted in the language of the United States Supreme Court cases *Bluefield Water Works Co. v Public Service Commission of West Virginia*, 262 US 679 (1923) and *Federal Power Comm. v Hope Natural Gas Co*., 320 US 591 (1944). In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[1139]

In *Hope*, the Court stated:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. . . [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[1140]

As enunciated by the Commission in previous rate case final orders, the rate of return "should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the

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[1139] 262 U.S. at 692-693.
[1140] 320 U.S. at 603. Citations omitted.

enterprise."[1141] The Commission also stated that any determination of what is fair and reasonable "is not subject to mathematical computation with scientific exactitude but [rather] depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[1142]

a. DTE

Dr. Villadsen recommends an ROE of 10.25%, which she asserts is a "modest increase over the most recently allowed ROE and very reasonable given developments in capital markets."[1143] She asserts that the determination of DTE'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 risk of industries. She notes that at the same time, some economists have raised inflation fears as the last few months has seen larger increases in the Consumer Price Index ("CPI") than any time since November 1990. She concludes that measures of the premium investors require over and above the risk-free rate to invest in equity (the market risk premium) has increased relative to that of July 2019 (the date of the data in her testimony in Case No. U-20561) and relative to December 2019 (when the record in Case No. U-20561 closed). Noting that DTE's most recent rate case, Case No. U-20561 resulted in a ROE of 9.9 percent on a 50% equity capital structure, Dr. Villadsen states that since 2019, the systematic risk of electric utilities, as measured by beta, has increased as has the market risk premium, while the risk-free rate as measured by government bonds has declined. As such, she argues that the financial markets have changed, which led equity

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[1141] Case No. U-15244, Order, December 23, 2008, p. 12.
[1142] *Id.*, citing *Meridian Twp. v City of East Lansing, Mich*., 342 Mich 734, 749 (1955).
[1143] 7 Tr 1309.

investors to require a higher premium to hold equity instead of debt and for electric utilities such as DTE the relative risk increased. She adds that it is important to recognize that the currently low Treasury yields are not reflective of a low cost of equity; rather data on the forward-looking market risk premium and electric utilities' systematic risk point to a higher return on equity as of today than at the time of DTE's most recent rate case order, which was based on data as of July 2019.[1144]

Dr. Villadsen states that she calculated DTE's cost of equity using a sample of electric utilities and supports her recommendation with an additional sample of highly regulated natural gas and water utilities, but notes that the 10.25% she recommends is fully supported by the electric sample results.[1145]

Dr. Villadsen states that to calculate the ROE that DTE should be allowed an opportunity to earn, she used three methods: (i) the Capital Asset Pricing Model (CAPM) and a variation thereof--the Empirical CAPM (ECAPM), (ii) the Discounted Cash Flow (DCF) model and a multi-stage variation, and (iii) a Risk Premium model. Regarding business risk, she notes that inflation fears, changing requirements for electric utilities along with the need for substantial capital spending leads to substantial business risk for electric utilities. For DTE, which has no decoupling mechanism, any impact on load from the COVID-19 pandemic, energy efficiency, inflation pressures or economic downturns will result in DTE's cash flow being affected and more so than for electric utilities that do have a decoupling mechanism.[1146]

[1144] 7 Tr 1308, 1309.
[1145] 7 Tr 1309, 1310.
[1146] 7 Tr 1310.

When considering risk when estimating the cost of capital, Dr. Villadsen "analyzed and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies", and "analyzed and adjusted for differences between the capital structures of the proxy companies and the regulatory capital structure that will be applied to DTE for ratemaking purposes."[1147] To determine where in the estimated range DTE's ROE reasonably falls, she compared the business risk of DTE to that of the proxy group companies.[1148]

Dr. Villadsen asserts that although current interest rates in capital markets are low, interest rates are expected to increase. Thus, she adds that the allowed fair return on equity for DTE should reflect the future interest rate environment at the time the rates being set in this proceeding will be in effect.[1149] Noting that the current 10-year U.S. Government bond yields are at 1.58%, she states that treasury bonds are forecasted to increase, with Blue Chip Economic Indicators' (BCEI) October 2021 edition forecasting that the 10- 20 year government bond yield will be 1.9%, 2.3% and 2.5% in 2022, 2023 and 2024, respectively.[1150]

Dr. Villadsen states that during the early months of COVID-19, financial markets became extremely volatile as shown in near-term common volatility measures, such as the VIX, which reached an all-time high of 82.69 on March 16, 2020, which was higher than the peak of 80.86 during the Financial Crisis. She adds that since then, VIX has remained elevated for some time but has recently returned to its long-term average level of about 20, which is a bit above the pre-COVID-19 level. Dr. Villadsen states that

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[1147] 7 Tr 1314.
[1148] 7 Tr 1314.
[1149] 7 Tr 1320.
[1150] 7 Tr 1317.

the SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (i.e., sudden substantial downturns), shows that investors are cautious. She concludes that the variability in VIX and SKEW shows that investors expect volatility to continue (for at least a year) but are cautiously optimistic about investing in equity.[1151]

Noting that the financial crisis saw high volatility and a flight to quality – similar to conditions seen in 2020 in response to the COVID-19 pandemic – she argues that it is reasonable to expect that the current market risk premium (MRP) will remain elevated compared to historical levels, especially given the uncertainty related to the extent of economic and financial impacts from COVID-19 and the historically low interest rates.[1152]

Dr. Villadsen asserts that the relative risk of electric utilities such as DTE has increased as demonstrated by the substantial increase in the systematic, non-diversifiable risk (measured by beta) with electric utilities moving closer to exhibiting risks similar to the market in general, adding that the risk premium investors require to hold electric utility stock today is higher than at the time of the last cost of capital proceeding.[1153]

Dr. Villadsen asserts that "rising inflation has introduced new uncertainties to the financial markets and points to an increase in the return required by investors to hold risky assets", and that "with the risk of inflation increasing, there is an increased risk that

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[1151] 7 Tr 1322, 1323, 1324.
[1152] 7 Tr 1327, 1328.
[1153] 7 Tr 1329.

the authorized as well as any currently calculated ROE will be downward biased over the upcoming period.[1154]

Dr. Villadsen asserts that taking the level of financial risk or leverage into account is necessary to reflect the fact that different capital structure ratios have different levels of financial risk. With all else equal, higher levels of debt financing increase the risk faced by equity investors. Therefore, investors require higher ROEs from companies with more debt than from comparable business risk companies with less debt. To reflect the effect of capital structure on the cost of equity, she adjusts the cost of equity estimates she obtains from applying the models to the market data of the proxy companies, using two different approaches: (1) the overall cost of capital approach and (2) the Hamada approach.[1155]

Dr. Villadsen performed her CAPM/ ECAPM analysis using two scenarios: a forecasted risk-free rate and (i) a historical MRP or (ii) a forecasted MRP. These analyses resulted in CAPM ranges of 10.4% - 11.5%, and ECAPM ranges of 10.3% - 11.7%.[1156] Dr. Villadsen concludes that the CAPM / ECAPM indicates a range of 10.25 to 11.50 percent for the electric proxy group before any DTE risks are considered.[1157]

Regarding her DCF analysis, Dr. Villadsen states that she calculated both the single- and multi-stage DCF using growth rates from Value Line and IBES as well as GDP forecasts from Blue Chip Economic Indicators in the case of the multi-stage DCF. Her estimates were 10.4% (simple) and 8.7% (multi-stage). She adds that she "view[s] the multi-stage results as unrepresentative because they fail to include the very high

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[1154] 7 Tr 1334.
[1155] 7 Tr 1342.
[1156] 7 Tr 1344, 1345, 1346.
[1157] 7 Tr 1347.

near-term GDP growth and are out of line with other results."[1158] Consequently, she considers the range determined by the upper half of the estimation results representative, i.e., 9.50% to 10.50% for the electric company peer group.[1159]

For her risk premium analysis, Dr. Villadsen applied the calculated risk premium and a risk-free rate of 2.73% resulting in an estimated cost of equity of 9.8% for all electric utilities.[1160]

Dr. Villadsen addresses the differences in the regulatory environment for the proxy companies and DTE as follows:

> Like many of the sample companies, DTE Electric benefits from certain regulatory policies that reduce regulatory lag, including a forward test year for rate cases, and an annual Power Supply Cost Recovery ("PSCR") clause for expenses such as fuel, capacity, energy, transmission, and purchased power. Subject to Commission review, the Company is permitted to include construction work in progress ("CWIP") for pollution control measures and significant new infrastructure projects in rate base. Cost-tracking mechanisms such as these are also in effect in states affecting several of the sample companies. However, unlike some of the sample companies, DTE Electric does not currently have a revenue decoupling mechanism (since a 2012 Court of Appeals ruling reversed Michigan Public Service Commission approval for such a program that DTE Electric had implemented) or lost revenue adjustment mechanism ("LRAM") in place, as some sample companies do.
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> * * *
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> Like the sample companies, DTE Electric's business is concentrated in regulated electric generation and distribution, and as mentioned above, DTE Electric does have some regulatory mechanisms in place that are comparable to those of the proxy group companies; however, if load is declining, the lack of a decoupling mechanism is a business risk. DTE Electric also has a credit rating of A- from Standard & Poor's, which is comparable to those of the proxy sample companies.

1158 7 Tr 1349.
1159 7 Tr 1348, 1349.
1160 7 Tr 1349, 1350, 1351.

> Regulatory policy plays a role in the business risk of the Company. In the current environment of market uncertainty, the fact that DTE Electric does not have a revenue decoupling mechanism or a fixed variable pricing policy in place puts it at an increased risk of under-recovering its cost of service relative to some companies in the sample group that benefit from such mechanisms. Because the Company recovers much of its fixed cost through per-kWh charges to their customers (i.e. does not benefit from full revenue decoupling or fixed variable pricing), it will be at risk for under-recovery during economic uncertainties. DTE Electric does not have a decoupling mechanism, which more than half of U.S. electric utilities do. This indicates that DTE Electric's business risk is higher than that of its peers.
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> Michigan also allows competitive retail choice for electricity, which may erode sales volume, although state law caps the alternative supply in a utility's service territory at 10 percent of the preceding years' sales.[1161]

She states that the recent economic impacts from the COVID-19 pandemic have increased the business and systematic risk of utilities, including DTE. The Detroit area's economy has been hit particularly hard, with, as of June 2021, the Detroit metropolitan area's unemployment rate at 6.2 percent, while the national average is at 5.9 percent. At the same time the greater Detroit area continues to be economically challenged. However, Michigan currently is expected to see a very high growth in the general economy (GDP).[1162]

Dr. Villadsen also opined that DTE's ownership of the Fermi 2 Nuclear Generating Plant increases the total risk of DTE, although empirical tests of the effects of the ownership of nuclear generating plants on the cost of capital have not shown a statistically significant increase in the cost of capital.[1163] She adds that it may be that nuclear generating plants increase the cost of capital even though empirical tests have

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[1161] 7 Tr 1352-1353.
[1162] 7 Tr 1353, 1354.
[1163] 7 Tr 1354.

not been able to detect it.[1164] As such, she asserts that DTE is of higher-than-average business risk relative to the sample companies.[1165]

Dr. Villadsen concludes that because of 1) the presence of potential drop in demand from customer choice combined with no decoupling mechanism and 2) DTE's ownership of nuclear generation, representing approximately 10% of its generation capacity, it is thus reasonable to place DTE in the upper range of the equity cost estimates.[1166]

b. Staff

Staff recommends adopting an ROE of 9.60%, which is in the upper half of Staff's ROE range of 8.90% and 9.90% provided by Mr. Ufolla.[1167]

To determine the fair return on equity, Staff used a group of twelve publicly traded electric utility companies for a comparable proxy group for Staff's analysis. The proxy group's data is used in both Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) analyses to determine a reasonable cost of equity. Additionally, a Risk Premium model and a review of gas ROE authorizations from other state jurisdictions from 2020-2021 are also utilized by Staff in this case. Finally, Staff's 9.60% recommendation considers the DTE's currently authorized 9.90% and requested 10.25% ROE in this case.[1168] Mr. Ufolla asserts that the DCF and CAPM are the primary

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[1164] 7 Tr 1355.
[1165] 7 Tr 1355.
[1166] 7 Tr 1356.
[1167] 8 Tr 5085.
[1168] 8 Tr 5085, 5086.

models most utility financial analysts use in rate cases to determine a fair and reasonable cost of equity for regulated utility companies.[1169]

Mr. Ufolla notes that DTE Electric currently has an A- rating from S&P, an Aa3 rating from Moody's, and an A+ rating from Fitch. These credit ratings are unchanged since the last rate case. All DTE Electric's ratings include a stable outlook.[1170]

Staff utilized a proxy group consists of nine electric companies that meet five criteria: the company must 1) be listed as electric Utility by Value Line, 2) have a full Value Line report available, 3) be currently paying dividends to shareholders, 4) not be the target of a merger or acquisition, and 5) have a Moody's credit rating of Baa1 or higher. Mr. Ufolla notes that DTE's proxy group excluded proxy candidates with a significant lower credit rating that DTE, which Staff believes to be an important criterion in order to produce a proxy that is most similar to the subject utility, and to assure that the proxy companies have very similar risk profiles. Mr. Ufolla also notes that DTE utilized both gas and water companies as proxies in its analyses, which Staff rejects as gas and water companies are not as similar to DTE as are other electric companies.[1171]

For its DCF analysis, Staff uses the closing stock prices from January, February, and March 2022 along with the most recent quarterly dividend to calculate the annual dividend yields for the proxy group. For growth rates, Staff employed three well-known and widely used sources; Yahoo Finance, Zacks, and Value Line. The average of these sources is used to determine each individual proxy company's growth estimate. All

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[1169] 8 Tr 5087.
[1170] 8 Tr 5086.
[1171] 8 Tr 5087, 5088.

available growth rate data is utilized ranging from 1.30% to 11.00%. Staff arrived at an average adjusted DCF cost of equity estimate of 8.85%.[1172]

Mr. Ufolla criticizes Dr. Villadsen's DCF analysis for including a version of the After-Tax Weighted Average Cost of Capital (ATWACC) approach which Mr. Ufolla asserts has never been approved by this Commission.[1173]

For Staff's historical CAPM analysis, Mr. Ufolla evaluated the historical risk premium, reviewing return data for the entire period 1926-2020. Taking the difference between the average stock return and government bond return indicated a 7.25% risk premium over the period. The risk-free rate used in the CAPM analysis is the yield associated with a long-term 30-year U.S. government Treasury bond with the average projection being 2.823%. Staff uses beta values from Value Line, which Staff asserts is widely accepted in the industry and utilized by every expert witness of which Mr. Ufolla is aware and is a forward-looking beta. Utilizing a risk-free rate of 2.82%, a historical risk premium of 7.25%, and an average beta of 0.86, Staff computes a Historical CAPM cost of equity of 9.08%.[1174]

To account for the forward-looking nature of ratemaking, Staff also conducted a Projected CAPM analysis using Value Line market data. The price appreciation rate (10.07%) was then added to the 1.78% dividend yield to approximate a projected total market return of 11.94% for the test period. Staff then subtracted its risk-free rate of 2.82%, which produced a market risk premium of 9.12%. Substituting this projected

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[1172] 8 Tr 5090; Exhibit S-4, Schedule D-5, pages 3-5.
[1173] 8 Tr 5091; Staff brief, 149-150.
[1174] 8 Tr 5093, 5094.

9.12% risk premium for the 7.25% historical risk premium in the CAPM formula results in a Projected CAPM estimate of 10.69%.[1175]

Mr. Ufolla disagrees with DTE's methodology for the CAPM models for including an ATWACC formula. Mr. Ufolla asserts that when the adjustments DTE uses are removed, DTE's outputs are more in line with Staff's ROE recommendation and thus does not object to considering DTE's unadjusted CAPM outputs (9.10% and 9.64%) in determining a reasonable ROE.[1176] Staff adds that although Dr. Villadsen in rebuttal denies using the ATWACC in her CAPM analyses, multiple parties found calculations within CAPM that were akin to ATWACC and rejected them.[1177]

Mr. Ufolla also notes Staff's disagreement with DTE's use of the ECAPM models, noting that the Commission has not relied on ECAPM analyses in rate cases. He adds that the inputs used in Staff's ratemaking CAPM analysis already account for many of the shortcomings supposedly recognized by ECAPM, and thus render the ECAPM adjustment unnecessary. Mr. Ufolla concludes that Staff's ratemaking CAPM analysis, with its use of long-term risk-free rates and adjusted betas, incorporates the desired effect of the ECAPM adjustment.[1178]

Staff provides three risk premium estimates, two that use the difference between utility equity and utility bond returns, and one that examines the difference between utility equity and Treasury bond returns. Mr. Ufolla states that the average electric utility market return over the period from 1931 through 2021 was 11.05%, the average return of an A-rated composite utility bond was 6.30%, and the average Treasury yield was

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[1175] 8 Tr 5094, 5095; Exhibit S-4, Schedule D-5, pages 6-8.
[1176] 8 Tr 5096, 5097
[1177] Staff brief, 151.
[1178] 8 Tr 5097, 5098.

5.81% over the same period. Subtracting these bond yields from the natural gas market returns gives risk premiums of 4.75% and 5.24% respectively. He adds that taking these risk premiums and adding them to current yields of 3.56% for an A rated utility and 2.82% for a Treasury bond gives an estimate of 8.31% using the A-rated utility bond method and 8.06% using the Treasury bond method. Current Baa-rated utility bond yield of 3.85% were also added to the utility bond premium for a result of 8.60%.

Mr. Ufolla states that although Staff does not fully agree with DTE's Risk Premium model, Staff does not find the results to be unreasonable.[1179] Mr. Ufolla adds that Staff also reviews authorized rate of return decisions for electric utilities rendered by other state commissions across the country for 2020 and 2021, with the average authorized ROE decisions for 2020 being 9.44%, and 9.38% for 2021.[1180]

Mr. Ufolla states that based on the results of the multiple analyses done, along with other factors such as credit rating, DTE requested 10.25% ROE, and currently approved 9.90% ROE, it is Staff's judgement that a reasonable range for DTE Electric's cost of equity is 8.90% - 9.90%. Within that range, Staff recommends a value of 9.60%, which falls in the upper half of Staff's range.[1181]

c. Attorney General

The Attorney General recommends an ROE of 9.50% be adopted in this case.[1182]

Mr. Coppola utilized three approaches to determine this cost: the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and a Utility Risk Premium

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[1179] 8 Tr 5099.
[1180] 8 Tr 5100.
[1181] 8 Tr 5101.
[1182] 8 Tr 4820.

approach. Also, he has considered the current circumstances in the Capital Markets and any potential changes in the risk profile of DTE Electric and the current state of the Michigan economy. Finally, he considered the cost of common equity for a proxy group of peer companies.[1183]

For his proxy group, Mr. Coppola started with the 37 electric utility companies followed by the Value Line Investment Survey, and eliminated six companies due to size considerations, three companies with annual revenues at $1.0 billion or less, three companies whose dividends are not growing, two other companies due to its foreign investments, three other companies for facing higher risks due to wildfire liabilities, nuclear generating plant construction, and the construction of off-shore wind electric generating facilities, and several other companies involved in merger and acquisition (M&A) activity or reorganizations or that are facing earnings growth challenges. The result is a proxy group of thirteen companies, all of which have growing earnings and dividends.[1184] Mr. Coppola notes that DTE's electric peer group includes many companies he eliminated for the reasons stated.[1185]

Mr. Coppola also notes that Dr. Villadsen relies on an additional group of purported peer companies that consist of eight water companies and eight natural gas companies, which additional group he asserts is not necessary given the availability of a sufficiently large number of public electric utility companies that offer a better match to the electric business that DTE is in.[1186] He adds that previously the Commission noted

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[1183] 8 Tr 4820, 4821.
[1184] 8 Tr 4821; ExhibitvAG-1.29.
[1185] 8 Tr 4822, 4823.
[1186] 8 Tr 4823.

its concerns with including water companies in proxy group results in electric rate cases in the Commission's order in Case U-18999.[1187]

In his DCF analysis, Mr. Coppola used the average of the high and low prices for each of the equity securities on each of the 30 trading days ending on April 11, 2022, the average projected dividend level for 2022 and 2023 as calculated by the Value Line Investment Survey, the average long-term earnings growth rate based on Value Line 2022 projections of earnings per share through the 2025 – 2027 period, and Yahoo Finance analysts' projected growth in earnings per share over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.18% for the proxy group.[1188] Mr. Coppola notes that under the DCF analysis, because the forecasted growth rates for the proxy group include some high growth rates which appear to be the result of a temporary rebound in earnings from a low point in recent years and which are not sustainable long-term growth rates, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term.[1189]

Mr. Coppola states that Dr. Villadsen's DCF cost of equity for her electric proxy peer group (10.4%) is higher than his because she is utilizing the After-Tax Weighted Cost of Capital (ATWACC) approach. He states that the key factor causing the escalation in the ATWACC ROE is the use of the stock market value to book value of the common equity for each company in the analysis, which artificially inflates the cost of common equity. He asserts that the upward adjustment from the ATWACC process

[1187] 8 Tr 4825.
[1188] 8 Tr 4827
[1189] 8 Tr 4829, 4830.

for the electric proxy group is 1.0%.[1190] Mr. Coppola urges that the Commission disregard the ATWACC approach as its cost inflating circularity and complexity of the methodology is why the ATWACC approach has not been embraced in the utility industry.[1191]

For his CAPM analysis, Mr. Coppola used (1) a projected 3.20% risk free rate; (2) beta information available from Value Line; and (3) the Historical Market Risk Premium of 7.25% based on the Ibbotson Classic Yearbook. He adds that because sentiment in the market is fairly universal that interest rates, which have been rising, will continue to rise assuming the Federal Reserve Bank's efforts to contain inflation will push up interest rates, he used the most recent projection of interest rates available from Kiplinger as of April 15, 2022 that the ten-year U.S. Treasury bond will reach the 3% level by the end of 2022 anticipating several increases in the federal funds rate over the balance of 2022. To this 3% level, he added 20 basis points which is the average spread between 30 year and 10-year U.S. Treasuries during March 2022 and the first half of April 2022. This results in a 3.2% projected 30-year US Treasury bond rate at year end 2022 to which he adds the beta adjusted peer group risk premium of 6.19% to arrive at the 9.39% ROE rate under the CAPM approach.[1192]

Mr. Coppola adds that Dr. Villadsen's CAPM and ECAPM estimates have been determined utilizing either the Hamada approach with leveraged betas or the ATWACC process, which lead to faulty and inflated results, which he calculates as increases of 1.47% and 1.59% for her two CAPM scenarios. He asserts that the Commission should

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[1190] 8 Tr 4828.
[1191] 8 Tr 4829; Attorney General brief, 85-86.
[1192] 8 Tr 4831, 4832; Exhibit AG-1.30.

reject Dr. Villadsen's methods as highly unconventional, not generally accepted, and being based in part upon her opinion that risk levels have permanently risen since the 2007-2008 financial crisis.[1193]

Under his utility risk premium analysis, Mr. Coppola estimates and adds together three components: (1) the risk-free rate of return on 30- year U. S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of DTE and the 30-year U.S. Treasury Bonds (risk-free rate); and (3) the average return differential of utility common stocks over utility bonds. He states that he used the 4.35% historical spread of electric utility common stock returns relative to utility bonds, a 1.38% (BBB rated) average spread for utility bonds over the U.S. Government bonds (the risk-free rate), and for the risk-free rate, the projected 30-year Treasury rate of 3.20%. This results in a return on common equity of 8.93%.[1194]

Mr. Coppola states that Dr. Villadsen's risk premium approach involved a comparison of authorized ROEs from electric utility rate case decisions from 1990 to 2021 and compared these ROEs to 20-year U.S. Treasury bonds. He asserts that this approach is troubling in that it lacks any comparison of the actual returns of utility stocks to treasury bonds and suggests that treasury bond yields are the primary driver in ROE decisions by regulators.[1195] As such, the Attorney General asserts that this analysis has no validity as a tool to determine the ROE to be established in rate proceedings.[1196]

Mr. Coppola states that the U.S. economy and the Michigan economy have generally recovered from the 2020 recession caused by the Covid-19 pandemic in part

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[1193] 8 Tr 4832, 4833, 4834, 4835.
[1194] 8 Tr 4835, 4836; Exhibit AG-1.31.
[1195] 8 Tr 4837.
[1196] Attorney General brief, 89.

due to the accommodative stance of the U.S. Federal Reserve Bank during 2020 and 2021 by reducing interest rates. More recently, in late 2021 and early 2022, to combat inflation, the Federal Reserve Bank has pledged to increase short term interest rates and is expected to increase long term interest rates. He adds that in his calculations for both the CAPM and Utility Risk Premium methods, he reflected those expectations with a projected 3.2% risk free rate – vs DTE's projected a risk-free rate of 2.73% -- and notes that as of late April 2022, the actual 30-year U.S. Treasury rate is 2.9%. He asserts that nonetheless, DTE's access to the capital markets has remained strong as witnessed by DTE's issuance in April 2021 of $425 million of new 30-year long-term debt at a rate of 3.25% and $575 million of 7- 10 year debt at a 1.9%. In addition, DTE's senior secured debt ratings are A/Aa3 and its commercial paper program is rated P-1 (highest) by Moody's Investor Service. Also, the DTE's parent, DTE Energy, accessed the capital markets in November 2021 issuing approximately $280 million of 60-year long-term debt at a rate of 4.375%.[1197]

Mr. Coppola states that since 1990, return on equity rates, granted by regulatory commissions in the U.S., have been in a steady decline from over 12.7% in 1990 to approximately 9.5% in 2020 and 2021. He notes that the most recent ROE decisions for several companies had ROE rates granted below 10%, and that the ROE rates range from a low of 8.25% to a high of 9.9% with DTE and Consumers Energy having the highest rates in the under 10% ROE group of utilities. The average for the group is 9.32% in 2020 and 9.44% in 2021.[1198] Mr. Coppola adds that the debt capital markets

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[1197] 8 Tr 4838.
[1198] 8 Tr 4839; ExhibitAG-1.32.

have remained strong and continue to provide debt capital at competitive interest rates to utilities with authorized ROEs well below 10%.[1199]

Mr. Coppola states that a reduction in DTE's ROE to 9.5% is unlikely to result in a downgrade of DTE's debt ratings. He notes that Moody's rates DTE's debt as "Aa" and views the Michigan regulatory environment as constructive. A review of the most recent Moody's report on DTE shows that DTE achieved a 22.4% CFO pre-WC to Debt ratio in 2020, which is a key ratio that Moody's uses to evaluate a company's credit worthiness. It is Moody's position that ratio results under 20% for a sustained time could lead to a downgrade of DTE's debt.[1200]

Mr. Coppola calculated a pro-forma CFO pre-WC to Debt ratio based on DTE receiving and earning an ROE rate of 9.50%. He states that the CFO pre-WC to Debt ratio would decline by an insignificant percentage from 22.4% to 22.2%, which is well above the 20% long-term downgrade threshold set be Moody's.[1201]

Mr. Coppola disputes Dr. Villadsen's testimony that DTE has a higher risk profile than the other electric peer group companies because the Detroit service area is "economically challenged" and because it owns the Fermi nuclear power plant, noting that she presents no evidence to support these statements. He notes that the fact that the unemployment rate in Detroit is 6.2% versus the national rate of 5.9% is an immaterial difference. Moreover, he notes that in discovery DTE disclosed that only 10% of its sales to residential customers are in the City of Detroit, again showing this is not a significant factor given that many of the other utilities in DTE's peer group also

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[1199] 8 Tr 4840; Exhibit AG-1.32.
[1200] 8 Tr 4840.
[1201] 8 Tr 4840, 4841.

serve urban areas with depressed economic areas. In addition, he notes that Dr. Villadsen stated that she had not done an analysis of nuclear risk posed to DTE by Fermi 2 versus the electric peer group of companies.[1202]

Mr. Coppola states that any increased volatility in the capital markets is not a concern in establishing a fair ROE. He notes that Dr. Villadsen points to the VIX index which portrays volatility over the next 30 days and that Dr. Villadsen had no projection of the VIX for the projected test year. He states that in setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market. He also points to a Value Line Funds article (Exhibit AG-1.36) which states that volatility is not risk. Mr. Coppola points out that utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to as much volatility as the general stock market, which is reflected in the average beta of 0.85 of the utility peer group used in the CAPM ROE rate calculation and in contrast with the general stock market value of 1.00.[1203]

Mr. Coppola states that the range of returns for the industry peer group is from 8.93% at the low end, using the Utility Risk Premium approach to 9.39% at the high end using the CAPM approach. He calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods, resulting in a weighted return on equity of 9.17%. To this base cost of equity capital, he

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[1202] 8 Tr 4841, 4842.

[1203] 8 Tr 4842, 4843. The Value Line article (Exhibit AG-1.36, page 1) states that "[v]olatility is simply the measure of the up and down movements of the market;" "[r]isk . . . is the probability of permanent loss;" and "[v]olatility is independent of risk."

added an additional premium adjustment of 33 basis points to arrive at his recommended ROE rate of 9.50% for DTE Electric in this rate case.[1204]

Mr. Coppola explains the two reasons for his additional premium adjustment. First, the current state of the economy and financial markets has increased business risk, such that the 33 basis points he added to the calculated cost of equity "provides a cushion to absorb the impact of potentially higher business risk and higher interest rates not currently reflected in utility stock prices and forecasted interest rates."[1205] He adds that the financial markets and stock prices are already anticipating higher interest rates being set by the Federal Reserve, and that the 9.50% ROE rate he proposes goes beyond current market expectations. Thus, he asserts that "there should not be a need for the Commission to add even more of a cushion by setting an ROE rate above 9.50% or even approaching the 9.90% currently authorized for DTE."[1206]

Second, noting that the Commission may be reluctant to grant a ROE at the 9.17% as the true cost of capital at this time, preferring instead a more gradual reduction, he asserts that the proposed 9.50% ROE rate is a reasonable reduction from the last ROE rate of 9.90% granted to DTE approximately two years ago. He adds that Michigan utilities currently enjoy some of the highest ROE rates among utilities in country and are well above the average rate of 9.45%. He concludes that as in prior rate cases, the Commission has expressed a desire to gradually reduce those ROEs, this rate case provides an opportunity for the Commission to do so.[1207]

[1204] 8 Tr 4844.
[1205] 8 Tr 4844.
[1206] 8 Tr 4844.
[1207] 8 Tr 4844, 4845; Exhibit AG-1.32.

Mr. Coppola asserts that the Commission should not be concerned that establishing an authorized ROE of 9.5% in this case will lead to the impairment of DTE's ability to access capital markets.

> In recent general rate case proceedings, the Commission seems to have been persuaded by the applicants' arguments that they should receive an ROE rate of 10% or higher to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. Pages 1 and 2 of Exhibit AG 1.32 show several utilities that have accessed the capital markets at competitive interest rates since receiving an ROE substantially below 10% as well as below the average rate of 9.45%.
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> Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-1.33 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs ranging from 8.38% to 9.90%. Yet this group of companies has an average ratio of Market price to Book common equity value of more than 2 times book value.[1208]

He argues that this information dispels the myth that DTE must receive an ROE rate above the industry average or it will face dire consequences in the financial markets. He adds that the fact that DTE needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to DTE, as other electric and gas utilities face the same issues and are able to raise capital with ROEs at or below his proposed 9.50%.[1209]

Finally, Mr. Coppola states that if the Commission were to grant a 9.90% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $45.5 million annually. He asserts that "there is absolutely no need to burden customers with

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[1208] 8 Tr 4845-4846; Attorney General brief, 91-92.
[1209] 8 Tr 4846; Exhibit AG-1.33.

this additional cost, when historically the Company has been earning well above its authorized ROE."[1210]

d. ABATE

Mr. Walters estimates the current fair market ROE for the DTE to fall within the range of 9.10% to 9.70%, with a midpoint of 9.40%.[1211]

Mr. Walters states that authorized ROEs for both electric and gas utilities have declined over the last 10 years and have been below 10.0% for about the last nine years. He adds that the distribution of authorized returns annually since 2016 shows that over the last few years, the majority of authorized ROEs since 2016 have been below 9.7%, with many of those being below 9.5%.[1212] Noting that the Commission has previously stated that the fact that other utilities have been able to access capital using lower ROEs "is a relevant consideration,"[1213] Mr. Walters asserts that utilities have been able to access external capital to support capital expenditure programs. He states that the credit rating for the electric utility industry has improved over the last 10 years as the result of marked improvement in overall financial health and credit quality in the industry, and that a significant majority (73%) of the electric utility companies have bond ratings in the range of BBB+ to A-. He adds that capital expenditures for electric and natural gas utilities have increased considerably over the period 2020 into 2021, and the forecasted capital expenditures remain elevated through 2022, albeit falling below current levels in 2023. He asserts that "[t]his is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt

[1210] 8 Tr 4846.
[1211] 8 Tr 3046.
[1212] 8 Tr 3047, 3048, 3049.
[1213] ABATE brief, 58.

capital to the utility industry in a manner that allows for these elevated capital investments," and that "regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service but at competitive tariff prices."[1214]

Mr. Walters states that the historical valuation of electric utilities followed by the Value Line Investment Survey ("Value Line") indicates utility security valuations today are very strong and robust relative to the last several years. He adds that robust valuations are an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. Mr. Walters states that while authorized ROEs have fallen to the mid 9.0% range, utilities continue to have access to large amounts of external capital even as they are funding large capital programs. Furthermore, over the last decade, utilities' credit ratings have been mostly stable and have improved due, in part, to supportive regulatory treatment.[1215] Noting that authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic, he asserts that "it is critical that the Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity."[1216]

Mr. Walters states that the actions of the Federal Reserve are known to market participants, such that it is reasonable to believe that those actions are reflected in the market's valuation of debt and equity. He adds that during the period between

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[1214] 8 Tr 3051-3053.
[1215] 8 Tr 3054; Exhibit AB-11.
[1216] 8 Tr 3055.

December 2015 and December 2018 when the Fed raised the short-term rate nine times, a corresponding increase in long-term Treasury yields and A-rated utility bond yields did not materialize. He argues that this is an important observation to consider as the Fed is expected to raise short-term rates in the near-term in order to manage inflation and support employment in the economy.[1217]

Mr. Walters states that independent economists expect the current low capital costs to prevail over at least the intermediate term, and that there is a clear trend in forecasted changes in interest rates over time, indicating that capital market participants are becoming more comfortable with today's low-cost capital market environment and expect it to prevail over at least the intermediate future.[1218] He concludes that:

> [T]he outlook for increases in interest rates has jumped more recently relative to 2020, but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. Indeed, today's relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. While there is potential for some upward movement in the cost of capital, that upward movement is uncertain. In fact, as shown on Figure CCW-3 above [8 Tr 3056], increases in the Federal Funds Rate do not necessarily translate into increases in longer term yields.[1219]

Mr. Walters states that the ongoing conflict in Ukraine and the economic sanctions levied on Russia have sparked a fair amount of volatility and uncertainty in capital markets around the world. However, he adds that historical evidence indicates that the impact on financial markets is generally transitory.[1220] He concludes by noting that since the end of the second quarter 2021, utilities in general, as measured by the S&P 500 Utilities index, have significantly outperformed the market as measured by the

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[1217] 8 Tr 3055, 3056.
[1218] 8 Tr 3058.
[1219] 8 Tr 3061.
[1220] 8 Tr 3061, 3062.

S&P 500, as well as the Nasdaq Composite, which he asserts is indicative that utility valuations remain robust, even during a period of elevated inflation, rising interest rates, and uncertainty as a result of the war in Ukraine.[1221]

Mr. Walters states that a utility's cost of common equity is the expected return that investors require on an investment in the utility, with investors expecting to earn their required return from receiving dividends and through stock price appreciation.[1222] Noting the Supreme Court's *Bluefield* and *Hope* decisions, Mr. Walters asserts that a fair rate of return is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level.[1223]

Mr. Walters estimates DTE's cost of common equity using (1) a constant growth DCF model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a CAPM, each of which he applied to a group of publicly traded utilities with investment risk similar to DTE.[1224]

Mr. Walters asserts that the market's assessment of DTE's investment risk is described by credit rating analysts' reports, and that DTE's current credit ratings from S&P and Moody's are A- and A2, respectively, and DTE has a 'Stable' outlook from both S&P and Moody's.[1225] Mr. Walters quotes from S&P's most recent report covering DTE, in part, as follows:

[1221] 8 Tr 3062.
[1222] 8 Tr 3063.
[1223] 8 Tr 3064.
[1224] 8 Tr 3064.
[1225] 8 Tr 3064.

> **Business Risk: Excellent**
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> Our assessment of DTEE's stand-alone business risk profile reflects the very low risk of the regulated utility industry, which provides indispensable services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly insulated from market challenges. DTEE benefits from supportive regulation in Michigan that provides for forward-looking rate cases and various riders that enhance cash flow predictability. . . .
>
> In addition, the predominance of residential and commercial customers restricts susceptibility to economic cyclicality and provides more stable operating cash flow. . . .
>
> **Financial Risk: Significant**
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> We assess DTEE's financial measures using our medial volatility table. This reflects the company's regulated electric utility operation and its effective management of regulatory risk in Michigan. Under our base-case scenario, we expect financial measures to be slightly above average within the range for the company's financial risk profile assessment. Specifically, we expect FFO to debt of about 19%-21% through 2022.
>
> . . . We expect DTEE will continue to fund its investments in a manner that preserves credit quality.[1226]

Mr. Walters relied on the same electric proxy group developed by Dr. Villadsen, but rejects her use of natural gas and water utilities to estimate the cost of equity for DTE. He notes that his proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody’s, respectively, while DTE’s credit ratings are one notch higher from S&P and three notches higher from Moody’s than those of the proxy group.[1227]

For his DCF analysis, Mr. Walters used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on April 15, 2022; the most recently paid quarterly dividend as reported in Value Line, annualized

[1226] 8 Tr 3065, quoting S&P RatingsDirect®: DTE Electric Co., September 8, 2021.
[1227] 8 Tr 3067.

and adjusted for next year's growth; and a consensus, or mean, of professional securities analysts' earnings growth estimates from: Zacks, MI, and Yahoo! Finance as a proxy for investors' dividend growth rate expectations. He states that the average growth rate for my proxy group is 5.61% and a median growth rate of 5.93%.[1228] He concludes that the average and median constant growth DCF returns for his proxy group for the 13-week analysis are 9.05% and 9.38%, respectively.[1229]

Mr. Walters adds that, using the average and median sustainable growth rates for the proxy group and using the internal growth rate model of 5.15% and 4.94%, respectively, his sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.58% and 8.51%, respectively.[1230]

For his multi-stage DCF model, Mr. Walters assessed three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year and extending into perpetuity, relying on the consensus of analysts' growth projections with adjustments and the consensus of projected GDP growth of about 4.10% over the next 10 years. [1231] He concludes that the average and median DCF ROEs for my proxy group using the 13-week average stock price are 7.81% and 7.88%, respectively.

From his three DCF analyses, Mr. Walters asserts that a reasonable ROE based on the DCF results is 9.1%.[1232]

[1228] 8 Tr 3069, 3070, 3071; Exhibit AB-13.
[1229] 8 Tr 3069, 3070; Exhibit AB-14.
[1230] 8 Tr 3072, 3073; Exhibit AB-16, Exhibit AB-17.
[1231] 8 Tr 3078; Exhibit AB-19.
[1232] 8 Tr 3078, 3079, Table CCW-8.

Regarding his bond yield plus risk premium model, Mr. Walters used two estimates of an equity risk premium; the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds, and the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. He states that adding the 5.59% risk premium to the 13-week A-rated utility bond yields of 3.82% produces an estimated cost of equity of 9.41% and adding the 5.59% risk premium to the 13-week Baa-rated utility bond yields of 4.09% produces an estimated cost of equity of 9.68%. He concludes that, based on the results of his analyses, a reasonable ROE based on his risk premium analysis is 9.7%.[1233]

For his CAPM analysis, Mr. Walters used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 3.30% for his market risk-free rate; used the current proxy group average and median Value Line beta estimates, the historical average of the proxy group's Value Line betas, and adjusted beta estimates as provided by Market Intelligence's Beta Generator model for his beta calculations; and used two versions of the constant growth DCF model to develop estimates of the market risk premium. His nine different applications of the CAPM resulted in three ranges as follows: 7.93% to 12.62%, 7.08% to 11.02%, and 6.57% to 10.05%. He concludes that the average of my CAPM results is approximately 9.45%, while the median is 9.76%, and thus recommends a CAPM return estimate of 9.6%.[1234]

[1233] 8 Tr 3079, 3080, 3081, 3082, 3083, 3084; Exhibits AB-21, AB-22, and AB-23.
[1234] 8 Tr 3084-3093, Table CCW-11; Exhibits AB-24, AB-25, and AB-26.

Based on his various analyses, Mr. Walters estimates DTE's current market cost of equity to be in the reasonable range of 9.10% to 9.70% with a midpoint estimate of 9.40%. He adds that given the differences in DTE's credit ratings relative to those of the proxy group, an ROE in the lower half of my range could be warranted.[1235] Mr. Walters asserts that his recommended overall rate of return will support an investment grade bond rating for DTE, based on comparing the key credit rating financial ratios for DTE at his proposed return on equity capital structure and DTE's embedded debt cost to S&P's benchmark financial ratios using S&P's credit metric ranges. He states that S&P evaluates a utility's credit rating based on an assessment of its financial and business risks, with a combination of financial and business risks equating to the overall assessment of DTE's total credit risk exposure. He notes that S&P publishes ranges for primary financial ratios that it uses as guidance in its credit review for utility companies, with the two core financial ratio benchmarks it relies on in its credit rating process being (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") and (2) Funds From Operations ("FFO") to Total Debt. Mr. Walters calculated each of S&P's financial ratios based on DTE's cost of service for its regulated utility operations in its Michigan service territory. Mr. Walters states that based on an equity return of 9.40% and DTE's proposed common equity ratio of 50.05%, DTE is estimated to produce a Debt to EBITDA ratio of 3.9x, which is within S&P's "Significant" guideline range of 3.5x to 4.5x. In addition, DTE's retail utility operations FFO to total debt coverage at a 9.40% equity return and 50.05% equity ratio is 20%, which is within S&P's "Significant" metric guideline range of 13% to 23%. Noting that this ratio is again

[1235] 8 Tr 3094.

within the FFO/total-debt range that will support DTE's credit rating, he concludes that DTE's core credit metrics ratios based on his recommended rate of return will support its investment grade credit rating of A-.[1236]

Mr. Walters states that Dr. Villadsen's recommended ROE of 10.25% is excessive and unreasonable for a low risk regulated utility company. He disagrees with her assertion that DTE's risk is higher than average relative to her electric sample and warrants a return in the upper end of her range.[1237] He states that the model ROE results of Dr. Villadsen's studies applied to her electric sample indicate that the required ROE is in the range of 8.0% to 10.1%, but notes that not one of her electric proxy group results (without her financial leverage adjustments) are as high as her recommendation of 10.25%. He adds that Dr. Villadsen then increases her market ROE estimate by adjusting her results upward in the range of 0.7% to 1.5% using an overall cost of capital ("OCC") methodology, which methodology he asserts is identical to the After-Tax Weighted Average Cost of Capital ("ATWACC") methodology. ABATE argues that the unreasonableness of the ATWACC adjustment is evidenced by the fact that the Commission has rejected its use numerous times, including in Case No. U-18014 in which the Commission agreed "that little or no weight should be given to the utility's ATWACC calculations."[1238]

Mr. Walters asserts that the book value common equity ratio of DTE indicates that it has a comparable amount of financial risk to that of the proxy group, if not

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[1236] 8 Tr 3094-3097; Exhibit AB-27.
[1237] 8 Tr 3098.
[1238] 8 Tr 3098-3100, citing U-18014 Order at 66, and U-18255 Order at 32. See, also, ABATE brief, 67-68.

less.[1239] He adds that Dr. Villadsen does not take into consideration that traditional ratemaking treatment of a utility's allowed ROE in the United States has supported strong investment grade credit ratings, ample external capital for a capital intensive industry, while market valuations for the publicly traded parent companies have sustained above book value for decades.[1240]

For her CAPM analysis, Mr. Walters notes that Dr. Villadsen proposes either one of two ROE adjustments: adding to her base CAPM return estimate an ATWACC ROE adjustment of approximately 150-160 basis points, which produces an ATWACC-adjusted CAPM return for her electric sample in the range of 10.8% to 11.5%, or a financial risk adjustment to reflect a leveraged beta adjustment, which adds approximately 110 to 150 basis points to the base CAPM return estimates. He argues that this leverage adjustment to the base CAPM return estimate produces an excessive and unreasonable ROE for DTE.[1241] In addition, he asserts that Dr. Villadsen's application of the Hamada adjustment in her CAPM and ECAPM analyses is inappropriate as the Hamada has not been shown to be applicable to an already-adjusted Value Line beta.[1242] He also states that Dr. Villadsen included an adjusted beta within her ECAPM studies, which adjustment is inconsistent with the academic research supporting the development of an ECAPM methodology. He concludes that there is no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate. [1243]

[1239] 8 Tr 3102; Exhibit AB-20.
[1240] 8 Tr 3103.
[1241] 8 Tr 3106.
[1242] 8 Tr 3107.
[1243] 8 Tr 3108, 3109.

Finally, Mr. Walters asserts that Dr. Villadsen has inaccurately assessed the risk of DTE relative to the proxy group. He states that Dr. Villadsen has cherry-picked risks potentially faced by DTE without considering other unique risks faced by the proxy group companies. He adds that to the extent ratings agencies deemed the particular risks cited by Dr. Villadsen as detrimental to DTE, ratings agencies would have taken them into consideration, and they would be reflected in DTE's credit ratings. He notes that DTE's ratings from both S&P and Moody's are higher than those of the proxy group.[1244]

e. MNSC[1245]

Mr. Garrett asserts that the Commission should reject DTE's proposed ROE of 10.25% as excessive and unsupported. An objective cost of equity analysis shows that DTE's cost of equity is about 7.4%. He states that it is not reasonable to award an ROE that is significantly above a regulated utility's cost of equity. He recommends the Commission award DTE an authorized ROE of 8.8%. Although 8.8% is still clearly above DTE's market-based cost of equity estimate, it represents a gradual yet meaningful move towards market-based cost of equity, and 8.8% is the midpoint between DTE's current authorized ROE of 9.9% and the cost of equity indicated by the CAPM, which is 7.7%. He adds that setting the awarded ROE far above the cost of equity results in an excess transfer of wealth from customers to the utility, which is never appropriate. Indeed, he asserts that there has been a trend with respect to

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[1244] 8 Tr 3111; Exhibit AB-12.

[1245] Mr. Garrett states that he submitted testimony in this matter on behalf of MEC and CUB. 8 Tr 3867. However, in its brief, MNSC, which includes the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and the Citizens Utility Board of Michigan, states that Mr. Garrett testified "on behalf of MNSC." MNSC brief, 60.

regulated utilities in which awarded returns fail to closely track with market-based cost of capital, and that, to the extent this occurs, the results are “detrimental to ratepayers and the state’s economy.”[1246]

Mr. Garrett states that the ratemaking concept of “gradualism,” though usually applied from ratepayers’ standpoint to minimize rate shock, could also be applied illustratively to shareholders, and that an awarded return as low as 7.4% would arguably represent a stark movement in the awarded ROE, considering that DTE’s current authorized ROE is 9.9%. He asserts that one of the primary reasons DTE’s actual cost of equity is so low is because DTE is a low-risk investment, as, in general, utility stocks are low-risk investments because movements in their stock prices are not volatile. Thus, if the Commission were to make a significant, sudden change in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing DTE’s risk profile, which could be in contravention to the *Hope* Court’s “end result” doctrine[1247]

Noting that Dr. Villadsen proposes a return on equity of 10.25%. and that her recommendation is primarily based on various versions of the CAPM and DCF Model, Mr. Garrett states that several of her key assumptions and inputs to these models violate fundamental, widely accepted tenets in finance and valuation, including the growth rates used in her DCF models, her inflated estimate for the equity risk premium (“ERP”) used in her CAPM analysis, and that she adds a “financial risk adjustment” to the results of her models, which inappropriately inflates the results.[1248]

[1246] 8 Tr 3868, 3872, 3873, 3877, 3878.
[1247] 8 Tr 3872-3873.
[1248] 8 Tr 3874, 3875.

Mr. Garrett states that he used the same proxy group of electric utilities used by Dr. Villadsen, and that conducting cost of equity analysis on a group of non-electric companies in this case adds no marginal value beyond the electric utility proxy group in terms of comparability. He notes that Dr. Villadsen also acknowledges that her ROE recommendation in this case "is fully supported by the electric sample results."[1249]

MNSC argues that risk is the "most important factor in determining awarded return", such that the awarded return in this case "should reflect DTE's relatively low market risk."[1250] Mr. Garrett states that public utilities are characterized as defensive firms that have low betas, have low market risk, and are relatively insulated from overall market conditions.

> Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle." Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions." In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. [Figure 4: Beta by Industry] . . . illustrates that the utility industry is one of the least risky industries in the U.S. market.
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> The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not fluctuate widely. So, while it is preferable for utilities to be defensive firms that experience little market risk and

[1249] 8 Tr 3885, 3886.
[1250] MNSC brief, 61.

relatively insulated from market conditions, this should also be appropriately reflected in DTE's awarded return.[1251]

For his DCF analysis, Mr. Garrett used a 30-day average of stock prices for each company in the proxy group, the most recent quarterly dividend paid for each proxy company, and a single terminal, long-term growth rate of between the expected rate of inflation and the expected rate of nominal GDP growth, thus between 2% and 4%.[1252] Noting that analysts' growth rate projections should not be utilized in a stable growth DCF model, Mr. Garrett used the maximum, reasonable long-term growth rate of 3.8%.[1253] His DCF Model cost of equity estimate for DTE is 7.1%.[1254]

Mr. Garrett states that the results of Dr. Villadsen's DCF Model are overstated primarily because of a fundamental error regarding her growth rate inputs and her financial risk adjustment. He states that Dr. Villadsen assumes projected long-term growth rates as high as 8.3% in her DCF Model, which is more than twice as high as long-term GDP growth projections. He adds that Dr. Villadsen relies on short-term, quantitative growth estimates published by analysts to support her assumptions, using growth rate projections that cover only a five-year period which is not sufficient for a long-term estimate.[1255]

For his CAPM analysis, Mr. Garrett considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury Bonds in his risk-free rate estimate, which resulted in a risk-free rate of 2.74%. For his beta, he used betas recently published by Value Line Investment Survey, with the average beta for the proxy group

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[1251] 8 Tr 3891, 3892, 3893.
[1252] 8 Tr 3894- 3903.
[1253] 8 Tr 3904-3908.
[1254] 8 Tr 3909; Exhibit MEC-41.
[1255] 8 Tr 3909-3911.

being 0.87. For his equity risk premium (ERP), Mr. Garrett uses the implied ERP method, whereby he calculated the dividend yield, buyback yield, and gross cash yield for each year, and calculated the compound annual growth rate from operating earnings. Using these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.6%, he subtracted the risk-free rate to arrive at the implied equity risk premium of 4.8%. For his final ERP estimate, Mr. Garrett considered the results of the ERP surveys along with the implied ERP calculations and the ERP reported by Duff & Phelps., and selected the highest ERP estimate of 5.5%. Using the inputs for the risk-free rate, beta coefficient, and ERP discussed above, Mr. Garrett estimates that DTE's CAPM cost of equity is 7.7%.[1256]

Mr. Garrett asserts that Dr. Villadsen's CAPM analysis is overstated because she used an unreasonably high input for the ERP and she applies an unreasonable financial risk adjustment to her results. In addition, Dr. Villadsen conducts an empirical CAPM ("ECAPM") in addition to the traditional CAPM, which suffers from the same unreasonable assumptions as her traditional CAPM.[1257] Mr. Garrett asserts that Dr. Villadsen relies on an unreasonable estimate of 7.89% for the ERP, while the highest ERP from his research and analysis is only 5.5%.[1258]

Mr. Garrett notes that Dr. Villadsen applies a financial risk adjustment to her CAPM "to reflect the fact that different capital structure ratios have different levels of financial risk." He asserts that the end result of Dr. Villadsen's financial risk adjustment is essentially suggesting the U.S. regulated utilities are more risky than the market

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[1256] 8 Tr 3911-3921; Exhibits MEC-42, MEC-43, MEC-44, MEC-45, and MEC-46.
[1257] 8 Tr 3922.
[1258] 8 Tr 3923-3924.

average, which is not a realistic assumption. Specifically, Dr. Villadsen assumes betas of greater than 1.0 in her adjusted CAPM, while companies with betas greater than 1.0 are more risky than the market average. He concludes that to suggest that DTE is riskier than the market average is not reasonable, noting that the average beta of the proxy group is 0.9.[1259] He adds that he believes that her financial risk adjustment under the Hamada method is inaccurate.[1260] Mr. Garrett states the problems related to Dr. Villadsen's ECAPM are essentially the same as those that exist in her traditional CAPM analysis, although he notes that the results of Dr. Villadsen's ECAPM do not appear to be substantially different than those of her traditional CAPM.[1261]

Mr. Garrett disagrees with Dr. Villadsen's suggestion that certain firm-specific risks and other factors should have an increasing effect on the cost of equity, beyond that which is accounted for in the CAPM and DCF Models, but he notes that Dr. Villadsen does not attach a specific, quantitative adjustment to account for these factors. He adds that the financial models presented in his testimony directly measure market risk, which is the type of risk the Commission should focus on when determining a fair authorized ROE.[1262]

Regarding Dr. Villadsen's other risk premium analyses, which considers allowed ROE's from prior rate cases dating back to 1990, Mr. Garrett disagrees with the premise of the analysis. Noting that it is clear that awarded ROEs are consistently higher than market-based cost of equity, and they have been for many years, he asserts that a model that simply compares the discrepancy between awarded ROEs and any market-

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[1259] 8 Tr 3924.
[1260] 8 Tr 3924-3927; Exhibit MEC-52.
[1261] 8 Tr 3927-3928.
[1262] 8 Tr 3928-3930.

based factor (such as bond yields) will simply ensure that discrepancy continues. In addition, he argues that the risk premium analysis offered by Dr. Villadsen is completely unnecessary when there already is a real risk premium model to use: the CAPM, which takes the bare minimum return any investor would require for buying a stock (the risk-free rate), then adds a premium to compensate the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security.[1263]

f. Walmart

Ms. Perry states that Walmart believes that DTE's proposed ROE of 10.25 percent is excessive, especially in light of: 1) the customer impact of the resulting revenue requirement increase, 2) the reduced risk associated with Michigan's regulatory framework and Commission precedent, including the (i) use of a projected test year (which reduces the risk due to regulatory lag based on the inclusion of the most current information in its rates when they will be in effect), and (ii) inclusion of CWIP in rate base; and 3) recent ROEs approved in Michigan and other jurisdictions nationwide. She notes that using DTE's proposed rate base, cost of debt, and capital structure, the impact of the proposed changes in authorized ROE alone is approximately $39.9 million, or 10.3 percent of the proposed revenue deficiency.

Ms. Perry notes that since 2019, this Commission has issued orders with stated ROEs in seven dockets, with the most recent ROE approved late last year, and with the average of these approved ROEs being 9.92%. She adds that the average of the 116 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities since 2019 is 9.45%, with the range of reported authorized ROEs for the period

[1263] 8 Tr 3931-3932.

being 7.36% to 10.60%, and the median authorized ROE is 9.50%. She concludes that the average and median values are significantly below DTE's proposed ROE of 10.25%.[1264] Ms. Perry states that assuming DTE's proposed rate base, cost of debt, and capital structure, authorizing DTE a ROE of 9.60% instead of the requested 10.25% would result in a reduction of about $74.1 million to the requested revenue requirement increase.[1265]

Noting that the Commission has previously recognized that Michigan's statutory framework contains several mechanisms which significantly reduce the risk borne by utilities, Walmart argues that the Commission "must take a conservative approach when awarding a specific ROE."[1266] Walmart asserts that the disparity between DTE's proposed ROE and the average ROEs awarded by this and other utility regulatory commissions over the past several years should "motivate the Commission to carefully examine the Company's proposed revenue requirement increase and the associated ROE and consider the impact of the authorized ROE on existing and prospective customers as well as the Company's ability to access capital and earn a fair return."[1267]

g. DAAO

Mr. Koeppel states that among all of the different entities that could pay for necessary upgrades to service and infrastructure, DTE "is in the best financial position to bear that burden because the problems are ones of DTE's own making."[1268] While asserting that the Commission could and should approve certain aspects of DTE's

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[1264] 8 Tr 4127-4129; Exhibit WAL-3.
[1265] 8 Tr 4131; Exhibit WAL-4.
[1266] Walmart brief, 4.
[1267] Walmart brief, 6.
[1268] 8 Tr 4329.

requests to address service and reliability failings, the Commission should not approve an increase in rates, "because then it would be requiring customers to pay for DTE's past and present failures."[1269] Mr. Koeppel states that if the Commission finds that all of the components of DTE's plan are reasonable and prudent but does not increase the rates, the resulting ROE for DTE would be 6.9% instead of DTE's requested 10.25%. He adds that while it would be a significant shift for the Commission to approve incremental spending but not incremental increases in rates, he asserts that it is "fully justified by the situation DTE has created", arguing that "[m]anagement that imposes soaring energy burdens is not, and should not be considered, efficient and effective, and that "management that creates persistently inadequate service is not efficient and effective." [1270]

Mr. Koeppel rejects DTE's assertion that its financial health and stability are good for customers due to the relationship between DTE's profitability and its ability to access low-cost capital, arguing that such claims are not dispositive for the Commission's decision on ROE even if true.

> First, whatever ROE DTE Electric should be allowed the "opportunity to earn" in the abstract, DTE has, in fact, not earned it. Considering ROE merely in terms of the Company's financial health divorces profitability from performance. DTE's approach is one of entitlement: under this theory, the Commission must award the Company a certain rate of return to satisfy the Company's investors, regardless of the Company's actual performance. Such an approach, however, abdicates the Commission's responsibility to ensure DTE is delivering affordable, reliable, clean, and equitable service.
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> Second, DTE's argument regarding benefit to customers is either circular or under supported. Paying a higher ROE to generate lower costs on debt

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[1269] Id.
[1270] 8 Tr 4330.

> is worthwhile for customers only if it results in lower net payments by customers. DTE does not quantify the effect of a change in ROE on debt financing cost or demonstrate that DTE would in fact be financially imperiled by a lower rate of return. Similarly, on DTE's theory, a low ROE presents a problem for customers with respect to the Company's equity financing only if the low ROE actually results in an inability for the Company to access additional equity financing. DTE's testimony elides the crucial distinction between what investors "expect" and what investors "require." All of the methods of market benchmarking that DTE puts forward speak merely to "the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk." DTE Energy's stock price may fall if DTE Electric cannot provide the returns that investors have expected. This is only natural, as the stock price reflects investor expectations. But that is quite different from an actual inability to raise additional equity.
>
> Third, DTE's argument that its financial health contributes to positive economic impacts on the communities it serves is not specific to DTE, is under-supported, and helps to generate a self-fulfilling prophecy. DTE lists various benefits that it provides to communities, but those benefits are simply the result of the provision of utility service. . . .[1271]

Regarding whether DTE's requested ROE is commensurate with the risks DTE faces, Mr. Koeppel asserts that the Commission should take note of how DTE portrays its risks to investors.

> DTE "crows to its shareholders" that Michigan is a "Tier 1" regulatory jurisdiction based on UBS's rankings. UBS designs these rankings based on a variety of regulatory factors that relate to a utility's ability to realize a higher rate or amount of return. In other words, a higher ranking would correlate to greater reliability of regulatory decisions that are in the Company's financial interest. Given DTE's ability to consistently receive confirmation or approval of expenses in contested rate cases or rapid ex parte approval of special rate requests even with parties from all rate classes requesting contested proceedings, DTE's approach asks for risk compensation while not actually presenting any meaningful risks to the Company.[1272]

[1271] 8 Tr 4334- 4335.
[1272] 8 Tr 4338-4339; Exhibits DAO-83 and DAO-84.

DAAO argues that DTE's requested increase of its ROE (as well as its residential rates) are "exceptionally high increases that are not justified by DTE's past actions or current proposal", and that the Commission "should not reward DTE with additional profit for beginning only now to address the long-standing gaps in its service quality".[1273]

h. MI MAUI and Ann Arbor

MI MAUI and Ann Arbor argue for a "below-average" return on equity due to a) substandard reliability performance that both lowers the value of DTE's service to customers and the lower value attributed to equipment that cannot provide reliable service, and b) other mechanisms through which DTE shareholders are profiting from lower reliability while worsening equity concerns.[1274]

> "[O]ne major purpose of regulation is…to insure so far as practical that Edison is in a similar position to enterprises in the competitive sector." *Detroit Edison Co v Pub Serv Com'n*, 127 Mich App 499, 523; 342 NW2d 273, 284 (1983), citing Order in U-4807 (March 30, 1976). One of the key aspects of duplicating competitive pressure is creating financial consequences for subpar performance. Statutorily, one of the ways the Commission must do this is to consider a number of factors when setting rates, including the "value of service to the customer" of the provision of those services. M.C.L. § 460.557(2).
>
> The record is replete with unrebutted testimony from customers regarding reduced value of DTE's services due to the Company's poor reliability.[1275]

MI MAUI and Ann Arbor argue that reliability issues include frequent and recurring power quality issues and streetlight service, and that the lower reliability is due to DTE's failures to properly plan or execute its plans.[1276]

> The history of the inadequate vegetation management programs shows that DTE management's failure to plan for climate change was and is a

[1273] DAAO brief, 77.
[1274] MI-MAUI brief, 2-3.
[1275] MI-MAUI brief, 5-6.
[1276] MI-MAUI brief, 7-8, 11.

> contributing factor to the Company's failure to offer reliable power to its customers. That in turn is a key driver of lowering the value of its services to the customer and the lower value of their equipment as a whole. The Commission must consider not only DTE's considerable efforts to "catch up" on tree trimming, but the results of its efforts. For nearly a decade now, customers have suffered from below-average reliability. This outcome is worse than peer utilities, was foreseeable, and was preventable. Increased storm events and the need to stay on top of and accelerate tree trimming were entirely foreseeable in 2013. Management decisions not to take into account these factors in their O&M planning contributed to DTE's poor reliability. Other utilities kept up with trimming and did plan for increased storms. Therefore, it is appropriate that the return on investment the Company receives would mirror what would happen in a competitive marketplace, and be lower when compared to its peers. Those peers demonstrate both better planning and better customer outcomes, despite similar levels of executive compensation.[1277]

MI MAUI and Ann Arbor argue that any protestation that a lower ROE than average will hurt the ability for DTE to earn a reasonable return on investment should be balanced by consideration of shareholders' efforts to profit from poor reliability.[1278]

i. Rebuttal

In rebuttal, Dr. Villadsen reiterates many of the assertions she made in her direct testimony. Dr. Villadsen states that Staff's and the intervenor's recommended ROEs are "too low in today's financial environment".[1279] In her summary comparison of Staff's and the intervenor's (the Attorney General, ABATE, MNSC) recommended ROEs, she lists her "needed adjustments", for each of the four other recommended ROEs to account for financial leverage factors.[1280] She notes that all intervenors except Staff propose ROEs lower than 9.52%, which is the average ROE for vertically integrated electric companies

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[1277] MI-MAUI, 18.
[1278] MI-MAUI, 18.
[1279] 7 Tr 1399.
[1280] 7 Tr 1401.

from 2021 through May 20, 2022.[1281] She adds that the inflationary environment and increasing interest rates makes the recommendations of the intervenors outside the range of reasonable ROEs.[1282]

Dr. Villadsen asserts that Mr. Garrett, Mr. Ufolla and Mr. Walters use data for the period ended 2020, and that all witnesses filed their testimonies on May 19, 2022 when fiscal year 2021 data would have been available. Thus, she argues that these witnesses rely on dated information that does not reflect the most recent capital markets environment.[1283] For example, regarding the risk free rate:

> Mr. Garrett and Mr. Ufolla's estimates are too low, given that they filed testimony on May 19, 2022. By May 19, 2022, the Federal Markets Open Committee had raised benchmark rates by 75 basis points since January 2022. The risk free rates used by Mr. Garrett and Mr. Ufolla should have included the most recent forecasts at the time of their testimonies, and they did not. Instead, Mr. Garrett used an average of the risk free rates over the prior 30 days from May 2, 2022, as opposed to taking the most recent May 2 forecast, which was 3.07 percent; Mr. Ufolla uses a similar technique, taking an average of risk free rates as opposed to the most recent. Using risk free rates lower than actually observed leads both witnesses to underestimate DTE Electric's ROE. This is particularly an issue when interest rates increase (or decrease) and are expected to remain at that trajectory.[1284]

Dr. Villadsen summarizes and compares Staff's and the intervenor's assumptions (inputs) with her assumptions, asserting hers are the right ones to use.[1285] Dr. Villadsen argues that DTE's credit ratings do not indicate an assessment of DTE's overall riskiness:

> [c]redit ratings measure credit risk, while equity investors are considering the return that is available on alternative investments of similar equity risk.

[1281] 7 Tr 1401-1402; Exhibit A-47, LL 1.
[1282] 7 Tr 1402.
[1283] 7 Tr 1404.
[1284] 7 Tr 1405-1406.
[1285] 7 Tr 1405, Table 2.

> That is, credit rating agencies do not assess general riskiness of companies; they assess default risk. Because DTE has a higher credit rating than other electric sample peers simply indicates that it is at lower risk of default. Such ratings do not speak to the overall equity riskiness of the company. Specifically, S&P states: "Credit ratings … are not indications of investment merit…the ratings are not buy, sell, or hold… or a measure of asset value… they speak to one aspect of an investment decision – credit quality…" Therefore, Mr. Walters assertion that DTE's credit rating has implications for the riskiness of its ROE is unfounded.[1286]

Regarding ECAPM, Dr. Villadsen asserts that the ECAPM has merit, that there is no double counting in using adjusted betas in the ECAPM, and that it results in an estimation of ROE that is close to the traditional CAPM.[1287]

j. Findings and Recommendations

In reviewing the different analyses presented by the witnesses, and mindful of the principles enunciated in *Bluefield* and *Hope, supra,* this PFD finds that DTE's recommended return of 10.25% is excessive, is not supported by the record evidence, and thus should be rejected for the following reasons.

First, DTE's own analysis of the cost of equity methodologies is flawed. While Dr. Villadsen utilized the DCF and the CAPM/ECAPM models to estimate an appropriate ROE, she "adjusted for differences in financial risk" due to different levels of financial leverage among the proxy companies and differences between the capital structures of the proxy companies and the regulatory capital structure applied to DTE for ratemaking purposes.[1288] These adjustments were made pursuant to the application of the 1)

[1286] 7 Tr 1411. See also, 7 Tr 1444-1445.
[1287] 7 Tr 1426.
[1288] 7 Tr 1314.

overall cost of capital approach (applied to her DCF analysis) and 2) the Hamada approach (applied to her CAPM/ECAPM analysis).[1289]

These adjustments significantly increased Dr. Villadsen's calculated ROE percentages under her DCF and CAPM methodologies. Indeed, Dr. Villadsen testified that the failure of Staff and intervenors to make these financial leverage adjustments reduced their respective ROE estimates "by at least 150 basis points."[1290] Mr. Coppola asserts that these adjustments by Dr. Villadsen increased her DCF results by 1% and her CAPM results by 1.5% - 1.6%.[1291] Mr. Walters calculates Dr. Villadsen's adjustments as ranging from .7% - 1.0% for the DCF model and 1.5% for the CAPM calculation.[1292]

Staff, the Attorney General, ABATE and MNSC assert that DTE's financial leverage adjustments are unnecessary, inappropriate, and have previously been rejected by the Commission. This PFD agrees. See, Order, U-18014, January 31, 2017, p. 66 ("[T]he Commission does agree with the PFD that little or no weight should be given to the [DTE's] ATWACC calculations."); Order, U-18255, April 18, 2018, p. 32 (same); Order, U-20940, December 9, 2021, p. 91:

[1289] 7 Tr 1430. There is some inconsistency with respect to the description of the cost of capital adjustment. Mssrs. Ufolla and Coppola refer to this adjustment as an After-Tax Weighted Average Cost of Capital (ATWACC) approach. 8 Tr 5091, 8 Tr 4828. Mr. Walters initially describes this adjustment as an "overall cost of capital ("OCC") methodology" and after stating that the OCC method used by Dr. Villadsen is "identical" to the ATWACC methodology, uses these terms interchangeably.8 Tr 3099; 3100, n. 33; 3101. In her Appendix B to her direct testimony, Dr. Villadsen refers to this as an "overall cost of capital ("OCC")". 7 Tr 1388-1389. However, in her rebuttal testimony, Dr. Villadsen notes the challenges by Mssrs. Ufolla, Coppola, and Waters to her use of the "ATWACC adjustment", does not dispute or rebut that the OCC and ATWACC are essentially the same, and defends her calculation of "after-tax weighted average cost of capital." 7 Tr 1389-1391. Thus, this PFD considers the referenced OCC and ATWACC adjustments to be the same.

[1290] 7 Tr 1440, Table 4

[1291] 8 Tr 4828, 4833.

[1292] 8 Tr 3099, Table CCW-13.

> The Commission concurs with the ALJ's observation that "the Commission has consistently taken a traditional approach to establishing ROE, focusing on thye most commonly used, fundamental approaches to determining a just and reasonable ROE, consistent with the principles of *Hope Natural Gas* and *Bluefield Waterworks*. . . In addition, the Commission acknowledges the Staff's and Attorney General's concern that consistent application of an ATWACC or Hamada adjustment may excessively inflate ROE's, stock prices, and market-to-book ratios for utilities.

Thus, DTE's financial leverage adjustments do not apply and should not be recognized. As such, as Mr. Ufolla testified, when the financial adjustments DTE uses are removed, the outputs are much lower and more in line with Staff's ROE recommendation.[1293] Indeed, Mr. Ufolla states that Staff does not object to the averages of the unadjusted CAPM outputs (9.10% and 9.64%) from DTE's Exhibit A-14, Sch. D5.10 being considered in the determination of a reasonable ROE.[1294] Similarly, Mr. Walters states that Dr. Villadsen's own calculated assessments, without her financial leverage adjustments, result in an ROE range of 8.0% -- 9.9%.[1295]

Dr. Villadsen stated that the average of the low and high estimates for DTE's CAPM/ECAPM, DCF, and Risk Premium methodologies for its electric proxy group resulted in a range of 9.9% - 10.6%, with her recommended ROE being 10.25%, the mid-point of this range. However, this PFD notes that if her CAPM average is reduced by 1.5% and her DCF average is reduced by 1% -- as approximately reflective of the increases because of DTE's financial leverage adjustments – DTE's ROE range is reduced to 9.0% -- 9.9%, with the mid-point being 9.5% (rounded).

[1293] 8 Tr 5096.
[1294] 8 Tr 5096-5097, Chart 3: DTE's Unadjusted CAPM Outputs.
[1295] 8 Tr 3099-3100, Table CCW-13.

Second, DTE has a favorable credit rating which will allow it to maintain access to capital markets and meet its financial obligations. Mr. Ufolla states that DTE currently has an A- rating from S&P, an Aa3 rating from Moody's, and an A+ rating from Fitch.[1296] He adds that these ratings are unchanged since DTE's last rate case[1297] and that all of DTE's ratings have a stable outlook.[1298] Similarly, Mr. Coppola testified that DTE's senior secured debt ratings are A/Aa3 and its commercial paper program is rated P-1 (highest) by Moody's Investor Service.[1299] He adds that DTE's access to the capital markets has remained strong as witnessed by DTE Electric's issuance in April 2021 of $425 million of new 30-year long-term debt at a rate of 3.25% and $575 million of 7- 10 year debt at a 1.9%, and that the DTE's parent, DTE Energy, accessed the capital markets in November 2021 issuing approximately $280 million of 60-year long-term debt at a rate of 4.375%.[1300] Mr. Walters states that DTE's current credit ratings from S&P and Moody's are A- and A2, respectively, and that DTE has a 'Stable' outlook from both S&P and Moody's.[1301]

Dr. Villadsen disputes Mr. Walters assertion that DTE is less risky as evidenced by DTE's credit rating being higher than the peer group.

> First, with regard to Mr. Walters comment that DTE Electric's credit ratings are higher than the peer group and therefore DTE Electric is less risky, credit rating agencies do not assess general riskiness of companies; they assess default risk. Because DTE Electric has a higher credit rating than other electric sample peers simply indicates that it is at lower risk of

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[1296] 8 Tr 5086.
[1297] DTE Electric's last rate case, U-20561, was filed on July 8, 2019 and resulted in the Commission's Order dated May 8, 2020. 7 Tr 1308-1309. This PFD notes that the period from the last rate case to present includes the beginning of the Covid-19 pandemic beginning in the spring of 2020 to date. Id.
[1298] 8 Tr 5086.
[1299] 8 Tr 4838.
[1300] 8 Tr 4838.
[1301] 8 Tr 3064.

> default. Such ratings do not speak to the overall equity riskiness of the company.
>
> Specifically, S&P defines credit ratings as “opinions about credit risk… the agency’s opinion about the ability and willingness of an issuer… to meet its financial obligation in full and on time.” Further, S&P states: “Credit ratings … are not indications of investment merit…the ratings are not buy, sell, or hold… or a measure of asset value… they speak to one aspect of an investment decision – credit quality…” Therefore, Mr. Walters assertion that DTE’s credit rating has implications for the riskiness of its ROE is unfounded.

Dr. Villadsen’s assertions in this regard are incorrect; credit ratings do assess the overall equity riskiness of the company. Dr. Villadsen states that when estimating the cost of equity, two categories of risk that are important business risk and financial risk.[1302] And credit reports assess both business risk and financial risk. As Mr. Walters states, “the market’s assessment of DTE’s investment risk is described by credit rating analysts’ reports.”[1303] He adds that “S&P evaluates a utility’s credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of DTE’s total credit risk exposure. On November 19, 2013, S&P updated its methodology, [publishing] a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.”[1304]

Indeed, S&P’s most recent report on DTE includes its assessment of both DTE’s business risk and financial risk, providing in part, as follows:

> **Business Risk: Excellent**
>
> Our assessment of DTEE's stand-alone business risk profile reflects the very low risk of the regulated utility industry, which provides indispensable

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[1302] 7 Tr 1312.
[1303] 8 Tr 3064.
[1304] 8 Tr 3095.

> services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly insulated from market challenges. . . .
>
> **Financial Risk: Significant**
>
> We assess DTEE's financial measures using our medial volatility table. This reflects the company's regulated electric utility operation and its effective management of regulatory risk in Michigan. . . [1305]

This S&P credit report confirms that DTE's business risk reflects the "very low risk" of the regulated utility industry, which provides "indispensable" and "strategically important" services, while essentially operating as "a monopoly insulated from market challenges."[1306] Similarly, S&P provides that DTE's financial risk is assessed under S&P's "medial volatility" table, with DTE's financial measures expected to be "slightly above average" within DTE's financial risk profile, and with DTE expected to continue to "fund its investments in a manner that preserves credit quality".[1307]

Dr. Villadsen acknowledges that DTE Electric has an A- credit rating from S&P, which is "comparable" to those of the proxy companies.[1308] This statement is misleading; DTE's A- credit rating is one level below one other proxy company credit rating, is the same level as six other credit ratings, and, most significantly, is better than the credit ratings of 20 proxy companies.[1309]

DTE argues that this is a "particularly inopportune time to weaken [DTE's] credit metrics due to the need for capital spending."[1310] However, DTE has not presented any analysis of its current or projected credit metrics or rating. Conversely, the Attorney

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[1305] 8 Tr 3065.
[1306] 8 Tr 3065.
[1307] 8 Tr 3065.
[1308] 7 Tr 1353.
[1309] See, Exhibit AB-12.
[1310] DTE brief, 167.

General has provided evidence that a reduction of DTE's authorized ROE to the level recommended by Staff, the Attorney General and ABATE will not adversely affect DTE's credit rating.

> Moody's rates the Company's debt as "Aa" and views the Michigan regulatory environment as constructive. A review of the most recent Moody's report on DTEE shows that the Company achieved a 22.4% CFO pre-WC to Debt ratio in 2020. This is a key ratio that Moody's uses to evaluate the Company's credit worthiness. It is Moody's position that ratio results under 20% for a sustained time could lead to a downgrade of the Company's debt.
>
> In Exhibit AG-1.35, I calculated a pro-forma CFO pre-WC to Debt ratio based on the Company receiving and earning an ROE rate of 9.50%. The calculations in the exhibit start with the actual ratio for 2020 and the adjustments needed to reflect a 50% common equity ratio and a 9.50% ROE rate. After making these adjustments the CFO pre-WC to Debt ratio would decline by an insignificant percentage from 22.4% to 22.2%, which is well above the 20% long-term downgrade threshold set be Moody's.[1311]

Mr. Walters does as well. Noting that the two core financial ratio benchmarks S&P relies on in its credit rating process are 1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and 2) Funds From Operations ("FFO") to Total Debt, he calculated each of S&P's financial ratios based on DTE's cost of service for its regulated utility operations in its Michigan service territory.[1312] He states that based on an equity return of 9.40% and DTE's proposed common equity ratio of 50.05%, DTE is "estimated to produce a Debt to EBITDA ratio of 3.9x", which is "within S&P's 'Significant' guideline range of 3.5x to 4.5x."[1313] In addition, he states that DTE's retail utility operations FFO to total debt coverage at a 9.40% equity return and 50.05% equity ratio is 20%, which is "within S&P's 'Significant' metric guideline range of 13% to

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[1311] 8 Tr 4840-4841; Exhibit AG-1.35.
[1312] 8 Tr 3095.
[1313] 8 Tr 3096.

23%."[1314] Thus, he concludes that "DTE's core credit metrics ratios" based on [his] recommended rate of return "will support its investment grade credit rating of A-."[1315]

Finally, this PFD notes that the most recent S&P credit report on DTE provides that S&P "expect[s] FFO to debt of about 19%-21% through 2022," which S&P considers to be "slightly above average" within the range for DTE's financial risk profile.[1316]

As to DTE's capital spending, the impact of such spending is assessed by the credit reporting agencies. Standard and Poor's latest credit report for DTE does not express a concern regarding DTE's capital expenditures. Rather, as indicated, S&P expects that DTE "will continue to fund its investments in a manner that preserves credit quality."[1317]

Noting that regulatory policy "plays a role in assessing its business risk", DTE asserts that the fact that DTE Electric does not have a revenue decoupling mechanism or a fixed variable pricing policy in place "puts it at an increased risk of under-recovering its cost of service relative to some companies in the sample group that benefit from such mechanisms."[1318] However, DTE's assertions in this regard are misleading, as these overlook other beneficial mechanisms that are available to DTE but not to other of the proxy sample companies. In asserting that DTE is thereby at an increased risk "relative to *some* companies in the sample group", DTE is acknowledging that some other companies within DTE's 27-company sample group also do not have a revenue

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[1314] 8 Tr 3097.
[1315] 8 Tr 3097.
[1316] 8 Tr 3065.
[1317] 8 Tr 3065.
[1318] 7 Tr 1353.

decoupling mechanism. Moreover, DTE acknowledges that DTE benefits from certain regulatory policies including a forward test year for rate cases and an annual PSCR clause for expenses such as fuel, capacity, energy, transmission, and purchased power, which cost-tracking mechanisms are in effect in states affecting "*several* of the sample companies," which implicitly acknowledges that these policies are not available for many more of the sample companies.[1319] Most significantly, Michigan's "regulatory policy" is scrutinized and evaluated by the credit reporting agencies, with S&P's latest report on DTE specifically providing that DTE "benefits from supportive regulation in Michigan that provides for forward-looking rate cases and various riders that enhance cash flow predictability."[1320]

DTE also asserts that it is "of higher than average business risk" relative to the sample proxy companies due to the Detroit area's economy having been hit "pretty hard" as evidenced by the Detroit metropolitan area's unemployment rate being 6.2%, while the national average is 5.9%.[1321] DTE also asserts that its ownership of the Fermi 2 Nuclear Generating Plant increases DTE's total risk.[1322] Again, this is misleading. DTE acknowledges that Michigan currently is expected to see a very high growth in the general economy (GDP).[1323] DTE also acknowledges that empirical tests of the effects of the ownership of nuclear generating plants on the cost of capital have not shown a statistically significant increase in the cost of capital.[1324] Mr. Coppola asserts that the difference in unemployment rates between Detroit versus the national average is

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[1319] 7 Tr 1352.
[1320] 7 Tr 3065.
[1321] 7 Tr 1354.
[1322] 7 Tr 1354.
[1323] 7 Tr 1354.
[1324] 7 Tr 1354.

immaterial as only 10% of DTE's sales to residential customers are in the City of Detroit and as many of the other utilities in DTE's proxy sample group also serve urban areas with depressed economic areas.[1325]

Most significantly, the credit reporting agencies evaluate these types of factors when assessing a company's credit rating, and again, DTE's credit ratings in comparison to the ratings of the proxy sample companies shows that DTE does not have a higher business risk than that of its peers.

Finally, as noted above, this PFD takes notice that several other intervenors also urge the Commission to reject DTE's recommended ROE as excessive and unsupported by the record.

In conclusion, this PFD finds that DTE has failed to justify a higher return on equity for the projected test year. DTE's estimated ROE calculations with the improper financial leverage adjustments removed are in the range of those calculations submitted by Staff, the Attorney General, and ABATE. DTE has not shown an increased risk attributable to the expected market conditions and presented no analysis of its current or projected credit metrics.

Conversely, as set forth above, Staff and other intervenors have provided significant evidence in support of the range made up of ROE's recommended by Staff (9.6%), the Attorney General (9.5%), and ABATE (9.4%). Moreover, unrebutted evidence has been presented which indicates that DTE 1) has very strong credit ratings – better than a large majority of the electric proxy group – 2) has relatively minimal business and financial risk, and 3) is able to attract capital. Moreover, Mr. Ufolla testified

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[1325] 8 Tr 4841.

that recent authorized ROE's for electric utilities by other state commissions – the average authorized ROE decisions for 2020 were 9.44% and 9.38% for 2021 – are within, and thus are supportive of, this range of recommended ROE's in this case.[1326] As such, this PFD finds that the ROE's recommended by Staff (9.6%), the Attorney General (9.5%), and ABATE (9.4%) are reasonable and supported by the record.

However, consideration must be given to certain concerns raised by DTE. As Dr. Villadsen testified in rebuttal:

> In the 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 2022 raised interest rates by 25 basis points, and then again by 50 basis points most recently in May 2022. This was the first "tightening" since December 19, 2018. This year, more tightening is anticipated, with the funds rate projected to reach 3.0 percent by late 2023. Further, as acknowledged by Mr. Walters, the Russian army invaded Ukraine on February 24, 2022. The ongoing war resulted in increased uncertainty regarding oil and agricultural prices. Consistent with these events, Blue Chip Economic Indicators (BCEI) now project inflation at 6 percent this year, up from 4.2 percent just a month ago. Further, forecasts for U.S. GDP growth have declined, where first quarter of 2022 reported negative GDP growth of 1.4 percent, raising questions of a "recession" for many consumers.[1327]

DTE, the credit rating agencies, Staff, the Attorney General, other interested parties and the Commission will need to wait to more fully assess the extent of the impact, if any, of these changes on the economy in general and on DTE's financial metrics specifically. This PFD is mindful of the direction the Commission provided in its March 29, 2018 order in Case No. U-18322: "it is not realistic to make a significant change in ROE

[1326] 8 Tr 5100; 8 Tr 4839-4840; Exhibit AG-1.32.

[1327] 7 Tr 1428-1429. Emphasis in original. This PFD is compelled to note that DTE in its reply brief also suggests that "[t]he Commission might take further notice of more recent events including a 75-basis point increase in June 2022, and most recently another 75-basis point interest rate increase in July 2022." DTE reply brief, 128. These referenced increases were not referenced in either DTE's direct testimony or its rebuttal testimony and are not part of the evidentiary record. As such, it is improper for DTE to ask this ALJ and the Commission to consider this information in this case.

absent a radical change in the underlying economic conditions."[1328] Thus, although generally supported by the evidence in this case, this PFD finds that the ROEs recommended by Staff, the Attorney General, and ABATE should not be adopted at this time. Rather, this PFD recommends that the Commission should keep DTE's authorized ROE at 9.90%. This return is based upon an objectively reasonable analysis consistent with past Commission decisions and the requirements of *Bluefield* and *Hope*, while at the same time acknowledging the potential disruption to the economy that increased interest rates and inflation may cause. This PFD concludes that such an ROE will assure reasonable access to capital on reasonable terms and conditions, while also remaining cognizant of the burden on ratepayers. In the absence of guidance from the Commission, this PFD does not take into account DTE's performance in terms of reliability or other measures of customer service.

Accordingly, this PFD recommends the Commission authorize an ROE of 9.90% for DTE.

2. Long-Term Debt Cost Rate

DTE projected a long-term debt cost rate 3.69% as shown in Exhibit A-14, Schedule D-2.[1329] Staff and the Attorney General agree.[1330]

3. Short-Term Debt Cost Rate

DTE projected a short-term debt cost rate of 1.74%.[1331] Staff and the Attorney General agree.[1332]

[1328] March 29, 2018 order, page 44.
[1329] DTE brief, 157, citing 7 Tr 1284, 1291-1292, 1295.
[1330] 8 Tr 5085; 8 Tr 4818.
[1331] DTE brief, 158, citing 7 Tr 1284, 1293, 1295; Exhibit A-14, Schedule D3.
[1332] 8 Tr 5085; 8 Tr 4818.

C. Overall Rate of Return

Based on the foregoing discussion, this PFD recommends that the Commission adopt DTE's capital structure and common equity balance, along with a long-term debt cost of 3.69%, a short-term debt cost of 1.74%, and a return on equity of 9.9%, resulting in an estimated overall weighted after-tax cost of capital of 5.42% as shown in Appendix D to this PFD.

VII.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) constitutes the difference between a company's operating revenue at current rates and its operating expenses including depreciation, taxes, and allowance for funds used during construction (AFUDC). Adjusted net operating income (ANOI) includes the ratemaking adjustments to the recorded test year NOI for projections and disallowances. DTE's filing projected an ANOI of $899.2 million, while Staff projected an ANOI of $988.6 million.

D. Operating Revenue

1. Sales forecast

Mr. Leuker provided testimony explaining DTE's sales forecasts and the methods used for projecting sales. He testified that the utility projected sales of 45,047 GWh during the test period.[1333]

On behalf of Staff, Mr. Ausum testified that the utility's projection was reasonable "for the most part," but that Staff created a model of sales for the residential bundled

[1333] 7 Tr 2630; See also Exhibit A-15, Schedule E1, p 1, line 2.

and C&I bundled customer classes that yielded a slightly higher projection than the one proposed by DTE.[1334] Given Staff's higher projections for those customer classes, Staff proposed an upward adjustment of 157 GWh, for a total of 45,204 GWh, which is 0.35% higher than the company's projection.[1335] Mr. Ausum explained the forecast methodology used by Staff, and he opined that Staff's forecast took advantage of more recent data, and therefore captured a clearer picture of electricity usage in the projected test year.[1336]

Mr. Coppola opined that DTE's forecast for residential customers was "unreasonably low."[1337] He asserted that contrary to the utility's assumptions, usage data showed that many customers continued to work from home despite the end of many pandemic-related disruptions, and residential sales still "surged" in 2021 compared to their already elevated levels in 2020 during pandemic-related lockdowns.[1338] Mr. Coppola contended that DTE's projected decline in residential sales during the test period was unwarranted given the continued high average usage per residential customer.[1339] Mr. Coppola explained that the decline in residential usage forecast by the company was largely caused by the so-called "wedge" adjustment described by Mr. Leuker in the company's forecast.[1340] Mr. Coppola explained that through discovery, he learned that the company's wedge adjustment utilized data from community mobility reports sourced from Google Maps to draw a correlation between

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[1334] 8 Tr 5469.
[1335] 8 Tr 5470; See also Exhibit S-20, pages 1-3.
[1336] 8 Tr 5470-5473.
[1337] 8 Tr 4850.
[1338] 8 Tr 4848, 4849.
[1339] 8 Tr 4849-4850.
[1340] 8 Tr 4850-4851.

electricity usage and the movement of individuals to and from homes and business locations.[1341] He opined that DTE's adjustment using mobility data is a novel and speculative approach, but that "it is not a proven methodology."[1342] Mr. Coppola argued that the company presented no back testing or direct connection showing that individuals moving between locations will ultimately affect electricity sales.[1343]

Mr. Coppola calculated an alternative forecast for residential sales using the most recent average customer data from 2021 and adjusting for EWR, DG, and EV adoption, which yielded an increase of 796.4 GWh (for a total of 45,843.4 GWh) compared to the company's forecast.[1344] He recommended that the Commission should "reject the company's novel and unproven approach" and should instead accept his approach and include $52,653,407 of additional revenue in this rate case to reduce the company's calculated revenue deficiency.[1345]

In rebuttal, Mr. Leuker asserted that Mr. Coppola's contention that there was an increase in residential use per customer in 2021 "is true, but is misleading in identifying the trends in sales during the COVID-19 pandemic."[1346] Mr. Leuker stated that for an accurate comparison, it was appropriate "to only look at the months in which COVID-19 related policies were present," i.e. to only compare the months of March through December of 2020 with March through December of 2021.[1347] In comparing those timeframes, Mr. Leuker noted that there was actually a decrease of -0.3% in residential

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[1341] 8 Tr 4851; See also Exhibit AG-1.37.
[1342] 8 Tr 4851.
[1343] 8 Tr 4851.
[1344] 8 Tr 4852; See also Exhibit AG-1.38.
[1345] 8 Tr 4853.
[1346] 7 Tr 2634.
[1347] 7 Tr 2634.

use-per-customer, which was consistent with the company's expectation that residential use would decrease as people returned to workplaces.[1348] Further, Mr. Leuker rejected the claim that the company did not provide evidence or back-testing to show that mobility data was an accurate predictor of sales. He stated that industry forecasting groups recommended using mobility data as a reasonable way to address emerging pandemic related sales variances, and that the company provided an out-of-sample test statistic for the first six months of 2021 showing that the model was only 93.7% accurate without mobility data, but that it yielded a result that was 99.5% accurate after including mobility data.[1349]

Mr. Leuker critiqued the alternative forecast offered by Mr. Coppola as an oversimplification that ignored trends in appliance saturation, natural efficiencies, economic activity, and consumer behavior resulting from the recent pandemic.[1350] Additionally, he asserted that unlike the company's consistent, industry-standard methodology, Mr. Coppola repeatedly changed his method to forecast residential sales over the last four rate cases, which Mr. Leuker contended was "unjustified, arbitrary, and lends itself to outcome-based data mining."[1351]

Mr. Leuker disagreed with Staff's recommended adjustments to forecasts for residential bundled and C&I bundled customers. He specified that Staff reduced the forecasted sales by 2% to account for EWR goals, but he explained that EWR plan savings are not uniform across rate classes, and the goals are 1.5% and 2.2% for

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[1348] 7 Tr 2643.
[1349] 7 Tr 2645-2646; See also Exhibit AG-1.37, page 5.
[1350] 7 Tr 2648.
[1351] 7 Tr 2648.

residential and C&I rate classes, respectively.[1352] Mr. Leuker also recommended changing Staff's COVID-related adjustment to utilize a use-per-customer trend rather than being based upon a total sales trend.[1353] Mr. Leuker testified that if Staff's model was adjusted based upon his recommendations, then it would result in a forecast that was 183 GWh lower than Staff's original forecast, which resulted in a forecast that only differed from the company's original forecast by -0.37%.[1354] Mr. Leuker recommended that the Commission adopt the company's original forecast given that Staff's forecast—after being adjusted with Mr. Leuker's suggestions—yielded a result only negligibly lower than was originally forecast by the company.[1355]

In the briefing, the company reiterates the points made in Mr. Leuker's testimony and reasserts the reasonableness of its original sales forecast.[1356] Staff states that it reviewed the DTE's critique of its sales adjustment, finds it valid, and now supports using DTE's original sales forecast.[1357]

In her initial briefing, the Attorney General argues that if Mr. Leuker's premise about the trend of declining sales in 2021 compared to 2020 was correct, then the pattern of lower sales should be consistent. But instead, the Attorney General asserts that in four months of the ten-month period selected by Mr. Leuker (i.e. March 2021-December 2021) residential customers actually used more electricity than they did in 2020.[1358] The Attorney General also faults DTE's projection noting that Mr. Leuker

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[1352] 7 Tr 2652.
[1353] 7 Tr 2655.
[1354] 7 Tr 2655-2656.
[1355] 7 Tr 2656.
[1356] DTE brief, 175.
[1357] Staff brief, 155.
[1358] Attorney General brief, 20-21.

confirmed that he had never used mobility data in prior rate cases, and had never investigated whether Mr. Coppola's prior forecasts turned out to be more or less accurate than his own.[1359]

In reply briefing, DTE argues that the Attorney General's suggestion about what might be intuitive about electric use trends carries no weight in the face of contrary data.[1360] DTE also emphasizes that using mobility data to forecast sales was suggested by a leading load forecasting group, and the utility tested mobility data and found it to be statistically significant when forecasting load.[1361] Further, DTE rejects the Attorney General's suggestion that it should investigate the accuracy of Mr. Coppola's previous forecasts opining first that the Attorney General bears that burden, and second that since Mr. Leuker's forecasts were known to be accurate it was fair to assume that Mr. Coppola's previous forecasts to the contrary were inaccurate.[1362]

Staff provides no reply briefing on this issue, and the Attorney General's reply brief largely recaps the arguments raised in her initial brief.[1363]

This PFD agrees with Staff and recommends adopting DTE's sales forecast. This PFD acknowledges the Attorney General's challenges to the utility's forecast but ultimately concludes that the DTE's rebuttal testimony sufficiently addressed the issues raised to validate the adequacy of company's forecast.

[1359] Attorney General Brief, 21.
[1360] DTE reply, 133.
[1361] DTE reply, 134.
[1362] DTE reply, 135.
[1363] AG reply, 29-30.

2. RIA credit count

DTE projected Residential Income Assistance (RIA) credits of 61,745 for the projected test year. Ms. T.Johnson testified to the company's projection.

Ms. Brauschweig explained that Staff discovered a discrepancy in DTE's data reporting of customer counts for the RIA credit. 8 Tr 5287. Citing Exhibit S-9.2, she testified that DTE combined its RIA and Low Income Assistance (LIA) credit counts into a single number. She reproduced the split provided for 2016 to 2018 in that discovery response, and further testified:

> The discrepancies between Company witness Johnson's testimony and what is reported in the filing requirements and by Company witness Maheen Asghar in Exhibit No. S-9.2 make it difficult for Staff to discern actual customers receiving each credit. Staff proposes in future cases, the Commission require the Company ensure their data aligns with testimony and requests.[1364]

Ms. Braunschweig also explained that DTE has a history of overprojecting RIA credit counts in rate cases. Based on her review of the combined RIA/LIA customer counts, she concluded that they continue to trend downward.[1365] She explained Staff's recommended credit count, and also recommended that the Commission further caution DTE:

> Staff proposes to round up to a total monthly enrollment of 65,000 for RIA and LIA—as supported by the Company's most recently reported enrollments. Staff proposes to retain the LIA enrollment of 32,000 and therefore proposes a projection of 33,000 for RIA enrollments. Moreover, if RIA enrollments for the test year exceed Staff's projection, Staff expects DTE to continue enrolling all eligible customers in the RIA credit and choosing customers from the RIA credit to receive the LIA until the Company reaches the approved cap on LIA enrollment. The RIA credit is not "funded" at a certain level but utilizes a projection of the customers

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[1364] 8 Tr 5274.
[1365] 8 Tr 5276.

> expected to receive it in the test year for ratemaking purposes. The credit's availability is not contingent on anything but customers meeting the requirements, and the Company should be reminded of that by the Commission once again.[1366]

Mr. Willis, who used the RIA counts in Ms. T. Johnson's testimony in his rate design, testified in rebuttal that there is no discrepancy between the company's credit count reporting and rate case projections on the one hand and the actual RIA counts on the other hand:

> Witness Johnson is characterizing current enrollment as of June 2021. The audit response and Part III filing reflect historic multi-year average figures. The Company's rate design forecast reflects what the Company estimates enrollments will be during the projected test period based on historic actuals and known and measurable changes, consistent with how billing determinants in the case are generally designed. While the three numbers are different, they represent three different time periods and approaches – they are neither inconsistent nor in conflict.[1367]

Mr. Willis presented his own chart to show monthly RIA credits from 2018 to March 2022, asserting that there has been an increasing trend over that period, with a "dip" in 2018 caused by "IT system issues."[1368]

In its brief, Staff contends that its projection and resulting revenue increase of $2.6 million should be adopted. It disputes Mr. Willis's rebuttal presentation, arguing that DTE has not established that it is using correct data, given that the 2020 RIA count was approximately 32,688 as shown at 8 Tr 5276.[1369] In its brief, DTE relies on Mr. Willis's and Ms. T. Johnson's testimony, and characterizes its projected test year RIA enrollment of 61,745 as reasonable. It characterizes Ms. Braunschweig's testimony as

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[1366] 8 Tr 5276.
[1367] 6 Tr 975.
[1368] 6 Tr 976.
[1369] Staff brief, 157-158.

"propos[ing] to limit the RIA enrollment forecast to 33,000, and move any RIA overflow onto LIA until the 32,000 LIA cap is reached."[1370]

Staff's reply brief addresses that characterization, arguing:

> Staff is not attempting to limit RIA enrollment or perform it in the way DTE misinterpreted Staff's proposal. Staff specifically stated in its direct testimony: "Staff expects DTE to continue enrolling all eligible customers in the RIA credit and choosing customers from the RIA credit to receive the LIA until the Company reaches the approved cap on LIA enrollment." (Braunschweig 8 TR 5276, Line 11-14.) The Company is misunderstanding how enrollment should be performed by stating in brief that Staff proposed limiting RIA enrollment to 33,000 and any remaining eligible customers would be placed on the LIA until the 32,000 cap is reached. Instead, as Staff stated in testimony, all eligible customers should receive the RIA and 32,000 monthly RIA recipients should be chosen to receive the LIA.[1371]

This PFD finds Staff's projection and adjustment should be adopted. DTE did not explain why it changed its data reporting for 2016-2018 from its last rate case to this case, as shown in Exhibit S-9.2. Not only did it file combined LIA and RIA enrollment data, but it did so as a three-year average, producing wildly different numbers than presented in Case No. U-20561.

Ms. T. Johnson testified to "current RIA enrollment" of 64,000 customers, but did not pinpoint the date of the measurement. Given the 2020 combined enrollment of 64,688, Staff reasonably concluded that Ms. T. Johnson's number is also a combined enrollment figure. DTE provided no explanation for what would be a sudden near-doubling of RIA enrollment levels from 2020 to 2021.[1372] This PDF notes that DTE did

[1370] DTE brief, 252.
[1371] Staff reply, 17.
[1372] The record does not answer the question whether DTE is limiting LIA enrollment for some reason, for example to take advantage of the deferred accounting available for enrollments over the 43,000 enrollment level provided in the Commission's May 8, 2020 order in Case No. U-20561, pages 179-181,

not ask to have the cap revised on its accounting deferral, which would be surprising if its RIA enrollments on a non-consolidated basis were really already above that 60,000 cap.[1373] Instead, Ms. Uzenski's proposed accounting focused on a combined RIA and LIA tracking and deferral, with a rollover of overcollected amounts to subsequent year credits.[1374]

Turning specifically to Mr. Willis's graph, this PFD notes that he did not provide the specific monthly values, the monthly data points on the graph are for a more limited period of time—approximately three years—relative to the annual data Ms. Braunschweig presented at 8 Tr 5276 over the period 2016 through 2020. Mr. Willis did not present comparable annual data for 2021, and did not present a breakdown of LIA and RIA data to overcome the company's unexplained decision to combine and average those counts in its filing. While Staff identified a 2020 value of 32,688 RIA enrollments, it appears that many if not all of the monthly values Mr. Willis used in his graph are above that value, although as noted above Mr. Willis did not provide the actual data points. Because his monthly data is not smoothed, and for only a three-year period, it is not possible to discern a trend, especially because by his own admission, the 2018 data reflects an IT system issue, with zero enrollments shown for one month. Staff's more careful consideration of the historical data inspires more confidence in its projection, and this PFD finds that it is supported by a preponderance of the evidence and should be adopted.

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or to reserve LIA spaces for some reason. This PFD notes only that a significant change should call for explanation.

[1373] See May 8, 2020 order, Case No. U-20561, pages 179-181, establishing a cap of 60,000 based on DTE's enrollment figures in that case.

[1374] 7 Tr 2769.

Staff and DTE appear to have agreed on a modification to the current deferred accounting mechanism for RIA and LIA credits the Commission put in place in Case No. U-20561. Although DTE initially requested to be able to simply roll overcollections in one year to offset assistance in the following year,[1375] after Staff objected,[1376] DTE proposed that deferred assets and liabilities be retained, but in lieu of biennial reconciliations, the net balance be addressed in rate cases.[1377] Staff is wary of DTE overprojections, but did not expressly object to this approach, as explained in Staff's brief:

> Staff does not disagree with the Company's directive to avoid reconciliations every two years and does not take issue with future regulatory asset/liability balances being addressed in future rate cases. The Commission should, however, be cautious of the goal behind the Company's proposals relating to the RIA and LIA projections, since the Company continues to project higher RIA enrollments year over year while actual enrollments decrease, which would make it so there are no additional customers to apply a year's overage to in the next year. (Braunschweig, 8 TR 5276, Line 1-3.) Staff's proposed regulatory liability will continue the Commission's work in the last DTE electric case to financially protect the Company and ratepayers from any difference in projected customer counts. (Braunschweig, 8 TR 5277, Line 10-17.)[1378]

On this basis, this PFD recommends that the Commission permit the deferred accounting balances to be presented and rate treatment determined in rate cases rather than through a biennial reconciliation.

[1375] Johnson, 5 Tr 816.
[1376] Braunschweig, 8 Tr 5277-5278.
[1377] DTE brief, 252-253.
[1378] Staff brief, 226.

E. Fuel and Purchased Power Expense

Staff's fuel and purchased power expense projection initially differed from DTE due to a difference in sales forecasts. Staff and DTE now agree on the sales forecast and fuel and purchased power expense.

F. Operations and Maintenance Expense

1. Inflation

DTE used composite inflation rates of 3.1% for 2021, 2.9% for 2022, and 2.42% for 2023, based on a composite of its internal 3% projected increase in labor costs and the forecast Consumer Price Index changes for the CPI-Urban, non-labor index. While ordinarily a source of dispute, there is little difference between DTE's projections and the CPI rates typically relied on by Staff and intervenors. Only ABATE raised a specific objection to the company's use of inflation. Ms. York testified:

> There are many moving pieces with respect to the Company's labor expense. This includes changes in the number of new employees, which would potentially be brought on at lower wages than the average wage of existing employees, and recognizing that certain employees may retire over time and be replaced by new, less experienced, employees at lower wages. Finally, DTE's wage escalation assumption does not consider that certain escalations may be managed such that the expense may not increase at the overall cost of inflation. This could include certain employee wage changes. Mr. Cooper neglects to consider how these variables might impact the actual wage escalation, and instead relies on a limited amount of historical wage changes.[1379]

She recommended an independent economic forecast of labor costs, which she considered embodied in the CPI projections DTE used. She acknowledged inflation estimates have increased since then, but noted DTE's discovery response in Exhibit

[1379] 8 Tr 3012.

AB-10, pages 1-2, to show that DTE has been able to offset inflation in prior years, but has not included any specifically identifiable offsets in this case.[1380] She further testified:

> The Company also indicated that it is using 20 its process improvement methodologies to hold costs below the inflation rate, but then claims that cost increases above the average inflation rate for base materials and qualified contract labor are expected to put pressure on its efforts.[1381]

She also presented Table 2 at 8 Tr 3017 to compare DTE's O&M expense levels to the CPI from 2011 to 2020.

Mr. Cooper addressed Ms. York's testimony in rebuttal, contending that she ignored the impact on DTE's costs of promotions and pay raises:

> Witness York's assertions largely ignores the impact of pay progressions as provided under the Company's Collective Bargaining Agreements for represented employees and advancements in pay scale and promotions for the Company's non-represented employees. Indeed, 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%.[1382]

As noted above, Ms. Crozier also testified that DTE has not been fully able to offset inflation in recent years.[1383]

ABATE argues that the Commission has rejected DTE's composite labor and CPI inflation rate.[1384] ABATE further argues that DTE's O&M expenses decreased by 0.73% from 2011 to 2020.[1385] In its brief, DTE relies on Mr. Cooper's testimony.[1386]

The Commission has rejected composite inflation rates in prior cases, and the parties who are not objecting to the inflation rates DTE is using in this case are not

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[1380] 8 Tr 3015.
[1381] 8 Tr 3015-3016.
[1382] 7 Tr 1885.
[1383] 7 Tr 2389-2390.
[1384] ABATE brief, 52-53.
[1385] ABATE brief, 54.
[1386] DTE brief, 178.

waiving their objections to the composite approach. While ABATE similarly may rely on prior Commission decisions, it has not justified its contemporaneous objection to more current inflation projections. Recognizing, as discussed in section VI above that there is some uncertainty regarding future inflation, this PFD finds it acceptable under the circumstances to utilize DTE's inflation rates as a general matter. There are exceptions, however, to follow the Commission's prior determinations regarding expenses such as health care that are influenced by a multitude of factors. Additionally, since the company's approach to combating inflationary pressure may lead to overcapitalization of costs that should be expensed, this PFD calls for an evaluation of the company's capitalization policies, which will hopefully place future projections on a more solid footing.

2. Generation Expense (Exhibit A-13, Schedule C5.1)

Mr. Morren presented direct testimony in support of DTE's projected test year steam power generation O&M expense of $223.8 million. Ms. Kindschy explained that DTE adjusted its projected O&M expense for the retirements of River Rouge, St. Clair and Trenton Channel, subtracting 2020 O&M expense for those plants after it had adjusted the 2020 O&M expense base for inflation.[1387] As shown in Exhibit S-22, Ms. Kindschy calculated a reduction of $4,581,000 to remove the inflation associated with 2020-level expenditures. In its brief, Staff states that DTE did not rebut Ms. Kindschy's recommendation and argues the Commission should adopt this adjustment.[1388]

[1387] 8 Tr 5480, Exhibit S-21, page 2.
[1388] Staff brief, 162-163.

In its brief, DTE asserts that the Commission should adopt its projected O&M expenses, citing Mr. Morren's testimony at 5 Tr 717-724, but does not specifically address Staff's adjustment. DTE's reply brief similarly does not address this issue.[1389]

This PFD concludes Staff's adjustment should be adopted.

3. Distribution Expense (Exhibit A-13, Schedule C5.6)

a. Restoration O&M

Ms. Pfeuffer testified in support of DTE's projected restoration O&M expense, using a three-year average as DTE used for its capital expense projection.

Staff recommended an increase in the distribution O&M expense of $14.78 million to reflect use of a five-year rather than a three-year average to project storm restoration expense, as Mr. Becker explained.[1390] In rebuttal, Ms. Pfeuffer reiterated DTE's view that a three-year average should be used, as discussed above, although DTE agrees that if the Commission uses a five-year average for emergent capital, it should also use a five-year average for restoration O&M.[1391]

In its brief, Staff argues that it is being consistent for expenses that are either capitalized or O&M depending on whether a retirement unit is replaced.[1392] DTE relies on Ms. Pfeuffer's testimony on this issue.[1393] For the reasons explained above, this PFD concludes that the five-year average should be used.

[1389] See DTE reply, 138.
[1390] 8 Tr 5418.
[1391] 4 Tr 505.
[1392] Staff brief, 163-165.
[1393] DTE brief, 182; DTE reply, 140.

b. Tree trimming

Ms. Hartwick testified in support of DTE's proposed tree-trimming expenditures, and to account for the Enhanced Tree Trimming Program or "surge" funding. She testified that DTE Electric spent $151.1 million on the tree trimming program in 2020, $16.5 million more than the level approved in Cases Nos. U-20561 and U-20162.[1394] She discussed the difficulties of measuring tree-trimming work and presented data in terms of miles and "comparable units." She testified that DTE met its targets for 2020, but is not going to meet its targets for 2021, presenting comparisons of current projections to previous plans, and citing unprecedented summer storms and unfavorable fall weather as the primary reasons.[1395] She also explained that in focusing on the areas hardest hit by the storms, DTE needed to tackle more dense vegetation.

Regarding the ETTP program, she presented DTE's March 1, 2021 report as Schedule V1 of Exhibit A-31. She also presented data showing miles completed to the ETTP standards in Detroit and in its service area generally, as well as outage results following the trimming in contrast to circuits not trimmed to these standards.[1396] She explained that DTE is committed to a five-year tree-trimming cycle, and presented data to show what that encompasses, and to show that it compares to the industry average of 4.9 years. She discussed the surge program, citing a net present value analysis performed by Mr. Vangilder in Exhibit A-22, showing a $71.2 million value to the program. She also discussed the spot trimming included in the surge program:

> Reactive trouble activities in support of outages and wire downs are included 8 in the Surge funding. This includes reactive spot trimming

[1394] 7 Tr 2282.
[1395] 7 Tr 2289.
[1396] 7 Tr 2291-2294.

> which has increased 9 significantly to address circuits with high volumes of customer reliability issues.[1397]

To meet its five-year cycle goals and complete the surge program in 2024, Ms. Hartwick testified that DTE is requesting base O&M for tree trimming of $103.9 million and surge funding of $67.0 million in 2023 and $52.7 million for 2024, holding out the possibility that additional surge funding will be needed in 2025.[1398] Ms. Hartwick explained that DTE intends to recover the deferred surge program costs through securitization and deferred to Mr. Lepczyk's testimony regarding the company's request to increase the return on the deferred costs in the interim.[1399]

No party disputed DTE's projected tree trimming expense or its surge program spending plan. The only issue related to the surge program concerns the dispute between DTE on the one hand and Staff and the Attorney General on the other, regarding the interest rate to use for the accumulated regulatory asset under the surge program. That dispute is discussed below in subsection D.3.

The Attorney General raised an issue regarding savings from the tree trimming surge program. Mr. Coppola testified cited Table 11 in Ms. Hartwick's testimony, 7 Tr 2312, which estimated annual cost savings for both capital and O&M due to the surge program. Ms. Coppola also cited DTE's discovery response in Exhibit AG-1.42, which provides a cost estimate of $5.7 million in restoration expense savings in the test year relative to 2020 due to the surge program. Mr. Coppola testified that the $5.7 million in savings should be reflected in the distribution system O&M costs.[1400] In her rebuttal

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[1397] 7 Tr 2314.
[1398] 7 Tr 2319.
[1399] 7 Tr 2322-2323.
[1400] 8 Tr 4857-4858.

testimony, Ms. Hartwick agreed that the savings should be reflected, but further testified that a portion of the savings, $1.5 million, is already included in the total surge cost projection, citing Exhibit A-22, line 4. She testified that the remaining savings, $4.2 million, were inadvertently omitted from Schedule C5.6.[1401]

In its brief, DTE included an additional $4.2 million reduction to its surge-related O&M savings estimate consistent with Ms. Hartwick's testimony. The Attorney General argues that the entire $5.7 million should be reflected. The Attorney General acknowledges Ms. Hartwick's reference to Exhibit A-22, but argues this exhibit is an informational exhibit that cannot be tied to the expense projections in Exhibit A-13, Schedule C5.[1402] This PFD concludes after reviewing Exhibit A-22 that it is reasonable to accept Ms. Hartwick's testimony. The $67 million surge funding level for 2023 on lines 6 and 12 of Exhibit A-22, page 1, which ties to the 2023 surge funding level in Schedule C5.6.1 of Exhibit A-13 appears to be derived at least in part from the reduced reactive cost projection on line 4. This PFD concludes that DTE's credit of the additional $4.2 million is sufficient.

MNSC also argues that DTE should consider a variable-length tree trimming cycle. DTE objects to this proposal,[1403] and it is discussed below regarding future cases.

c. Community Lighting

Mr. Bellini also testified in support of DTE's projected O&M expense for its community lighting program. Dr. Wang on behalf of Staff and Mr. Bunch on behalf of MI MAUI recommended adjustments as discussed in subsections i) and ii) below.

[1401] 7 Tr 2334.
[1402] Attorney General reply, 32.
[1403] See DTE reply at 141.

i. Staff adjustments

Consistent with the discussion of DTE's capital expense projections, Dr. Wang reviewed 2021 actual expenditures in comparison to DTE's forecast, and recommended a reduction to the O&M expense projection as well. Staff's recommended reduction of $242,000 is shown in Exhibit S-7.3.[1404] In rebuttal, Mr. Bellini objected to the reduction, stating that DTE's test year projection was based on 2020 O&M adjusted only for inflation, and also stating that DTE's 2021 O&M expenses were higher than its test year projection.[1405]

In its brief, Staff urges the Commission to adopt its recommendation.[1406] Staff addresses Mr. Bellini's rebuttal testimony by arguing that if the company is not expected to spend the full amount of its bridge and test year capital projection, "it is also reasonable to assume the associated O&M spending will also be reduced."[1407] MI MAUI and Ann Arbor endorse Staff's recommendation in its brief.[1408] DTE relied on Mr. Bellini's testimony in its initial brief, and in its reply brief, contends that Staff has no basis for contending that a reduction in capital spending would have a corresponding reduction in O&M spending, arguing "[t]hey are two different things."[1409] It contends: "Staff's assumptions are also entirely speculative and unsupported, and therefore cannot support a decision."[1410]

[1404] 8 Tr 5173.
[1405] 7 Tr 1775-1776.
[1406] Staff brief, 165-167.
[1407] Staff brief, 166.
[1408] MI MAUI brief, 60.
[1409] DTE reply 142.
[1410] DTE reply, 142, also citing *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-497, 500-501, 507 (1994), and *In re Complaint of Pelland*, 254 Mich App 675, 685-86 (2003).

In its brief, DTE relies on Mr. Bellini's testimony. Staff argues that the Commission should adopt Staff's recommendations. This PFD finds Staff's recommendation reasonable and concludes it should be adopted. Since DTE was projecting it would spend both capital and O&M, it is appropriate to reduce the O&M expense allowance along with the capital expense projection.

ii. LED lamp washing

MI MAUI and Ann Arbor argue that DTE's proposed spending of $270,322 on LED street lamp washing in the test year is excessively high, due to DTE washing the street lamps too frequently.[1411] MI MAUI and Ann Arbor argue that while DTE cites its own research to justify that washing LED's every five years is necessary, a peer-reviewed Illumination Engineering Society (IES) study concluded that almost all LED models do not need to be washed until at least ten years after they are installed.[1412] MI MAUI and Ann Arbor further argue that if the LEDs purchased by DTE requires more frequent cleaning than almost all LED models, then DTE should not have purchased that model and customers should not bear the costs of such an imprudent choice.[1413] Mr. Bunch explained the IES study results and recommended that the Commission reduce cost recovery for the LED washing program by 50%, to $135,000 per year, under the theory that the LEDs are being washed twice as often as they need to be.[1414]

In support of DTE's current lamp washing policy, Mr. Bellini testified that the IES study did not include the LED type predominately used by DTE and that this study was not specific to the environment in which the LED's utilized by DTE are intended to

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[1411] MI MAUI brief, 66.
[1412] MI MAUI brief, 66; Exhibit MAUI-22.
[1413] MI MAUI brief, 66.
[1414] 8 Tr 3473-3474.

operate.[1415] Mr. Bellini testified that DTE studied the impact of Michigan's heavy truck traffic as well as roadway conditions on the LED lamps, and found that washing on a five year cycle kept the LEDs clean enough to properly light the roadways.[1416] Mr. Bellini reiterated that an LED located in Phoenix, Arizona will be impacted differently than an LED in the Detroit-metro area.[1417]

In their reply brief, MI MAUI and Ann Arbor utilize the comparison offered by DTE, and cites Federal Highway and Safety Administration statistics and U.S. Census data to show that, based upon population and highway data, there is likely more heavy truck traffic in Phoenix than Detroit.[1418] Next, they argue that DTE may not rely on its internal study supporting the company's contention that it must wash its LED lights more frequently, as it failed to produce that study in discovery, except for slides that DTE utilized when presenting this information at a conference.[1419] MI MAUI and Ann Arbor further this point by comparing the peer-reviewed IES study it has offered, which examined the data from a variety of cities (including Minneapolis) to the internal study of DTE's that has not been peer-reviewed or reviewed by MI MAUI and Ann Arbor for its accuracy.[1420]

In its reply brief, DTE contends that MI MAUI and Ann Arbor misconstrue Mr. Bellini's testimony regarding lamp washing. DTE seems to dispute that Mr. Bellini contended that the type of luminaire the company uses is of significance, arguing that MI MAUI and Ann Arbor "misconstrue[] this [testimony] as simply suggesting that the

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[1415] 7 Tr 1762-1763.
[1416] 7 Tr 1763.
[1417] 7 Tr 1763.
[1418] MI MAUI reply,11-12.
[1419] MI MAUI reply,12.
[1420] MI MAUI reply, 13-14.

company uses a model of LED luminaire that needs more frequent cleaning," then contending that they are "ignoring Mr. Bellini's explanation that heavy truck traffic and salt spray are unique to a Midwest state such as Michigan, and particularly to the Company's service territory." [1421]

This PFD finds MI MAUI and Ann Arbor's argument persuasive that DTE failed to produce its own study when requested, as shown by Exhibit MAUI-19, and thus has failed to establish that its LED washing program is reasonable and prudent. This PFD recommends that the Commission reduce cost recovery for the LED washing program by 50%, to $135,000 per year. This PFD notes that the slides DTE presented did not reach a specific conclusion regarding cleaning frequency, but concluded only that a cleaning program should be considered, as shown in Exhibit MAUI-44. DTE's effort to shield its study as "confidential" is unwarranted. DTE does not dispute Mr. Bunch's characterization of the national study results, and since that study included a variety of lamp types and locations, including Minnesota, DTE did not establish that its conclusions should readily be dismissed in the absence of an alternative. This PFD further notes DTE's testimony that its LED lights are on taller poles than some other utilities use, which would further shield them from road dirt.

d. Customer service normalizing adjustment

Mr. Coppola objected to a normalizing adjustment to the 2020 O&M expense levels for distribution operations. He noted that $1.2 million was added to the 2020 O&M expense level to reflect remove the effects of a temporary transfer of 35 employees from distribution operations to customer service operations. Mr. Coppola testified that

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[1421] DTE reply,144.

no offsetting normalizing adjustment was made to the Customer Service 2020 O&M expenses. He concluded that the adjustment was not appropriate and should be removed.[1422] DTE did not address this in rebuttal or in its brief, and this PFD concludes that the adjustment should be adopted.

4. Customer Service (Exhibit A-13, Schedule C5.7)

On behalf of DTE, Mr. Sparks testified that the company spent $110.7 million on customer service O&M expense in the historical test year and forecasted $133.6 million in customer service O&M expense in the projected test year.[1423] He also described the function of the customer service division and the allocation of expenses between DTE Electric and DTE Gas.[1424] Subsection a. addresses certain adjustments DTE made to its 2020 expense levels that serve as the base for its inflationary projections for the test year, and to projected test year expense levels above that inflationary projection. Subsection b. addresses DTE's merchant fee expense projection.

a. Customer Service Representatives

Consistent with a footnote on Schedule C5.7 of Exhibit A-13, Mr. Sparks testified that historical test year expenses were increased by $1.8 million "for One-Time savings from delayed hiring."[1425] He also specified that an additional $7.9 million adjustment was needed in the test year for a 120 headcount increase in customer service representatives (CSRs) and to address more complex customer calls.[1426] He stated that while DTE had more web-based avenues for customers to resolve issues, the company

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[1422] 8 Tr 4856-4857.
[1423] 7 Tr 1616; see also Exhibit A-13, Schedule C5.7.
[1424] 7 Tr 1617-1624.
[1425] 7 Tr 1625.
[1426] 7 Tr 1637.

required more CSRs to improve the average speed to answer customer calls.[1427] Mr. Sparks stated that DTE's current target is to be able to answer 60% of customer calls within 90 seconds,[1428] but testified that DTE will focus on "80% of inbound calls answered in 30 seconds," which "will exceed customer expectations and is considered best in class by JD Power."[1429] He also attributed $2.3 million of this amount to full implementation of time-of-use rates, referencing "resource requirement so to handle an incremental 430K additional calls to the Contact Center and an additional 250K of billing exceptions."[1430] He further subdivided the $2.3 million to $1.3 million for "billing exceptions," $0.5 million for "digital experience," and $0.5 million for "AMI support."[1431]

Mr. Coppola testified that there was little if any delayed hiring of CSRs during the pandemic because information from DTE showed that the number of CSRs assigned to DTE Electric substantially increased from 2019 to 2022.[1432] He opined that the utility's request for 120 more CSRs was "troubling," explaining that DTE spent and continues to request millions for digital technology to allegedly automate functions and reduce the need for CSRs to handle calls.[1433] Mr. Coppola expressed that DTE "can't have it both ways" and protested that the company's request for an additional $9.7 million to hire more CSRs is counter to the capital spending proposed by Company Witness Pizzuti in areas intended to reduce the need for CSRs.[1434] Mr. Coppola recommended that the Commission remove $9.7 million allocated for more CSRs from the Company's

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[1427] 7 Tr 1637.
[1428] 7 Tr 1638.
[1429] 7 Tr 1635.
[1430] 7 Tr 1638.
[1431] 7 Tr 1638.
[1432] 8 Tr 4860.
[1433] 8 Tr 4860.
[1434] 8 Tr 4860.

proposed O&M expense and requested that DTE be directed to provide a cost/benefit analysis in its next rate case to examine the cost of capital expenditures to date and their effect on call handling and customer service.[1435]

In rebuttal, Mr. Sparks opined that the digital and IT enhancements sponsored by Witness Pizzuti are anticipated to decrease call volumes for customers with simple issues, but the calls that remain are complex and would require a knowledgeable CSR.[1436] He also testified that Mr. Coppola's request for a $9.7 million disallowance was overbroad specifying that only $5.6 million was allocated for 120 more CSRs while $1.8 million was "driven by lag hire in 2020 due to the pandemic" and $2.3 million was "associated with ongoing O&M for TOU implementation."[1437] He specified that the amounts associated with lag hiring and TOU implementation were unrelated to the company's request for additional CSRs.[1438] Mr. Sparks addressed the claim that there was no delay in hiring during the pandemic stating that "[w]ithout additional context, Witness Coppola's assumption would appear reasonable; however, the change in headcount was actually driven by incremental CSRs hired for a new call center in Cass City during 2020 rather than an actual headcount increase for non-CSRs."[1439] He added that while he did not support Mr. Coppola's proposed recommendation, the company could support a $0.95 million reduction to account for call volume reduction savings; he based this estimate on "a reduction in calls from 2020 historical of 4.15 million to a 3.9 million estimate for 2023," and "the existing vendor Cost Per Call of $5.85," with a

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[1435] 8 Tr 4861.
[1436] 7 Tr 1642.
[1437] 7 Tr 1642-1643; see also Exhibit A-13, Schedule C5.7.
[1438] 7 Tr 1643.
[1439] 7 Tr 1643.

portion of the savings allocated to DTE Gas."[1440] Mr. Sparks also explained that DTE did hire 231 additional CSRs in 2020, but "no additional dollars [were] requested in this case as the Company will see an offset in outside services spend associated with this change."[1441] He testified that the cost of the additional CSRs was "offset by a $3 million decrease in external call vendor spend."[1442]

In its initial brief, DTE summarizes the points made by Mr. Sparks.[1443] In her initial brief, the Attorney General argues that the adjustment recommended by Mr. Coppola should be adopted. She addresses Mr. Sparks' rebuttal testimony by questioning that the need for the additional CSRs is explained by increased call complexity, suggesting that better training could address call complexity.[1444] Regarding the TOU program, the Attorney General cites discovery in Exhibit AG-1.61 to show that DTE has indicated plans to hire external vendors.[1445] The Attorney General also argues that the number of customer service complaints received by the Commission has declined significantly since 2019, and that company's customer service metrics have always been somewhat erratic, so there "is no compelling evidence to justify the additional headcount increase DTE seeks."[1446]

In its reply brief, DTE argues that the Attorney General "misconstrues her own discovery request" with relation to the TOU program, which per DTE, asked the company to confirm whether the TOU program and lag hiring require the addition of

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[1440] 7 Tr 1644, 1647.
[1441] 7 Tr 1643.
[1442] 7 Tr 1643.
[1443] DTE brief, 194.
[1444] AG brief, 26.
[1445] AG brief, 26.
[1446] Attorney General brief, 27.

CSRs.[1447] DTE also emphasizes that CSR staffing needs are driven by call volume and average handle time (AHT) per call.[1448] DTE elaborates that it takes more time to explain specialized COVID-related payment plans and to properly pre-screen and advise customers with high bills and low income about requirements for agency resources.[1449] DTE asserts that the Attorney General disregards the utility's evidence and recommends rejecting her recommended disallowance specifying that the company still agrees to a $0.95 million reduction in overall O&M to capture call volume savings.[1450]

In her reply, the Attorney General describes DTE's contention that more CSRs are needed to address low-income customers with high bills as a "another self-fulfilling irony in DTE's case."[1451] She explains that by its own reasoning, DTE would need fewer CSRs if it found ways to make its service more affordable and dispensed with annual rate increase requests seeking hundreds of millions of dollars.[1452] The Attorney General maintains her recommendation that the Commission remove $9.7 million from the Company's O&M expense. Staff supports the Attorney General's recommended adjustment.[1453]

This PFD finds that DTE has failed to justify its projected increase in the O&M expense allowance for the Customer Service group above an inflation-adjusted 2020 level that excludes DTE's "hiring lag" adjustment. DTE made no effort in its direct case

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[1447] DTE reply, 145; see also AG 1.61 page 1 of 7.
[1448] DTE reply, 145.
[1449] DTE reply, 146.
[1450] DTE reply, 146.
[1451] Attorney General reply, 33.
[1452] Attorney General reply, 33.
[1453] Staff reply, 17-18.

to compare the level of effort embedded in its 2020 expenditures to the level of effort it is striving for with the additional expenditures. For example, it did not identify its current level of CSRs, or provide measures of their workload. DTE did not present an evaluation of its associated with its projected call volumes or call handling time requirements in light of all of its IT and other capital investments in digital technologies and digital customer service. Even in his rebuttal testimony, which is not the time for such information to be presented, Mr. Sparks did not explain the basis of his estimated reduction in calls or how this relates to the claimed additional staffing needs. While Mr. Sparks presented lofty goals of reduced customer wait times and increased customer satisfaction to meet "best in class" criteria, he did not establish the level of expenditure necessary to achieve these goals, or justify the goals relative to other potential spending priorities, given the high levels he reported at 7 Tr 1634-1635 and no additional information regarding any shortcomings in service quality. While expeditious customer service is desirable, DTE's target to answer most customer calls within a certain timeframe, standing alone, does not necessarily justify an increase of several million dollars to meet a somewhat arbitrary customer service goal. This PFD further notes that its recommendation on this issue is consistent with the Commission's decision in a recent DTE Gas rate case in which that company proposed a similar increase seeking additional CSRs using substantially similar arguments.[1454]

This PFD also finds that DTE has been selective in the adjustments it has chosen to make to the 2020 test year. Mr. Sparks only disclosed in rebuttal that DTE

[1454] See December 9, 2021 order in Case No. U-20940, pages 128-129.

has in 2020 hired an additional 233 CSRs, also contending this expansion was "offset" by reduced vendor spending of $3 million, which was also only disclosed in rebuttal. This additional, undisclosed hiring calls into question whether DTE will actually hire the additional CSRs as it currently claims, and what the additional cost should be. As to that last point, if $3 million "offsets" the hiring of an additional 233 CSRs, what I the basis for DTE's projection of $5.6 million for an additional 120 CSRs. DTE has the obligation to support its expense projections and it has failed to do so. Because DTE has not justified the reasonableness of its overall level of customer service expenditures, it has not justified the addition of the 120 CSRs or the portion of the additional $9.7 million it ascribes to a "hiring lag" or to TOU costs. Clearly, DTE's ability to hire 233 CSRs in 2020 casts doubt on its claims that the $1.8 million in 2020 cost savings was merely "one-time" and should not be projected to last into the test year. This PFD has elsewhere addressed DTE's projected TOU expenses, but for purposes of the company's expense presentation here, finds that DTE did not establish the basis for its projected additional test year expense of $2.3 million.

b. Merchant fees

Mr. Burns testified in support of the utility recovering merchant transaction fees in rates in compliance with previous Commission orders. He explained that these merchant fees were borne by DTE when a customer paid with a credit or debit card.[1455] Mr. Burns asserted that the Company limited the types of cards it allowed for payments and restricted the use of card payments for certain C&I customers to minimize merchant

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[1455] 7 Tr 2494.

fee expenses.[1456] Per Mr. Burns, DTE projected $20.5 million in merchant fee O&M expenses in the test year.[1457]

Testifying for Staff, Ms. McMillian-Sepkoski explained that DTE's request was a 54% increase over the three-year average of $13.3 million.[1458] She explained that Staff proposed a disallowance of just over $2.9 million for the projected test period based upon a lower average increase in credit and debit card usage and a slightly more conservative projection for expenses in the test year.[1459] Ms. McMillian-Sepkoski testified that $17,549,164 was the appropriate amount to include in rates.[1460]

Mr. Coppola testified that residential merchant fees only increased by five percent between 2020 and 2021, and his projection of merchant fees for the test year was only $10.9 million.[1461] He explained that he arrived at that projection using residential customer payment information from 2016 through 2021 and by forecasting that 44.44% of the utility's customers would pay with debit or credit cards.[1462] Mr. Coppola recommended removing $8.2 million from the utility's projected O&M expenses opining that DTE's forecast improperly assumed that the average rate of increase in fees from 2018-2020 would continue unabated.[1463]

In rebuttal, Mr. Burns testified that Mr. Coppola incorrectly assumed that the growth in DTE's merchant fee forecast is directly related to the number of customers

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[1456] 7 Tr 2494-2495.
[1457] 7 Tr 2495; see also Exhibit A-13, Schedule C.5.7.1, page 1, line 5, column (g).
[1458] 8 Tr 5265.
[1459] 8 Tr 5265-5266.
[1460] 8 Tr 5266; also see Exhibit S-8.4.
[1461] 8 Tr 4865, 4866; also see Exhibit AG-1.45, page 1, line 12.
[1462] 8 Tr 4865
[1463] 8 Tr 4866.

paying with a card.[1464] Mr. Burns stated that the volume of payment transactions and the rate of fees per transaction are the primary driver of increased merchant fees.[1465] He also opined that Mr. Coppola's annual growth rate did not take into consideration anomalies, and DTE's multi-year growth rate would minimize anomalies from any specific year in predicting future sales.[1466]

In initial briefing, DTE reiterates its position but specifies that the utility does not oppose Staff's projected fee amount of $17.5 million, which it urges the Commission to adopt.[1467] In their initial briefs, Staff and the Attorney General reiterate the positions staked out in their testimony.[1468] In her reply brief, the Attorney General argues that DTE did not support its rebuttal argument because Mr. Burns did not provide any information about the transaction volumes or the rates charged by credit card companies.[1469] The Attorney General asserts that Mr. Coppola's projection was more reasonable because it took into account a saturation point at which growth in credit card transactions begins to slow.[1470] Staff provided no further reply to this issue, and DTE's reply brief recaps the positions stated in its initial brief.[1471]

This PFD agrees with Staff's position—which is now supported by DTE—and recommends a disallowance of $2.9 million which would set merchant fee O&M expenses at $17,549,164 for the test year. This moderated forecast of fee expenses

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[1464] 8 Tr 2527.
[1465] 8 Tr 2527.
[1466] 8 Tr 2528.
[1467] DTE brief, 196-197.
[1468] Staff brief, 173; Attorney General brief, 29.
[1469] Attorney General reply, 34.
[1470] Attorney General reply, 35.
[1471] DTE reply, 146-147.

represents a balanced approach when compared with the company's original forecast and the Attorney General's more conservative forecast.

5. Uncollectible Expense (Exhibit A-13, Schedule C5.8)

Ms. T. Johnson testified in support of the company's projected $59.6 million test year uncollectible expense projection as shown in Schedule C5.8 of Exhibit A-13. She explained how the company accounts for uncollectible expense, including a discussion of DTE's accounts receivable reserve and a discussion of its write-off procedures.[1472] She testified that DTE is excluding 2018 from its calculation of the three-year average of uncollectible expense:

> Uncollectible expense was abnormally high during 2018 due to system issues and delayed collections, resulting from the Customer 360 (C360) billing system implementation. This type of system upgrade occurs perhaps once in 10 to 15 years and had a significant impact on collection activities. The impact of those issues is not easily quantified. Therefore, the Company excluded 2018 uncollectible expense from the calculation.[1473]

Ms. T. Johnson acknowledged that in Case No. U-20162, the Commission adopted Staff's cash basis method of measuring annual uncollectible expense, but explained that DTE continues to object to that method:

> The cash basis method for estimating uncollectible expense is inconsistent with how expense is recorded and with how other costs and revenues are calculated for both MPSC reporting and ratemaking. The Company determines uncollectible accounts expense based on an accrual method as required by the Uniform System of Accounts (USofA); General Instruction number 11. Rates are set to cover the Company's expenses expected to be recorded for account purposes. The estimation of future expenses should therefore be consistent with the practice used to record the actual expenses to ensure recovery of the Company's prudent and reasonable costs. An average of the amounts charged to account 904

[1472] 5 Tr 820-822.
[1473] 5 Tr 822.

provides such consistency. In addition, the cash-basis method does not factor in special circumstances that are accounted for under the accrual method.[1474]

She provided the following examples to illustrate the point:

> For example, the write-off of some accounts is delayed because they are being disputed or negotiated and need to show as open in the billing system until a final decision is made. Another example is the 22 decision to temporarily suspend disconnects during 2020 due to the pandemic which drove a significant temporary decline in write-offs. The balances in these examples are expected to be charged-off, so under the Company's accrual method they are fully reserved. These situations would not be reflected in the cash basis method.[1475]

She also opined that the direct charges relating to the Company's forgiveness match to low-income customers should be included in uncollectible expense.[1476] She also explained factors that could influence the actual level of the company's test year uncollectible expense.[1477]

Mr. Rueckert and Mr. Coppola recommended alternatives. Mr. Rueckert testified on behalf of Staff, recommending a $9.56 million reduction to the company's projection.[1478] As shown in Exhibit S-18.1, he used the cash basis method approved by the Commission, with a three-year average for the years 2019 through 2021 of $51.83 million, which he further reduced to reflect projected reductions from capital investments totaling $1.82 million, resulting in a test year expense projection of $50.01 million. Mr. Rueckert explained his methodological choice:

> Staff uses and recommends the direct write-off method shown on exhibit S-18.1. The cash basis accounting of gross write-offs less recoveries to revenue is more accurate for uncollectible accounts expense projections

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[1474] 5 Tr 823
[1475] 5 Tr 823.
[1476] 5 Tr 823-824.
[1477] 5 Tr 824.
[1478] 8 Tr 5460, Exhibit S-18.

> for rate making purposes because it presents the actual write-offs and recoveries the Company receives from customers annually and includes direct expenses. Using the cash basis, direct write-off method, uncollectible accounts are written off directly to expense as they become uncollectible. This method is also used for U.S. income tax purposes.[1479]

Mr. Rueckert also cited Mr. Maroun's testimony endorsing this method for cost allocation purposes, and he used 2018 as an example of the benefits of this method:

> In Exhibit A-13, C5.8, historical year 2018's accrued uncollectible expense (Account 904) was excluded because it was reported abnormally high due to system issues and delayed collection, resulting from the billing system. In Staff's Commission approved cash basis, direct write-off, method calendar year 2018 is not unusually larger than previous years and shows the year should be include with the most current historical 15 information. See Exhibit S-18.1.[1480]

Regarding the savings figures Mr. Rueckert incorporated in his expense projection, he cited discovery responses from DTE regarding savings expected from two capital investments, the Business Rules Framework (BRF+) and an upgrade to the Revenue Management and Protection (RM&P) collection and theft field order scheduling and dispatching functions to its ClickSoft cloud-based solution.[1481]

Mr. Coppola testified that he used the Commission-approved method, and calculated a reduction of $9.4 million to the company's projection, using the three-year historical ratio of net charge offs to revenue for 2017, 2020, and 2021.[1482] Citing Exhibit AG-1.14, he explained that he omitted the years 2018 and 2019 due to the Company's suspension of collection activity for several months while it resolved data and systems

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[1479] 8 Tr 5461-5462.
[1480] 8 Tr 5462.
[1481] 8 Tr 5462-5463.
[1482] 8 Tr 4862-4864.

issues.[1483] He addressed Ms. T. Johnson's objection to the approved method by explaining:

> The booked expense for uncollectible accounts can fluctuate from year to year due to a number of reasons including assumptions made by the Company, temporary events, and the adequacy of the reserve account at the outset of any one particular year. Therefore, using booked uncollectible expense, as the Company has done in this case, is not wise or appropriate.[1484]

In addition to reiterating the company's preferred approach, Ms. T. Johnson testified to revisions to Staff's and Mr. Coppola's analysis. For Staff's analysis, she testified:

> There are 2 corrections that must be made to Staff witness Rueckert's 15 calculation if the cash basis method is used. The first correction is to the Electric Sales Revenue being used to calculate future uncollectable expense. Witness Rueckert used sales revenue of $4,993,828,000 (Exhibit S-3, Schedule C3, (ln. 3, col. F)) which excludes surcharges for Energy Waste Reduction, Nuclear Surcharge Revenue, LIEAF Surcharge Revenue and incremental revenue from rate relief. These surcharge revenues are included in the historical revenue Staff used to calculate write-offs as a % of revenue and the revenues associated with these surcharges should not be excluded as it would incorrectly understate the revenue associated with uncollectable expense. In addition, Staff's revenue calculation assumes present revenue when it should be based on proposed revenue including rate relief when calculating forward test year uncollectable expense as a % of revenue. The correct revenue number to use for the forward test period should be $5,356,676,000 (Staff Exhibit: S-6, Schedule F2, (ln 47, col C)) which is the equivalent to the revenue Staff used to calculate historical uncollectable expense as a percent of revenue. The second correction to the calculation is related to the reduction witness Rueckert included for savings driven by BRF+ of ($1.62 million). Staff rolled forward the 3-year historical to include 2021 uncollectable expense which the Company does not dispute, however, given the savings for BRF + are included in the historical 2021 actuals this method would double count the savings if also included as a reduction to the forward test year calculation. The above adjustments to witness Rueckert's schedule results

[1483] 8 Tr 4862.
[1484] 8 Tr 4862.

> in uncollectable expense of $55,398,915 vs. the original projection from witness Rueckert of $50,012,782.[1485]

In its brief, Staff agrees with Ms. T. Johnson's recalculation.[1486]

Regarding Mr. Coppola's analysis, Ms. T. Johnson objected to his use of 2017, 2020 and 2021 data in his average, testifying:

> The one material difference between witness Coppola and witness Rueckert's calculation was witness Rueckert's use of a 3-year historical average using 2019, 2020, 2021 vs. witness Coppola's use of 2017, 2020, 2021. Witness Coppola excluded 2019 write-offs due to the potential impacts included in 2019 driven by customer C360 implementation. Although 2019 write-offs were higher than normal it is important to note that 2021 write-offs were also historically low which is also bringing down the 3-year historical average. Given the significant amount of one-time stimulus and energy assistance our customers have received which have temporarily reduced write-offs, the Company believes it is appropriate to use a 2019 through 2021 3-year average to estimate projected uncollectable expense.[1487]

In her brief, the Attorney General notes that DTE's arguments regarding the methodology for projecting uncollectible expense have been consistently rejected in prior cases. She also cites DTE's discovery response in Exhibit AG-1.58 to "dispel[] any doubt that the approach used by the AG somehow does not conform to the accounting rules,"[1488] and to confirm that Mr. Coppola's removal of 2019 costs is legitimate.[1489] The Attorney General argues Mr. Coppola's recommendation should be adopted.

In its brief, DTE relies on Ms. T. Johnson's testimony in advocating for the alternative method. It acknowledges that the Commission adopted a cash-basis method in Case No. U-20162, but contends that this is inconsistent with how expense is

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1485 5 Tr 829-830.
1486 Staff brief, 173-174.
1487 5 Tr 831.
1488 Attorney General brief, 28.
1489 Attorney General brief, 29.

recorded and how other costs and revenues are calculated for ratemaking and MPSC reporting.[1490] In its reply, DTE argues: “The AG’s Initial Brief, pp 28-29 vaguely incorporates and maintains Mr. Coppola’s proposal, but does not add to the discussion. The company also again objects to the AG forcing others (including now the ALJ) to chase down discovery responses that are inconsistent with the AG’s characterization of them and/or have no apparent relevance.”[1491] Citing its reply brief at page 4 n2, it contends that the Attorney General is simply announcing a position and leaving it up to the ALJ or the Commission to unravel and consider the matter.

A review of the record shows that in Exhibit AG-1.58, page 1, Ms. T. Johnson acknowledges that the Uniform System of Accounts does not prevent the company from using historical net charge-offs as a basis to estimate future uncollectible costs for accrual of the Uncollectible Accounts provision. On page 4 of this exhibit, Ms. Johnson acknowledged that the C360 implementation impacted the 2019 charge-offs. On that basis, this PFD concludes that Mr. Coppola reasonably excluded 2018 and 2019 from the three-year average. While DTE prefers the calculation performed with 2019-2021 data, its objection appears to be based on 2021 data, which Mr. Coppola did not use in his analysis. On this basis, the company’s preference to use 2019 through 2021, when it acknowledges issues with both 2019 and 2021, is not a reason to reject Mr. Coppola’s analysis.

[1490] DTE brief, 197-198.
[1491] DTE reply, 148.

6. Regulated Marketing (Exhibit A-13, Schedule C5.9)

DTE witness Burns testified in support of the company's requested O&M expense allowance of $24 million as shown in Exhibit A-13, Schedule C5.9, line 18.[1492] The only disputed item on this schedule was the projected cost of $183,000 for the residential battery pilot on line 15. Because this PFD does not recommend approval of the residential battery pilot, as discussed below, this PFD concludes that the projected costs should be excluded from rate base.

7. Corporate Support Group (Exhibit A-13, Schedule C5.10)

a. Staff shift of IT capital costs to O&M

For certain of the IT program projected capital expenses that Staff found unsupported as capital expenditures with reference to the company's capitalization policy, Staff, for consistency, is willing to include in O&M expenses. This PFD notes that a more extensive evaluation of the company's capitalization policies is recommended by this PFD, with the expectation it will provide for more complete evaluation of the company's projected spending in rate cases. That having been said, reclassifying DTE capital expense projections as O&M raises additional issues whether DTE will actually spend the projected amounts or find alternatives for the additional funding. Between rate cases, DTE clearly has incentives to reduce its O&M expenses. Nonetheless, the amounts Staff proposes to transfer are not large, and this PFD appreciates Staff's continued focus on consistency. Thus, this PFD concludes it is reasonable to increase the O&M expenses by the amount requested by Staff.

[1492] 7 Tr 2499-2501.

b. Staff IT O&M expense reductions

Staff's recommend capital disallowances were accompanied by recommended O&M expense reductions associated with the capital projects as shown in Exhibits S-12.3, 12.4 and 12.6. Staff also objected to DTE's basis of projecting O&M costs for IT projects using a baseline of 10%, when actual O&M costs fall within a range of 6-13%. Dr. Wang explained Staff's additional 0.5% reduction adjusts DTE's O&M expense assumptions to the midpoint of the 6-13% range, 9.5%.[1493]

In rebuttal, Ms. Uzenksi objected to Staff's recommended disallowances of costs associated with capital expense projections as well as the additional 0.5% adjustment. Ms. Uzenksi testified that because DTE projected its O&M expense for IT based on 2020 expenses adjusted for inflation, the company's O&M expense did not include the amounts at issue and they should not be disallowed.[1494] Regarding Staff's additional 0.5% adjustment, she presented Schedule HH2 of Exhibit A-43, and testified that Staff wrongly assumes all IT O&M is related to capital projects.[1495] DTE relies on Ms. Uzenski's testimony in its brief.[1496]

In its brief, Staff revised its O&M expense reduction from $11.2 million to $6.86 million.[1497] Staff addressed DTE's rebuttal, disputing that it established an independent method for projecting IT O&M costs. Staff argues:

> Though it claims much of IT O&M costs are for IT expenses that are unassociated with a capital project, . . . there is little information provided in the rate case to detail what IT O&M costs actually support. [1498]

[1493] 8 Tr 5236.
[1494] 7 Tr 2777-2778.
[1495] 7 Tr 2778-2779.
[1496] DTE brief, 129-130.
[1497] Staff brief, 171-172.
[1498] Staff brief, 170.

Staff characterizes the company's IT O&M costs as "a black box with no clarity on the included costs and what they cover." Staff further explains that with the increased capital IT spending, O&M costs should decrease, while "the Company's methodology for projecting IT O&M ensures that these costs will only grow with each rate case."[1499] Nonetheless, it argues:

> In the absence of clearer information regarding IT O&M and the costs included within it, the discovery responses received by Staff that underly its recommended disallowances are the most concrete data provided by the Company. Staff recommends the ALJ and Commission adopt its proposed O&M disallowance of $2,876,229 in the test year.[1500]

This PFD finds Staff's analysis persuasive and concludes that its adjustments should be adopted. Additionally, as Staff notes, the IT O&M presentation by DTE is certainly not transparent. Particularly given the capitalization issues Staff raised, the Commission should ensure that a separate schedule is presented, reconcilable to the company's IT capital expense projections. Ms. Uzenski's testimony that O&M expense projections associated with disallowed projects are somehow not part of the company's O&M expense plans only exacerbates the concerns Staff has identified regarding this expense category. As a reminder, DTE's capital expense projection for the bridge period and test year is approximately $439 million.

8. Employee Pensions & Benefits (Exhibit A-13, Schedule C5.11)

The disputed items in this category involve DTE's test year healthcare and pension expense projections.

[1499] Staff brief, 170-171.
[1500] Staff brief, 171.

a. Healthcare

On behalf of DTE, Mr. Cooper testified that healthcare expense is projected to increase from $41.4 million in the historic test year to $55.5 million in the projected test year.[1501] He testified that the increase reflected both a normalization of 2020 healthcare expense to compensate for the effects of the COVID-19 pandemic and an adjustment to reflect a historical average of constant dollar costs.[1502] Mr. Cooper explained that the result was further adjusted for projected medical cost increases of 5.5% in 2021, 5.0% in 2022, and 4.5% in 2023.[1503]

Mr. Cooper explained that the pandemic resulted in unusually low levels of healthcare claims and non-recurring costs associated with COVID-19 testing and other measures.[1504] He opined that these pandemic-related distortions could be corrected by adjusting the company's 2020 healthcare expense with an increase of $3.2 million.[1505]

Mr. Cooper also opined that the year-to-year volatility of actual healthcare costs makes using any one historical test period's healthcare expense an unreliable starting point.[1506] Accordingly, he explained that a constant dollar normalization adjustment of $3.8 million for the 2020 healthcare expense was needed to eliminate the volatility of costs by quantifying the historical healthcare costs per employee as adjusted for national healthcare cost trends.[1507] Mr. Cooper calculated the constant dollar normalization adjustment by taking the company's actual healthcare costs for 2016-

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[1501] 7 Tr 1796; see also Exhibit A-13, Schedule C5.11.
[1502] 7 Tr 1796.
[1503] 7 Tr 1796.
[1504] 7 Tr 1797, 1799.
[1505] 7 Tr 1799.
[1506] 7 Tr 1799.
[1507] 7 Tr 1799-1800.

2020 and dividing them by the simple average of employees at the beginning and end of each year to determine the healthcare cost per employee in each year.[1508] Mr. Cooper then adjusted the per-employee cost for each year by the percent increase in medical cost trends as reported by PricewaterhouseCoopers LLP.[1509] He explained that he used the five-year average cost per employee on a constant dollar basis and multiplied it by the average number of employees in 2020 to generate the total constant dollar average active healthcare cost.[1510] Mr. Cooper specified that this process revealed the need for a $3.8 million adjustment.[1511] Notably, Mr. Cooper acknowledged that the Commission previously declined to adopt a constant dollar cost adjustment in a recent DTE Gas case stating instead that a multi-year average adequately captures the volatility of the expense.[1512] However, he criticized this approach stating that it fails to recognize the impact of volatility and fails to address whether the historical test period is a representative starting point for adjustments.[1513] He compared his constant dollar adjustment calculations to the conversion of historical nominal prices into real prices that allow for a comparison of costs among years without the distortion of changes in price levels.[1514]

Mr. Cooper specified that the future medical plan trends for 2021-2023 were derived from projections from Willis Towers Watson PLC, and those annual trends were

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[1508] 7 Tr 1802.
[1509] 7 Tr 1803. Mr. Cooper specified that he adjusted the 2020 trend of 6.0% downward by 0.5% to account for the impact of the company's wellness program in that year.
[1510] 7 Tr 1803.
[1511] 7 Tr 1803.
[1512] 7 Tr 1804.
[1513] 7 Tr 1804.
[1514] 7 Tr 1805.

adjusted downward by 0.50% to reflect expected savings from the company's employee wellness program.[1515]

Mr. Coppola sharply criticized the company's constant dollar cost adjustment. Mr. Coppola testified that the company's 2020 calculated constant dollar adjusted cost per employee of $11,454 was "divorced from reality" because it was 8.4% higher than the actual adjusted cost determination for 2020 of only $10,566 per employee.[1516] Mr. Coppola opined that Mr. Cooper's approach is "simply compounding inflationary increases on top of inflationary increases[,]" and he urged the Commission to reject what he characterized as the company's "brazen attempt to inflate forecasted O&M expenses."[1517] Rather than adopting DTE's projection, he opined that $48.5 million was an appropriate forecast for healthcare expense in the projected test year.[1518] Mr. Coppola explained that he arrived at that figure using the actual average cost of healthcare per employee from 2016 through 2019, as well as the combined average of 2020 through 2021 to take into consideration that many procedures were postponed from 2020 to 2021 because of the pandemic.[1519] He explained that he then calculated an average annualized increase in the cost per employee of 2.5% since 2016, which he then applied to future years.[1520] Accordingly, he urged the Commission to adopt his projection of $48.5 million and remove $9.5 million from DTE's projected O&M expenses.[1521]

[1515] 7 Tr 1806.
[1516] 8 Tr 4867.
[1517] 8 Tr 4867.
[1518] 8 Tr 4867; see also Exhibit AG-1.47.
[1519] 8 Tr 4868.
[1520] 8 Tr 4868.
[1521] 8 Tr 4869.

In rebuttal, Mr. Cooper disagreed with Mr. Coppola's decision to use a different adjustment for the effects of the COVID-19 pandemic, to reject the constant dollar cost adjustment, and to utilize a four-year average of healthcare cost increases.[1522] He argued that Mr. Coppola's COVID-19 adjustment that averaged together the company's costs from 2020 and 2021 unreasonably assumes that medical treatments not performed in 2020 were performed in 2021 and also ignores the potential for delays in treatment to increase total costs.[1523] Mr. Cooper addressed Mr. Coppola's statement that the constant dollar adjustment improperly compounded inflationary pressures stating that Mr. Coppola "seems to be confusing the difference between the need to establish an accurate normalized starting point . . . with the escalation of that starting point for healthcare cost related inflation in future years."[1524] He contended that the constant dollar adjustment is necessary to set a proper starting point for volatile spending by restating historical healthcare costs per employee.[1525] Mr. Cooper also critiqued Mr. Coppola's decision to use the company's average change in healthcare costs per year to adjust expense for the test year asserting that the volatility in historic costs "renders the use of the average annual changes in Active Healthcare cost meaningless."[1526] He also added that the "most obvious flaw" in Mr. Coppola's projection was that it was $2.8 million lower than DTE's actual healthcare expense incurred in 2021.[1527]

[1522] 7 Tr 1866.
[1523] 7 Tr 1871-1872.
[1524] 7 Tr 1874.
[1525] 7 Tr 1874.
[1526] 7 Tr 1872.
[1527] 7 Tr 1867.

While not conceding the propriety of Mr. Coppola's forecasting method, Mr. Cooper explained that there were several corrections that could be made to improve it. He explained that the $3.1 million reduction for 2020 costs attributed to COVID-19 needed to be eliminated, the correct number of DTE employees for 2021 had to be used, and as a result the historical average annual percentage change in costs per employee changed to 3.0%.[1528] With those corrections, Mr. Coppola's forecast would increase from $48.5 million to $50.3 million, which Mr. Cooper opined was "still an unreasonably low level" but was nevertheless "superior to the flawed projection provided by Witness Coppola."[1529]

In its initial brief, DTE summarizes points from its direct and rebuttal testimony.[1530] In her initial brief, the Attorney General cites several discovery responses to support her contention that Mr. Cooper's rebuttal arguments were not credible, particularly regarding adjustments to 2020 active healthcare expense.[1531] The Attorney General also argues that DTE's claims that medical procedures postponed because of the pandemic could continue into 2022 were meritless because the utility could not provide relevant information to support that assertion.[1532] Further, the Attorney General critiques the company's preference for average national healthcare cost increase rates rather than for the historical average of the company's own medical cost trends.[1533] Finally, the Attorney General argues that DTE's claims about the volatility of healthcare costs per employee was incorrect given that the graph provided by DTE showed a

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[1528] 7 Tr 1870-1871.
[1529] 7 Tr 1871; see also Exhibit A-35, Schedule Z3.
[1530] DTE brief, 206-211.
[1531] Attorney General brief, 30; see also AGDE 11.346a, 11.346b, and 11.346c.
[1532] Attorney General brief, 31.
[1533] Attorney General brief, 31.

steady trend until 2020 and 2021, which only broke the trend because of pandemic-related distortions.[1534]

In its reply brief, DTE asserts that the discovery responses cited by the Attorney General supported the company's position.[1535] DTE also reaffirms that healthcare costs per employee are volatile asserting that the graph provided in its testimony showed that costs decreased in 2014, 2016, 2018, and 2020, and rose dramatically in 2021.[1536]

In her reply, the Attorney General opines that the main takeaway from this issue was that DTE "continues to try to find creative ways to increase projections to get to desired, inflated numbers[;]" further, she asserts that DTE's constant dollar adjustment and subjective COVID-19 related adjustments exemplify the utility's attempt to inflate healthcare expense.[1537] The Attorney General also responds to DTE's assertion that her projection for healthcare expense was lower than DTE's actual 2021 expense stating that DTE chose 2020 as its historical test year, so she is only using the starting point DTE selected.[1538] She opines that the DTE cannot "have its cake and eat it too" by using 2020 historical comparisons when advantageous and then switching to comparisons to 2021 when advantageous.[1539] In a similar vein, the Attorney General faults DTE for making a selective comparison to 2021 actual healthcare expense after arguing that its constant dollar normalization is necessary because any historical test period is potentially unreliable as a starting point.[1540] Finally, the Attorney General

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[1534] Attorney General brief, 32; see also Table 4 at 7 Tr 1874.
[1535] DTE reply, 157.
[1536] DTE reply, 157; see also Table 4 at 7 Tr 1874.
[1537] Attorney General reply, 37.
[1538] Attorney General reply, 38.
[1539] Attorney General reply, 38.
[1540] Attorney General reply, 38.

emphasizes that the Commission recently rejected similar attempts by DTE to use constant dollar normalization, and urges the Commission to do so again.[1541]

This PFD recommends rejecting DTE's proposed constant dollar normalization adjustment. This PFD notes that the Commission recently rejected a proposal by DTE Gas to use constant dollar normalization to project healthcare expense stating that it was not persuaded by that company's argument that a constant dollar normalization adjustment was appropriate and instead finding that a multi-year average adequately captures the volatility of the expense.[1542] For similar reasons, this PFD is not persuaded by DTE's arguments in this case. While not dispositive, this PFD also notes that while the company stressed that normalization was intended to set a proper starting point for adjustments, it failed to thoroughly address the Attorney General's concern that it could potentially result in compounding inflationary pressures, particularly when the normalization calculations used by DTE included adjustments for national healthcare cost trends when calculating the five-year average cost per employee.[1543]

This PFD recommends adopting the more conventional projection proposed by the Attorney General, albeit with the corrections suggested by DTE. While not conceding the propriety of the Attorney General's approach, DTE suggested corrections to the Attorney General's model relating to a COVID-19 adjustment, the correct number of DTE employees for the year 2021, and the resulting annual average percentage change in the company's healthcare cost per employee.[1544] Regrettably, the Attorney General's briefing was silent as to whether she accepted or opposed the company's

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[1541] Attorney General, 39.
[1542] See December 9, 2021 order in Case No. U-20940, p 156-157.
[1543] See 7 Tr 1800; see also Exhibit A-13, Schedule C.5.11.4 Revised.
[1544] 7 Tr 1870-1871; see also Exhibit A-35, Schedule Z3.

corrections. However, this PFD believes that DTE's suggested corrections were proposed in good faith and recommends adopting the resulting healthcare expense projection of $50.3 million, which is a reduction of approximately $5.2 million from the company's projection.[1545]

b. Pension (Attorney General adjustment vs. deferred accounting request)

On behalf of DTE, Mr. Cooper testified that pension expense relates to the company's defined benefits plan, and he detailed the five different components of pension costs: service costs, interest costs, expected return on assets, unrecognized gains and losses, and prior service costs.[1546]

He defined interest costs as the increase in the projected benefit obligation (PBO) due to the passage of time during the current period.[1547] In turn, Mr. Cooper defined the PBO as the actuarial present value of benefits attributable to the pension benefit formula and service accrued to date discounted back to current dollars at a discount rate.[1548] He specified that a rate of 2.57% was used to determine the PBO at the end of the historical test year and that the interest costs for the projected test year were also based on that rate.[1549] Mr. Cooper testified that the 2.57% rate was based upon the assumption that the interest rates for high quality corporate bonds at the end of 2022 will be unchanged from the prevailing rates in late 2020.[1550] He also testified

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[1545] See Exhibit A-35, Schedule Z3.
[1546] See 7 Tr 1784-1786. Only interest costs and the expected return on assets will be detailed in this PFD because those were the only disputed components of DTE's pension expense.
[1547] 7 Tr 1784.
[1548] 7 Tr1784-1785.
[1549] 7 Tr 1785.
[1550] 7 Tr 1785.

that the discount rate used to measure interest and service costs for the 2020 historical test period was 3.28% based upon the interest rate environment at the end of 2019.[1551]

Regarding the expected return on assets, Mr. Cooper explained that it is "an estimate of the expected investment return, during the current period, on the Market Related Value of the assets invested in the pension trust at the beginning of the year adjusted for both planned funding and benefit payments for the year."[1552] Mr. Cooper testified that while returns fluctuate from year to year, the projected rate of return is based on long-term market expectations to avoid large variations.[1553] He asserted that DTE's expected annual return was 7.10% for the 2020 historical test year, and the expected rate decreased to 7.00% in 2021, 6.80% in 2022, and 6.70% in 2023.[1554] Mr. Cooper attributed the diminishing return projections for 2021-2023 to a planned increase in fixed-income asset allocation because of a projected increase in funded status.[1555]

Additionally, Mr. Cooper explained that fluctuations in the actual rate of return or in the discount rate could "have a significant impact on the Company's actual annual pension costs."[1556] For example, he specified hypothetical scenarios in which those values were meaningfully higher than the company's current projections, and the result was that the projected pension expense became negative.[1557] He testified that these analyses demonstrated the potential for "extreme volatility" in the utility's pension costs,

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[1551] 7 Tr 1785.
[1552] 7 Tr 1785.
[1553] 7 Tr 1785.
[1554] 7 Tr 1786.
[1555] 7 Tr 1786.
[1556] 7 Tr 1788.
[1557] 7 Tr 1789; see also Exhibit A-13, Schedule C5.12.2.

and it was possible for the company to incur negative pension costs during the projected test year.[1558] Mr. Cooper testified that the company anticipated pension expense of $9.2 million in the projected test year.[1559] However, to address the possibility of a negative pension expense, the company proposed the adoption of a deferral mechanism for pension costs similar to that in place for the company's other post-employment benefit (OPEB) expense.[1560] Mr. Cooper explained that if pension costs were treated as a regulatory asset or liability, then pension expense for the projected test year would be eliminated.[1561]

Ms. Uzenski offered further details on DTE's proposal testifying that actual pension expense should be treated as regulatory asset if positive, and as a regulatory liability if negative, such that the amount reflected in rates is zero with actual expense deferred for future recovery or refund.[1562] She opined that the net deferred amount could be carried on the company's balance sheet for future review similar to that of OPEB deferral; further, she asserted that this proposal is consistent with the approved deferral of pension expense for DTE Gas.[1563]

Mr. Coppola took issue with the company's declining projected return on pension assets arguing that it "is not justified by the actual returns earned by the plan assets over the past 12 years."[1564] Mr. Coppola testified that from 2010 to 2021, DTE's pension assets earned an average return of 8.94%; accordingly, he opined that the utility's

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[1558] 7 Tr 1790.
[1559] 7 Tr 1788.
[1560] 7 Tr 1790.
[1561] 7 Tr 1790.
[1562] 7 Tr 2712.
[1563] 7 Tr 2712; see also December 9, 2021 order in Case No. U-20940, p 154.
[1564] 8 Tr 4870.

projected return of 7.00%—declining to 6.70% by 2023—was “a far cry from the long-term actual return achieved.”[1565] He criticized the company’s claim that the declining return rate was attributable to a more conservative mix of fixed-income investments explaining that in response to discovery DTE provided target asset allocations for 2023 that “do not change much from the actual mix in 2021.”[1566] Mr. Coppola testified that the opposite actually occurred with the company showing a slight increase in risker equity investments and a slight decrease in safer fixed-income investments.[1567] Additionally, he criticized the utility’s decision to use a discount rate of 2.57% within its actuarial analysis stating that this rate was “outdated” when used by the company because DTE’s own 2021 10K form showed a higher discount rate of 2.91%.[1568] He opined that using a higher discount rate would result in lower pension expense.[1569]

Mr. Coppola asserted that through discovery, he asked the company to perform an analysis using the actual plan asset return of 8.4% in 2021, the 2.91% discount rate, and maintaining the expected rate of return at 7.00% in the subsequent years.[1570] He explained that the cumulative result of that analysis was that pension expense for the projected test year went from $9,145,000 to a negative amount of $8,297,000 for a net change of $17,442,000.[1571] Mr. Coppola concluded that DTE’s assumptions for the discount rate, actual return on assets in 2021, and projected return on assets in 2022

[1565] 8 Tr 4870.
[1566] 8 Tr 4870.
[1567] 8 Tr 4870-4871.
[1568] 8 Tr 4871.
[1569] 8 Tr 4871.
[1570] 8 Tr 4872.
[1571] 8 Tr 4872; see also DR AGDE-8.270 included with Exhibit AG-1.48.

and 2023 were all "outdated or unreasonable" and he recommended adopting his updated analysis that would lower pension expense by $17,442,000.[1572]

In rebuttal, Mr. Cooper rejected Mr. Coppola's recommendation citing three flaws. First, he asserted that Mr. Coppola's projection is "based on sensitivities prepared by the Company in response to the AG's Discovery request and do not reflect the same analytical rigor that would be used in a formal projection of pension costs by the Company's independent actuaries."[1573] Second, that these sensitivities included, at the request of the Attorney General, an "unreasonable assumption" that the expected return on assets would remain at 7.00% for the entire projected period.[1574] Third, he pointed out that Mr. Coppola's proposal was at odds with DTE's proposal to implement a pension expense deferral mechanism.[1575] Mr. Cooper also asserted that the Commission previously rejected cost projections like Mr. Coppola's that were not based on measurements and calculations performed by independent actuaries.[1576] Mr. Cooper critiqued Mr. Coppola's partial reliance on the utility's actual return on pension assets for the last 12 years; he explained that asset mixes varied over that timeframe and that 12 years was "simply too short of a time frame to determine future likely returns."[1577] Mr. Cooper also rejected Mr. Coppola's assertion that fixed-income allocations were actually decreasing stating that Mr. Coppola "is apparently confusing actual asset

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[1572] 8 Tr 4873; see also DR AGDE-8.270 included with Exhibit AG-1.48.
[1573] 7 Tr 1876.
[1574] 7 Tr 1876.
[1575] 7 Tr 1876.
[1576] 7 Tr 1877, citing *In the matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered February 28, 2017 (Case No. U-17990) p 97.
[1577] 7 Tr 1878.

allocations with target asset allocations."[1578] He opined that an asset allocation table provided with his testimony demonstrated that the pension assets were increasingly being allocated to fixed-income assets and away from more speculative equities.[1579]

Mr. Cooper's rebuttal also introduced the most recent projection of pension costs prepared by DTE's actuary, which reflects the actual funded status as of December 31, 2021, updated asset allocations, and a 2.91% discount rate.[1580] He explained that the actuary showed updated estimated return on assets of 7.00% in 2021, 6.80% for 2022, and 6.60% in 2023; the pension costs for the projected test period were negative $0.2 million and net pension costs were $0.6 million.[1581] Mr. Cooper reiterated that the pension deferral mechanism proposed by Ms. Uzenski would eliminate the uncertainty of future pension expense.[1582]

In its initial brief, DTE summarizes the arguments made in testimony and requests that the Commission either adopt its updated pension expense projection of $0.6 million or alternatively adopt a pension expense deferral mechanism.[1583]

In her initial briefing, the Attorney General asserts that the analysis used by Mr. Coppola is sufficient, notwithstanding the fact that it was not generated by DTE's actuary, because the analysis relied on information provided by DTE's actuary and in response to discovery requests DTE was unable identify any major shortcomings in the analysis.[1584] Further, the Attorney General disputes DTE's claim that its investment

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[1578] 7 Tr 1881.
[1579] 7 Tr 1881.
[1580] 7 Tr 1882; see also Exhibit A-35, Schedule Z6.
[1581] 7 Tr 1882; see also Exhibit A-35, Schedule Z6.
[1582] 7 Tr 1883-1884.
[1583] DTE brief, 201-205.
[1584] Attorney General brief, 32-33; see also Exhibit AG-1.54.

policies were becoming more conservative stating that discovery responses and minutes from DTE's Pension Investment Committee showed no change in direction.[1585] Consequently, the Attorney General opines that "[r]ather than Mr. Coppola, it is Mr. Cooper who seems confused as to which asset mix the Company wants to pursue."[1586] She also argues that the utility cannot justify a projected 6.70% return on investment because discovery responses reveal that the average return of the three major asset components (equities, fixed-income, and alternative investments) over a 12-year period all exceeded that amount.[1587] The Attorney General also contends that the Commission should not be dissuaded from accepting her position merely because pension expense may become a negative value; she asserts that the Commission previously accepted a negative OPEB expense for inclusion in rates.[1588] The Attorney General concludes that the Commission should adopt her projection of pension expense or alternatively, accept DTE's revised projection which she characterizes as "more acceptable" than the utility's original projection.[1589]

In its reply, DTE takes issue with the Attorney General's assertion that the utility could not find "major shortcomings" in the analysis prepared by the company at the Attorney General's request; DTE explained that it was unable to have its actuaries fully prepare and analyze the sensitivities requested by Attorney General because of time constraints.[1590] DTE also criticizes the Attorney General's efforts to cast doubt on the company's arguments by referencing discovery responses asserting that the Attorney

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[1585] Attorney General brief, 33; see also Exhibit AG-1.55, pages 20-24.
[1586] Attorney General brief, 34.
[1587] Attorney General brief, 34; see also Exhibit AG-1.56, pages 3-4.
[1588] Attorney General brief, 35; see also Case U-20697, which the Attorney General cited as Exhibit A-51.
[1589] Attorney General brief, 36-37.
[1590] DTE reply, 151.

General either mischaracterizes or ignores the content of the responses.[1591] DTE further objects to the Attorney General's reliance on information that is not in the record in this proceeding to the extent that the Attorney General references the Commission's acceptance of a negative OPEB expense in another case.[1592] DTE again requests that the Commission reject the Attorney General's position and either accept its updated projection of a $0.6 million pension expense or alternatively create a deferral mechanism.[1593]

In her reply, the Attorney General reiterates the arguments and points discussed in her initial brief.[1594]

This PFD recommends the creation of a deferral mechanism for pension expense to alleviate the uncertainty surrounding the volatility of pension expense projections. Indeed, the volatility in pension expense is evidenced not just by the gap between the company's projection and the Attorney General's preferred projection, but also by the gap between the company's initial projection and its own updated projection. While the company and the Attorney General disagree significantly on the projected pension expense, there appears to be consensus that the pension expense could ultimately be a negative value. Further, creating a deferral mechanism for pension expense in this case aligns with the Commission's treatment of pension expense for DTE Gas, and adopting a consistent approach for these related utilities is appropriate.[1595] Accordingly, this PFD recommends treating the pension expense as a

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[1591] DTE reply, 151, 153.
[1592] DTE reply, 154.
[1593] DTE reply, 156.
[1594] Attorney General reply, 36-37.
[1595] See December 9, 2021 order in Case No. U-20940, p 154.

regulatory asset if positive, and as a regulatory liability if negative, such that the amount reflected in rates is zero with the actual expense deferred for future recovery or refund.

9. Incentive Compensation

In recent rate cases, the Commission has authorized partial funding for DTE's compensation programs, distinguishing between incentives linked to financial performance and those linked to objective measures. At issue in this case is DTE's request for full funding of $63.8 million it associates with its employee incentive compensation programs, as well as the recovery of an additional $5.9 million in restricted stock grants that are a part of the company's long-term incentive program. These are discussed below.

a. EICP

Mr. Cooper testified in support of DTE's recovery of its incentive compensation program costs, including the cost of "performance shares" awarded to employees under its long-term incentive plan, as well as compensation awarded under the company's short-term compensation programs, the Annual Incentive Plan (AIP) for senior management at the Vice President or director level, and the Rewarding Employees Plan (REP), for other non-represented employees.

Mr. Cooper devoted several pages of his testimony to explaining the company's compensation philosophy, and its efforts to match employee compensation packages, including incentives, to the median market compensation for comparable or peer positions, presenting Schedule K1 of Exhibit A-21. He testified that DTE's proposal to include its projected incentive compensation expense in the revenue requirement, excluding the portion related to DTE Energy's top five Executive Officers, "is based on the prevalence of incentive compensation programs and the resultant need for the Company to have total compensation programs that enable it to be competitive with other employers."[1596]

Mr. Cooper described the 2021 measures associated with the LTIP performance share grant and the short-term compensation awards under the AIP and REP, and his efforts to quantify the benefits associated with those measures.[1597] He presented his analysis in Schedule K6 of Exhibit A-21, with a total customer benefit of $105.6 million relative to the $63.8 million expense.[1598] He concluded: "While not every individual measure has quantified benefits in excess of the incentive compensation expense of the related measure, it is clear that in aggregate, the quantified customer benefits of the Company achieving Target performance levels are substantially greater than the related expense."[1599]

Mr. Cooper acknowledged that in the last DTE Gas rate case, the Commission did not include in the revenue requirement the projected costs of the incentive compensation programs associated with attainment of financial measures. Mr. Cooper testified:

> The Commission apparently rejected the inclusion of the incentive compensation expense related to the financial measures based, in part, by opining that 'DTE Gas's mere contention that customers receive benefits from well-compensated employees is insufficient to demonstrate that incentive compensation specifically tied to financial performance does not primarily benefit shareholders or that such benefits to ratepayers are commensurate with the proposed expense.'[1600]

[1596] 7 Tr 1822.
[1597] 7 Tr 1825-1840.
[1598] 7 Tr 1835.
[1599] 7 Tr 1840.
[1600] 7 Tr 1844.

He disagreed with the Commission's order, contending that the total quantified benefits of all measures exceed the aggregate expense, and that the company's total company, including the incentives, are well aligned with market medians.[1601] Mr. Cooper further addressed the Commission's decision in that DTE Gas rate case, Case No. U-20940, focusing on its determination to include only 20% of the incentive compensation associated with operating measures in the test year revenue requirement, based on analysis presented by the Attorney General in that case. He explained his objections to the approach taken in that case, and presented Schedule K7 to show DTE's average performances on its operating measures for electric operations.[1602]

Several witnesses recommended reductions to DTE's expense request. Ms. McMillan-Sepkoski explained Staff's recommendation that incentive costs associated with financial measures be excluded, citing the Commission's concerns articulated in over 12 cases that shareholders specifically benefit from financial performance measures such as return on equity and cash flow, while ratepayers benefit from non-financial measures related to reliability and customer-satisfaction.[1603] Ms. York also recommended that the Commission exclude incentive plan costs associated with financial measures.

Mr. Coppola reviewed the plan measures for the short-term and long-term plans. He testified to his "overall assessment . . . that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers." He noted that DTE's proposed expenses include $41.5 million of the total $63.8 million

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[1601] 7 Tr 1844.
[1602] 7 Tr 1841-1842.
[1603] 8 Tr 5262-5263.

(65%) related to financial metrics. Mr. Coppola recommended that the Commission exclude the incentive compensation related to financial measures.

Mr. Coppola also reviewed the operating measures and the benefit calculations presented in Schedule K6 of Exhibit A-21. He testified that $41 million of the benefits DTE ascribes to its “operating excellence” measures are “highly depended upon a more aggressive tree trimming program and capital spending program which should in turn reduce the SAIDI and CAIDI outage metrics.” He testified that 98% of the benefits DTE ascribes to the “employee engagement” measures are related to productivity gains, which may be fleeting, citing increases in employee levels from 2019. Mr. Coppola reviewed DTE discovery indicating performance levels for the 2021 metrics. He testified that these results showed that for DTE, performance on 6 out of 8 operating metrics were below target level, for DTE LLC, the corporate staff, performance was below target in 4 of 7 metrics, and for the separate nuclear employee operating metrics, performance was below target on 4 out of 6 metrics. He summarized these results in Exhibit AG-1.49. Mr. Coppola considered the uncertainty created by these and similar results for the 2016-2020 time period shown in schedule K7 [1604]create uncertainty whether DTE will achieve sufficient performance to justify the target level payouts for the operating measures it is asking ratepayers to fund. He recommended that ratepayer funding for operational measures be limited to 60% of the target level based on the average over the past five years, 2017-2021.[1605]

[1604] 8 Tr 4879.
[1605] 8 Tr 4880-4881.

Mr. Zakem had an alternate recommendation. He recommended that the funding for the employee incentive compensation be limited to funding for those measures with benefits exceeding cost. In his Table 1 at 8 Tr 4497, he listed measures with costs exceeding the assigned benefits, testifying that the total cost for these eight measures is $40.3 million, while the total quantified benefits shown on Mr. Cooper's Schedule K6 is only $1.9 million.[1606] He presented Table 2 at 8 Tr 4500 to show that excluding the negative-value measures achieves "a superior result because it increases the net gain while at the same time reducing the cost of the program."[1607]

In rebuttal, Mr. Cooper addressed these recommendations. He reiterated in response to Ms. McMillan-Sepkoski, Mr. Coppola, and Ms. York, his view that financial measures benefit ratepayers as well as shareholders and therefore compensation for financial measures should be funded by ratepayers.[1608] He took issue with Staff's adjustment for including $1.1 million in the LTIP for the nuclear generation program, asserting that the stock award to the eligible employees in that program is based on operating measures. And he took issue with Mr. Coppola's analysis for not including performance above target levels on some operating measures to offset failures to meet target level performance in other operating measures. He presented Schedule Z1 of Exhibit A-35, akin to Schedule K3 of Exhibit A-21, to show that "actual weighted performance for the last five years was 96.5% for the AIP and 83.4% for the REP for a combined average of 89.9%."[1609] He also asserted that it would not be reasonable to

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[1606] 8 Tr 4497.
[1607] 8 Tr 4500.
[1608] 7 Tr 1850-1851, 1855-1856, 1865.
[1609] 7 Tr 1860.

assume DTE would achieve only 60% of target performance levels in the test year.[1610] Mr. Cooper also took issue with Mr. Coppola's testimony that productivity gains from employee engagement may be fleeting, contending that Mr. Coppola's presentation of increasing employment counts ignored generation plant employee counts that are decreasing.

Mr. Cooper presented an alternative deferral proposal, based in part on the recent DTE Gas rate case. He noted that the Commission adopted a deferral mechanism in that case, and explained why he did not recommend the same deferral mechanism:

> The deferral process approved by the Commission in Case No. U-20940 prescribed that the actual performance for the operating measures be capped at 100% of Target. This results in asymmetrical distribution of risks. That is, if the Company's overall performance is less than assumed in setting rates, it must refund the difference, but if operating performance is above Target, it can only collect the difference between the level assumed in rates and 100%, while the actual expense could be greater than 100%. As a result, the Company will be required to absorb costs that were the result of the Company achieving extraordinary performance in its operating measures. My primary proposal regarding the incentive compensation expense related to the operating measures is to include 100% based on the assumption that Target is the most likely outcome but with the risk that some years will be less than Target and some years will be more than Target. Requiring the Company to refund in those years with relatively low results but only being allowed to collect up to Target in high performance years is unreasonable. Therefore, if the Commission adopts a deferral process for incentive compensation expense, it should be modified to eliminate the 100% performance level cap.[1611]

Regarding Mr. Zakem's focus on measures with benefits in excess of cost as measured by Mr. Cooper in Schedule K6, Mr. Cooper objected to his recommendation based on

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[1610] 7 Tr 1861.
[1611] 7 Tr 1862.

his view that operational measures have benefits that cannot be quantified, using the objective focused on customer formal complaints as an example.[1612]

In its brief, DTE urges the Commission to adopt Mr. Cooper's recommendations, reprising Mr. Cooper's testimony extensively.[1613] DTE disputes that more than a dozen prior Commission decisions declining to include compensation for achieving financial measures in the customer revenue requirement constitute a policy, or even precedent. It argues that the Commission has chosen to evaluate the evidence in each case.[1614] DTE argues "the Commission's repeated denial of total incentive compensation expense is inconsistent with the reasonableness of total compensation," citing Mr. Cooper's analysis and Schedule K1 to show that the total compensation including the incentives allows DTE to pay median compensation to its employees.[1615] DTE objects to Staff's exclusion of the nuclear generation program LTIP stock grants, arguing that "with regard to the nuclear generation operating measures," the cost is not different from the operational measures included in the short-term compensation programs.[1616] DTE's reply brief makes similar arguments.[1617]

DTE argues that Mr. Coppola's proposal ignores above target-level performance for some measures, citing Mr. Cooper's testimony, Schedule Z1 of Exhibit A-35, and Schedule K7 of Exhibit A-21.[1618] It contends the Attorney General's argument was rejected by the Commission in Case Nos. U-18255 and U-20162, although DTE

[1612] 1863-1865.
[1613] DTE brief, 211-221; also see DTE reply, 157-163.
[1614] DTE brief, 213.
[1615] DTE brief, 215-216.
[1616] DTE brief, 217.
[1617] DTE reply, 159-160.
[1618] DTE brief, 218.

acknowledges the Commission's order in case No. U-20940 adopted the Attorney General's recommended reduction based on past performance in that case, with an additional two-way tracker.[1619] As did Mr. Cooper, DTE contends it would agree to a deferral mechanism in this case, with the additional modification that there is no cap on funding at the 100% of target level.

Although DTE argues that prior Commission decisions are not relevant because this case must be evaluated on the evidence, DTE responds to Energy Michigan's recommendation by arguing that evaluating each measure separately is inconsistent with the Commission's prior decisions on this issue

> Energy Michigan's proposal is anew, 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.[1620]

It also argues that certain measures evade quantification, citing Mr. Cooper's example of customer complaints.[1621]

Staff's brief relies on Ms. McMillan-Sepkoski's testimony, and further responds to Mr. Cooper's rebuttal. Staff argues that it does not dispute the overall reasonableness of employee compensation, "but instead argues that there should be a distinction on who pays based on the metrics included." It notes the Commission "has long held that shareholders, not ratepayers, must pay for incentives related to increasing profits," and adds that "no party has given a reason for the Commission to reverse that stance." Staff disputes that its adherence to prior Commission decisions means that it is ignoring

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[1619] DTE brief, 219-220.
[1620] DTE brief, 220.
[1621] DTE brief, 220.

evidence of reasonableness, citing as an example the Commission's order in Case No. U-20162, which concluded that financial measures have not been shown to benefit ratepayers.[1622] Staff argues that although the nuclear generation variant of the LTIP is based only 20% on shareholder return, the value of the performance shares awarded depends on the financial operation of the company, citing Exhibit S-8.3, page 3.[1623]

The Attorney General urges the Commission to adopt Mr. Coppola's recommendations. It responds to Mr. Cooper's testimony regarding employee counts by noting that employee counts are still increasing in Mr. Cooper's table at 7 Tr 1857, also noting that DTE is shutting down coal plants, which should lead to reduced employee counts without regard to productivity increases.[1624] In her reply brief, the Attorney General confirms that excluding the $1.1 million nuclear generation LTIP was intentional on Mr. Coppola's part, citing Exhibit AG-1.52.[1625] The Attorney General briefly discusses DTE's deferral proposal, objecting to a deferral proposal that would allow it to recover for performance levels above 100% of target.

ABATE cites the Commission's order in Case No. U-20561 explaining that it has "unequivocally and consistently disallowed incentive compensation costs tied to financial measures."[1626] It also cites the Commission's order in Case No. U-20963, also rejecting financial measures. ABATE argues that DTE's proposal to recover the incentive costs associated with its financial measures are unreasonable. In its reply

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[1622] Staff brief, 176-177.
[1623] Staff brief, 179-180.
[1624] Attorney General brief, 37-40.
[1625] Attorney General reply, 39-40.
[1626] ABATE brief, 56, citing May 8, 2020 order, Case No. U-20561, pages 17-19.

brief, it further argues that DTE has not provided an adequate justification for the Commission to deviate from its prior decisions.[1627]

Energy Michigan argues that the Commission should adopt Mr. Zakem's recommendation. It emphasizes that Mr. Zakem's recommendation is based on DTE's own numbers, and disputes that the Commission's prior decisions justify any expenditures up to the level of benefits:

The Commission has stated that 'employee incentive plans require a showing that the plan will not result in excessive rates and that the benefits to ratepayers from the bonus and incentive plans, at a minimum, will be commensurate with the programs' costs.' Interpreting this language to exclude incentive plan components whose costs exceed their benefits (according to the utility's own exhibit) cannot be fairly characterized as 'unreasonable."

As noted above, DTE's reply largely reiterates the points made in its initial brief. It accuses Energy Michigan of misunderstanding or incorrectly characterizing its position.[1628]

This PFD finds that Staff's recommendation should be adopted in this matter. DTE presented the same basis analysis in this case as it has in prior cases. It does not purport to have new evidence, notwithstanding its insistence that the Commission has to review this record anew without regard to its decisions in prior cases. Starting with DTE's request to include costs associated with its financial measures, the company's benefit cost analysis is not persuasive because it does not event attempt to isolate the

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[1627] ABATE reply, 17-18.
[1628] DTE reply, 162-163.

potential marginal contribution of its employee incentives to the benefits ascribed, but instead assumes that benefits funded heavily by ratepayers are entirely due to the incentive programs. DTE's assumption of benefits for maintaining the company's credit rating are a prime example of this unsupported presumption. Mr. Cooper assigns a benefit of $18.5 million to achieving the company's "Cash from Operations" measure based on the potential interest cost of a credit downgrade:

> The primary benefit of achieving the Case from Operations measure is the Company maintaining its BBB+ debt rating from Standard & Poor's and comparable ratings by the other major debt rating firms. The current yield spread between utility A rate bonds compared to BBB rated bonds is 22 basis points. Based on the long-term debt included in the capital structure sponsored by Company Witness Vangilder, a downgrade in the Company's credit rating would increase the Company's annual interest costs by $18.5 million.[1629]

Yet, in Case No. U-20561, for example, the Commission included after-tax income of $977,000,000 in the revenue requirement to cover DTE's capital costs, in addition to revenues to meet DTE's projected operating expenses in that case. Other statutory provisions and Commission orders protect DTE's ability to meet its debt obligations, including its ability to obtain rate relief within 10 months of filing. To attribute DTE's ability to maintain its debt rating, by even one notch, to the incentive compensation provision ignores these significant contributing factors. Thus, this PFD concludes that DTE has not established that ratepayers benefit from the financial measures.

[1629] 7 Tr 1835.

Regarding the LTIP nuclear generation program, as Staff argues, that program is targeted overall at motivating employees to enhance the value of the company's stock, which they have an ownership interest in. As shown in Exhibit S-8.3, although performance objectives are required to be met before performance shares are vested, the incentive is intrinsically linked to the potential to increase the value of the shares during the three-year performance period. During that period, holders of performance shares do not have voting rights, but "dividend equivalents will be credited as additional shares."[1630]

While Mr. Coppola makes an important point that shows the uncertainty associated with ratepayer support of objective measures, this PFD is reluctant to recommend that the Commission adopt the approach taken in Case No. U-20940, which also included a two-way tracker for the incentive payments. While it does give the Commission the ability to tie the company's receipt of funds to achievement of the performance objectives, it does create another issue to resolve in rate cases, i.e., the company's performance under the performance plans. In that context, this PFD notes that DTE has not presented the test year objectives, which would seem to be a prerequisite for true accountability. Based on this record, DTE would be free to revise its operational objectives. Should the commission wish to pursue the model adopted in Case No. U-20940, this PFD recommends that the Commission require a determination of the operating measures in advance, and contrary to DTE's request, limit recovery to target performance for each of the measures, as performance above that level has not

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[1630] Exhibit S-8.3, page 5.

been subject to any evaluation for any of the measures, and could exceed the median compensation levels DTE targets.

This PFD notes that notwithstanding the Commission's focus on operational measures for ratepayer funding, DTE has increased the size of its employee incentive compensation expense by approximately 34%, from $47.6 million in Case No. U-20561 to $63.8 million in this case, but has increased the portion related to financial measures by approximately 45%. That is to say, DTE is not showing itself to be responsive to the Commission's guidance in this matter.

Mr. Zakem's proposal is sensible on paper, but it does not grapple with the deficiencies in DTE's benefit cost analysis, as discussed in part above. Mr. Cooper also uses formal customer complaints as example of a measure with benefits that are not quantifiable. Even in that discussion, Mr. Cooper does not consider the contributions made by the Commission staff members who work to resolve complaints at the informal stage or all the ratepayer funding of DTE expenses focused on resolving customer disputes.

b. Restricted stock

Mr. Cooper explained that DTE's LTIP includes two components, "performance shares," and "restricted stock." Restricted Stock "generally vests based on the employees' tenure," makes up approximately 30% of the stock awards to executives and directors, and is not part of the LTIP program for employees below the direct or level.[1631] He did not include the restricted stock awards in his presentation of incentive

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[1631] 7 Tr 1830.

compensation expense in Table 3 at 7 Tr 1832,[1632] testifying that "[t]he expense related to the Restricted Stock is not conditioned on any Company performance measures but rather is exclusively based on the number of shared granted at the date of grant."[1633] As noted above, Mr. Cooper testified that the purpose of the shares granted in the LTIP program is "to both motivate superior results as well as provide a means to retain key employees."[1634]

Staff recommended that the Commission exclude $5.86 million in restricted stock compensation from the revenue requirement. Ms. McMillan-Sepkoski explained Staff's recommendation, citing Exhibit S-8.3 for DTE's acknowledgement that the stock grants are considered a reward to employees for assisting the company to meet its financial performance goals.[1635] She also indicated that the Commission agreed that this expense should be excluded from the revenue requirement in Case No. U-20561.[1636]

In rebuttal, Mr. Cooper objected to considering the restricted stock grants to be based on financial measures. In addition to his contention that ratepayers should pay for the compensation associated with financial measures in the company's performance plan, he contended that once DTE makes the grant of stock, its expense is fixed and does not increase over the duration of the three-year restriction, and thus "is not dependent on either the Company's achievement of its financial objections of DTE

[1632] 7 Tr 1834.
[1633] 7 Tr 1831.
[1634] 7 Tr 1830.
[1635] 8 Tr 5264.
[1636] 8 Tr 5264, citing May 8, 2020 order, pages 202-203.

Energy's future stock price."[1637] Mr. Cooper took issue with Ms. McMillan-Sepkoski's reliance on a statement in the company's employee handbook as follows:

> Witness McMillan-Sepkoski sites the Company's LTIP employee plan description booklet included as Exhibit S-3.6 [sic] that the LTIP is "a reward to employees for assisting the Company in reaching its financial performance goals." . . . Witness McMillan-Sepkoski apparently infers from this phrase that Restricted Stock is related to financial measures and therefore, should be disallowed, consistent with traditional Commission practice regarding financial measures.[1638]

Mr. Cooper provided an illustration of his point as follows:

> The LTIP employee plan description booklet referenced by Witness McMillan-Sepkoski describes the potential benefits to employees of increases in DTE Energy's stock price on LTIP grants, that benefit has no impact on the Company's costs. This is, if an employee receives a Restricted Stock grant of 1,000 shares when DTE Energy's stock price is $100 per share and upon the elimination of the restriction DTE Energy's stock price has increased to $125 per share, the employee will have DTE Energy stock worth $125,000, but the cost to the Company will remain $100,000. Accordingly, Witness McMillan-Sepkoski's conclusion that the Restricted Stock expense is related to future financial performance is inaccurate.[1639]

Staff relies on Ms. McMillan-Sepkoski's testimony in its brief, and responds to Mr. Cooper's rebuttal testimony by arguing that restricted stock awards "are tied to value created for shareholders, sustaining profitable growth, and rewarding financial results."[1640] DTE argues in its brief that Staff is mistaken in considering the restricted stock awards as based on the company's stock performance, contending that "the stock is used as a medium to deliver the awards (like dollars, bitcoin or other methods of payment)."[1641] It relies on Mr. Cooper's testimony in asserting that Staff's

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[1637] 7 Tr 1853.
[1638] 7 Tr 1853-1854.
[1639] 7 Tr 1854.
[1640] Staff brief, 179.
[1641] DTE brief, 217.

recommendation “is also apparently based on an incorrect inference,” because even though “the LTIP employee plan descriptive booklet describes the potential benefits to employees of future increases in DTE Energy’s stock price,” the important point is that “that benefit has no impact on the Company’s costs.”[1642]

This PFD finds that DTE has not justified that it is in ratepayers’ interests to fund the restricted stock grants to executives and directors. A review of Exhibit S-8.3, pages 2-4, shows that DTE provides the awards of restricted stock—rather than some other form of compensation such as cash or bitcoin—to motivate the eligible executives and directors to create value for shareholders:

> As the energy industry changes, your role as a leader is more critical than ever to drive performance and delivery results that will contribute to our continued business success.
>
> Our Long Term Incentive Plan is designed to strengthen the link between meaningful, profitable growth for the company and financial rewards for you. The LTIP gives you an ownership stake in our company with an opportunity to build personal wealth.
>
> In return, DTE Energy (Company) expects you to focus on creating long term value for the organization in your role as a company leader.
>
> When we success, both you and the Company benefit.[1643]

The description of the program in Exhibit S-8.3 further describes the LTIP as a reward “for making decisions and taking actions that will bring the Company long term success.” It acknowledges the motivation associated with restricted stock ownership:

> When you own shares in the Company, you benefit financially when DTE Energy Company stock increases as well as when the Board authorizes a dividend. As a leader, you have the ability to make decisions that result in

[1642] DTE brief, 217; also see DTE reply, 159-160.
[1643] Exhibit S-8.3, page 2.

> meeting or exceeding both short term and long term goals. When we achieve our goals, we are more likely to see our stock price increase.[1644]

It further reinforces this objective by describing the restricted stock grant:

> This is a grant of ownership rights to DTE Energy Company stock that will vest as long as you are employed with the Company and its subsidiaries through the vesting date, which is typically three years from the date of grant. After this date, you have full ownership of the shares and can sell or hold them. Although the number of shares you receive is fixed at the grant date, the price per share can increase or decrease based on the Company's performance and the overall stock market.[1645]

In a text box under the heading "At-a-Glance," it states: Restricted stock provides greater value when the stock price increases and the higher it climbs, the larger your potential return."[1646] As Mr. Cooper acknowledges, if the stock price increases during the three-year period of restriction on sales, the executive or director further benefits from the increased stock price. The company's efforts to distinguish this compensation from any other compensation for achieving corporate financial goals are unpersuasive, and perhaps another example of the corroding influence of the company's incentive compensation programs on the credibility of the company's evidentiary presentations in rate cases.

10. PERC (Exhibit A-13, Schedule C5.16)

Mr. Davis testified that DTE proposes an extended power uprate (EPU) study to provide insight on the feasibility and cost of uprating the Fermi 2 nuclear power plant, which could provide an additional 172 MW of carbon-free baseload generating capacity.[1647] Mr. Davis explained that commercial reactors like Fermi 2 are designed

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[1644] Exhibit S-8.3, page 3.
[1645] Exhibit S-8.3, page 4.
[1646] Exhibit S-8.3, page 4.
[1647] 7 Tr 2571.

with excess capacity that allow for an EPU, but EPUs require significant modifications to major pieces of non-nuclear equipment, and a utility must secure approval from the Nuclear Regulatory Commission (NRC) to increase a reactor's maximum power level.[1648] Mr. Davis asserted that the EPU study would perform a detailed analysis of Fermi 2's existing equipment, develop cost estimates for EPU sub-projects and total EPU costs, and would conclude in 2025.[1649] He specified that DTE currently estimates that an EPU of Fermi 2 would likely range between $600 million and $1 billion, and the EPU study would allow the utility to "narrow the uncertainty in scope and cost to support a reasonable and prudent decision for a Fermi 2 EPU."[1650] Mr. Davis specified that DTE sought $4.9 million in PERC O&M expenditures for the EPU study in the calendar year 2023.[1651]

Mr. Coppola questioned the need for an EPU study and recommended rejecting the proposal and all its associated expenditures.[1652] First, Mr. Coppola explained that through discovery, DTE admitted that $4.9 million was not the total cost of the study, and the utility did not disclose its total cost.[1653] Second, he explained that even at the low end of DTE's preliminary cost estimate, i.e. $600 million, an EPU would result in an installed capacity cost of $3.4 million per MW.[1654] Mr. Coppola compared that figure to the MISO Zone 7 cost of new entry (CONE), which he asserted was only $94,000 per

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[1648] 7 Tr 2571.
[1649] 7 Tr 2572.
[1650] 7 Tr 2572.
[1651] 7 Tr 2571; also see Exhibit A-13, Schedule C5.16, page 1, line 21.
[1652] 8 Tr 4856.
[1653] 8 Tr 4855.
[1654] 8 Tr 4856.

MW.[1655] Accordingly, Mr. Coppola opined that it was not reasonable to undertake the EPU study given the vast disparity in cost between the EPU uprate and the current cost of capacity from other sources.[1656]

In rebuttal, Mr. Davis asserted that Mr. Coppola based his recommendation "on an erroneous assumption . . . that DTE Electric is conducting the EPU Study to arrive at an 'outcome.'"[1657] He explained that rather than recommending an outcome, the study provides DTE "with improved understanding of the operational considerations required to operate the Fermi 2 power plant at EPU conditions."[1658] Mr. Davis added that "[t]he value of an EPU study is to more definitively demonstrate the capability of the Fermi 2 Power Plant to safely operate at EPU conditions as well as narrow the uncertainty of scope, schedule, and expenditures associated with the work required to complete an EPU[.]" He concluded that the Commission should reject Mr. Coppola's recommendation and stated that DTE would not undertake the EPU study if the Commission adopted Mr. Coppola's recommendation.[1659]

In its initial brief, DTE repeats points from the testimony of Mr. Davis.[1660] The Attorney General responds that when DTE was questioned in discovery about the purpose of the EPU study—if not to result in actionable outcome for an economical project—that DTE replied in part that "knowledge has value[,]" "time has value[,]" and that the study was needed to better understand the opportunities and risks associated

[1655] 8 Tr 4856.
[1656] 8 Tr 4856.
[1657] 7 Tr 2584.
[1658] 7 Tr 2585.
[1659] 7 Tr 2585, 2586.
[1660] DTE brief, 180-181.

with an EPU update.[1661] The Attorney General stresses that the EPU study is not reasonable and prudent, asserting that it is “incredible” that DTE “wants to undertake a research project at a cost of nearly $5 million, which clearly cannot be economically justified, in order to simply gain some knowledge.”[1662] The Attorney General concludes that DTE “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.”[1663]

In its reply brief, DTE quotes the full discovery response referenced by the Attorney General, in which Mr. Davis explained that a refueling outage was needed to perform the EPU study, and that the potential 172 MW in extended capacity might be considered as a generation resource in a future integrated resource plan (IRP).[1664] DTE further argues that there is no merit to the argument that an “outcome” is required, and that there is only a preponderance of the evidence standard, not a higher “compelling and convincing” standard.[1665] DTE concludes that the EPU study is a reasonable and prudent approach to provide a comprehensive and fully transparent analysis of the potential to operate Fermi 2 at EPU conditions.[1666] In its reply, the Attorney General argues that the millions of dollars that DTE proposes to spend on the study cannot be justified merely by indicating what the utility could potentially learn. The Attorney

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[1661] Attorney General brief, 23; see also Exhibit AG-1.68.
[1662] Attorney General brief, 23.
[1663] Attorney General brief, 24.
[1664] DTE reply, 138-139; see also Exhibit AG-1.68.
[1665] DTE reply, 139.
[1666] DTE reply, 139.

General concludes by opining that DTE's assertions surrounding the EPU study have been "far too vague and devoid of possible customer benefits to support recovery."[1667]

This PFD agrees with the Attorney General and recommends disallowing the $4.9 million in funds for the EPU study. DTE did not rebut or address Mr. Coppola's analysis showing that an EPU—even at the low end of DTE's preliminary cost estimate—would be exceedingly uneconomical in terms of cost per MW when compared to the cost of capacity from other sources. Further, DTE appeared to offer no substantial reason to perform the study aside from desiring to obtain more specific knowledge regarding the potential EPU, which it already had reason to know was uneconomical. At best, the discovery response highlighted by DTE suggested that DTE might consider the additional Fermi 2 capacity as a potential generation resource in a future IRP. However, this PFD believes that potential use in resource planning cannot justify the $4.9 million study when DTE apparently already should have reason to believe that the EPU will be uneconomical even at the low end of its preliminary cost estimates.

11. Corporate Memberships

DAAO argues that the Commission should exclude all corporate membership dues from O&M, except for dues paid to organizations DTE is required to join. Mr. Koppel explained DAAO's concerns, citing one such membership organization's comments in this docket in support of DTE's rate increase, discovery received from DTE in Exhibit DAO-78, and a FERC docket considering whether to amend the treatment of industry association dues under the Uniform System of Accounts, in which the Attorney

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[1667] Attorney General reply, 31.

General and CUB filed comments as shown in Exhibit DAO-87.[1668] He testified that the Commission is not required to wait for FERC to act before addressing this issue.

Consistent with Ms. Uzenski's schedule C14 of Exhibit A-3, and Ms. Crozier's testimony at 7 Tr 2358, DAAO acknowledges that DTE removes certain portions of some of the dues payments to reflect lobbying and political activity. But it notes that amounts ascribed to such activities may be small relative to the total dues payments, and emphasizes that these industry organizations may not be acting in the best interests of ratepayers. DAAO also expresses frustration that DTE provided in Schedule Q1 of Exhibit A-27 a description of each membership organization, but did not provide the historical or projected dues payments.

As an alternative to excluding the costs of all non-mandatory organizations, DAAO asks the Commission to determine that these dues are presumptively unrecoverable, and to require DTE to disclose historical and projected amounts.[1669]

In her direct testimony, Ms. Crozier addressed the company's decision-making regarding these memberships:

> The Company acquires and maintains corporate memberships that help in our mission to provide safe, affordable, and reliable energy. Decisions regarding which memberships to obtain are typically made by individual business units. A list of the corporate memberships included in DTE Electric's O&M expense are shown on Exhibit A-27, Schedule Q1. As shown in this Exhibit, each membership generally falls under the auspices of one business unit.[1670]

[1668] 8 Tr 4342-4345.
[1669] DAAO brief, 99-102.
[1670] 7 Tr 2358.

And she described generally the benefits DTE ascribes to its memberships, such as benchmarking, research, best practices, and networking. Neither Ms. Crozier nor Ms. Uzenski provided rebuttal on this issue.

In its brief, DTE acknowledges that in Case No. U-20561, 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."[1671] DTE contends that Ms. Crozier's testimony, along with Schedule Q1 of Exhibit A-27, satisfy the Commission's requirement.[1672]

In Case No. U-20561, the Commission upheld the findings of the ALJ recommending against the exclusion of membership dues ABATE requested. The Commission clearly stated in its order:

> However, the Commission also adopts ABATE's request as to *the need to continually justify that such fees are truly required and/or are in the interests of ratepayers*, and *reminds the company of its continuing obligation to identify, describe, and explain projected costs* associated with membership fees in future rate cases.[1673]

As DAAO argue, DTE did not provide the dues associated with the memberships listed in Schedule Q1; it certainly did not "identify" the projected costs, let alone describe or explain them. This PFD also concludes from a review of the Commission's order that the Commission contemplated more than the generic information that DTE provided to show that the dues are "truly required" or "in the interests of ratepayers." Given the limited information on this record, this PFD cannot identify a specific rate adjustment, but it recommends that the Commission take action to ensure that adequate information

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[1671] DTE brief, 199, quoting May 8, 2020 order, Case No. U-20561, page 200.
[1672] DTE brief, 199-200.
[1673] May 8, 2020 order, page 200.

is provided in the company's future filings for the parties to evaluate the ratepayer benefits of membership, with an understanding of the cost.

G. Other Expenses

1. Tax Expense

No party took issue with DTE's projected tax expense calculations. There is thus no further dispute regarding the calculation of property tax, federal income tax, or state and local taxes. The different tax expense amounts between parties reflect different levels of projected expenditure.

2. Depreciation and Amortization

There are no disputes regarding the depreciation rates or amortization periods to apply to rate base or other amortizable expense items. To the extent the parties differ regarding depreciation or amortization expense amounts, those issues were addressed for convenience above in connection with rate base.

3. Surge Program Regulatory Asset Return

DTE recommends that any future tree trimming surge expenditures by DTE be financed through the issuance of long-term debt and equity until the time DTE can execute a securitization financing for these amounts.[1674] Mr. Lepczyk acknowledges that the Commission's May 2, 2019 Order in Case No. U-20162 provided that DTE was authorized a return on the tree trim surge regulatory asset at the short-term debt cost rate of 3.56% and in Case No. U-20561, the return on tree trim surge regulatory asset

[1674] 7 Tr 1294; Exhibit A-11, Schedule A1.1.

was calculated at that same authorized short-term debt rate.[1675] However, Mr. Lepczyk proposes a change, reasoning, in part, as follows:

> Given the temporary status, defined in Case No. U-20162, of the Tree Trim Surge regulatory asset, the Company did not pursue financing with permanent long-term debt and equity capital, but rather financed with short-term working capital including short-term debt. Thus, this was matching the financing costs with the return the Company was earning on the regulatory asset. In its order for 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 capital and receive the respective return.[1676]

Staff's projected tree trim regulatory asset return on is $2,188,000, a decrease of $4,833,000 from DTE's originally filed amount of $7,021,000 found on Exhibit A-11, Schedule A1.1, Line 6.[1677] Mr. Nichols applied the currently approved short-term debt rate of 2.73%, while DTE applied the currently approved pre-tax rate of return on permanent capital of 8.76%.[1678] Mr. Nichols notes that in Case Nos. U-20162 and U-20561, the Commission ordered the application of the short-term debt rate to be applied to the tree trim regulatory asset to calculate the return on the tree trim regulatory asset.[1679]

Mr. Nichols supports using the Commission approved short-term debt rate to calculate the return on the tree trim regulatory asset because the circumstances have not changed significantly since the Commission's May 2, 2019 Order approving the tree trim surge in Case No. U-20162, which states, in part:

[1675] 7 Tr 1294..
[1676] 7 Tr 1294-1295.
[1677] 8 Tr 5033.
[1678] 8 Tr 5033.
[1679] 8 Tr 5033.

> The Commission finds it appropriate to move forward with the surge proposal as the best way to balance these considerations, but to only authorize the first three years. Thus, the Commission approves the originally requested $95.1 million of O&M for tree trimming in the projected test period, and the first three years of spending for the surge program, being $43.3 million for 2019, $74.1 million for 2020, and $70.5 million for 2021, as a regulatory asset, with application of the short term debt cost rate adopted in this order of 3.56% rather than the pretax permanent overall cost of capital proposed by DTE Electric. This will reduce overall costs and is expected to be temporary given the company's plans to file for securitization of the tree trimming regulatory asset. Thus, the Commission finds the short-term debt rate to be more appropriate than the overall cost of capital. The company may accrue carrying costs in the regulatory asset at the short-term debt rate, and may seek recovery in a future proceeding such as a securitization or rate case using a traditional ratemaking approach.[1680]

Mr. Nichols asserts that in that case, the Commission heard various arguments regarding approval of a tree trim spending regulatory asset and ultimately approved it with the return on at the short term-debt rate, striking a balance in that case which continues to seem reasonable to Staff.[1681]

The Attorney General also opposes DTE's proposal to apply the pre-tax permanent cost of capital in calculating the return on tree trimming deferred costs, reasoning that the use of the pre-tax cost of permanent capital is counter to the Commission previously approved use of DTE's short-term debt rate.[1682] Mr. Coppola notes that Mr. Lepczyk acknowledges that in Case No. U-20162, the Commission authorized DTE to use the short-term debt rate in calculating the return on deferred tree trimming surge costs charged to the regulatory asset, but that in the recent securitization case for the first portion of the deferred tree trimming surge costs, Case No. U-21015, the Commission determined that DTE had in fact financed the surge costs

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[1680] 8 Tr 5034, Case No. U-20162, May 2, 2019 Order, p. 80. Emphasis added, citation omitted.
[1681] 8 Tr 5035; see also, Staff brief, 181-183.
[1682] 8 Tr 4883.

with permanent capital and not short-term debt, which Mr. Lepczyk interprets as a change in the Commission directive to now finance the deferred surge costs with permanent capital.[1683] Mr. Coppola disagrees, asserting that the conclusion reached by the Commission in Case No. U-21015, that DTE used permanent capital to finance the tree trimming surge costs securitized in that case, reflects the facts presented by DTE "in that particular case for those specific costs."[1684] He adds that the evidence presented by DTE and other parties in Case No. 21015 clearly showed that DTE had not used short-term debt to finance those surge costs and instead used long-term debt and equity capital.[1685] Mr. Coppola asserts that DTE has the ability to finance those surge costs with short-term debt and make a showing in the next securitization case that it has used short-term debt to finance them during the period that those costs reside in the regulatory asset. He adds that the basic premise used by the Commission in Case U-20162 that the short-term debt rate should be used in calculating the return on the deferred balance of the regulatory asset has not changed.[1686]

Mr. Coppola calculated a revised return based on the short-term debt rate of 1.74% proposed by DTE in Ex. A-14, Sch. D1, to the regulatory asset average balance of $80,147,000 to calculate a return of $1,395,000.[1687] This amount reduces both DTE's proposed return $7,021,000 and DTE's revenue deficiency by $5,626,000.[1688]

[1683] 8 Tr 4883.
[1684] 8 Tr 4884.
[1685] 8 Tr 4884.
[1686] 8 Tr 4884. See, also, Attorney General brief, 93-95.
[1687] 8 Tr 4885; Ex. AG-1.50. In its brief, Staff states that "it would also be reasonable to use the short-term debt rate from the instant case, as the Attorney General did in her calculations, in lieu of the higher short-term debt rate Staff relied upon from the previous rate case." Staff brief, 183.
[1688] 8 Tr 4884.

In rebuttal, Mr. Lepczyk disagrees with Mr. Nichols' assertion that the circumstances have not changed significantly since the Commission Order approving the tree trim surge in Case No. U-20162.

> However, subsequent to that order, in its order for 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 capital and receive the respective return.[1689]

Similarly, Mr. Lepczyk notes that Mr. Coppola stated that "[t]he conclusion reached by the Commission in Case No. U-21015 "reflects the facts presented by the Company in that particular case for those specific costs," and that the evidence presented by DTE and other parties in that case "clearly showed that the Company had not used short-term debt to finance those surge costs and instead used long-term debt and equity capital."[1690] Mr. Lepczyk disagrees.

> The Company would argue that the same circumstances that pertain to securitization Case No. U-21015 exist in the current case for the securitization of tree trim assets. It is reasonable to expect that a financing order for additional tree trim assets would result in the same conclusion and consider 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.[1691]

This PFD agrees with Staff and the Attorney General. The Commission previously authorized DTE to use the short-term debt rate in calculating the return on deferred tree trimming surge costs charged to the regulatory asset rather than the pretax permanent overall cost of capital proposed by DTE Electric, which the

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[1689] 7 Tr 1298-1299.
[1690] 7 Tr 1299.
[1691] 7 Tr 1299; see, also, DTE brief, 188, citing 7 Tr 1298-1299.

Commission found to be “more appropriate” as it would “reduce overall costs and is expected to be temporary given the company’s plans to file for securitization of the tree trimming regulatory asset.” As Staff and the Attorney General note, DTE has the ability to finance those surge costs with short-term debt and make a showing in the next securitization case that it has used short-term debt to finance them during the period that those costs reside in the regulatory asset. Accordingly, this PFD recommends that the Commission authorize a return of $1,395,000, based on the short-term debt rate of 1.74% as proposed by Staff and the Attorney General.[1692]

4. AFUDC

There was also no dispute between the parties regarding the calculation of AFUDC. The differences are driven by different projected capital expenses.

H. Net Operating Income Summary

Based on the recommendations above, this PFD estimates an adjusted net operating income of $1,002,341,000, as shown in Appendix C.

VIII.

REVENUE DEFICIENCY

Based on the findings and recommendations in sections IV. through VII above, this PFD recommends a revenue deficiency of $145,680,000 as shown in Appendix A.

[1692] Exhibit AG-1.50. As indicated, Staff agrees that the short-term debt rate proposed by the Attorney General is reasonable.

IX.

OTHER REVENUE-RELATED ITEMS

A. Pilot Programs

DTE proposed several pilot projects in this case. Some parties also proposed pilot projects. Certain generation and distribution system projects that fall within the definition of pilot projects were addressed above in the rate base discussion, including the company's green hydrogen and slocum battery pilot projects discussed in section V.A above, and the strategic and service undergrounding and NWA pilot programs discussed in section V.B above. This section discusses the remaining pilots.

1. Battery Storage—C&I

For the company, Mr. Farrell testified that DTE proposes a behind-the-meter (BTM) battery energy storage system (BESS) pilot for one or two C&I customers.[1693] He explained that the pilot will test the ability to achieve peak demand shaving or time shifting during demand response events.[1694] Mr. Farrell specified that the pilot would encompass battery systems with a capacity between 500 kW to 2 MWh at each of two sites.[1695] Under the program, the utility will control the BESS when calling a dispatch event, but the customer will otherwise be able to control and utilize the BESS.[1696] Mr. Farrell stated that the pilot will select C&I customers suited for the pilot from tariff groups

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[1693] 7 Tr 1684.
[1694] 7 Tr 1684.
[1695] 7 Tr 1686.
[1696] 7 Tr 1685.

D4, D6.2, or D11 based upon their peak load profiles, outdoor space availability, and operational capabilities.[1697]

Regarding implementation, Mr. Farrell testified that the utility completed a RFI in 2021, subsequently conducted an RFP, and is finalizing the selection of a specific equipment provider.[1698] He stated that the pilot will be evaluated by measuring load reduction during events called by the utility, as well as by evaluating the customer's peak load reduction and utilization of the BESS.[1699] Mr. Farrell explained that the pilot will provide information on battery storage, on how storage can be paired with DR programs, and to help the utility develop appropriate tariffs and compensation models as contemplated by the Commission's order in case U-21032.[1700] The utility forecasts $2.8 million in capital expenditures for the C&I Battery Pilot.[1701]

Mr. Matthews expressed that while Staff supports this pilot concept, the proposal was lacking in specific details about its operation.[1702] He stated that DTE did not detail several critical aspects of the program that affect its value, including participation costs, event notification, and battery utilization outside of demand events.[1703] Mr. Matthews recommended that the Commission disallow expenses for the pilot program, explaining "[g]iven the details of the pilot that have not been assessed, it is more reasonable for

[1697] 7 Tr 1685.
[1698] 7 Tr 1686-1687.
[1699] 7 Tr 1687.
[1700] 7 Tr 1688.
[1701] 7 Tr 1687; see also Exhibit A-12, Schedule B5.6, p 2, line 15.
[1702] 8 Tr 5383.
[1703] 8 Tr 5383.

the company to request approval for funding to be included in rates after those programmatic decisions have been made."[1704]

In rebuttal, Mr. Farrell asserted that the C&I Battery Pilot is "sufficiently developed to launch a successful pilot program."[1705] He explained that since the instant case was filed, DTE completed the RFI and RFP process, had selected a final battery provider, and executed the contract in the first quarter of 2022 with an investment of $3.1 million.[1706] Given the company's forward progress, Mr. Farrell opined that the Commission should approve the bridge period expenditures of $1,356,847 and the forecasted test period expenditures of $1,514,933.[1707]

In their initial briefs, DTE maintains that the pilot is sufficiently developed, while Staff asserts that the company neglected to address Staff's specific concerns about the lack of programmatic details.[1708] In its reply brief, DTE repeats that the pilot is sufficiently developed adding that "[i]t is unclear what Staff has in mind, or why Staff may consider it sufficient to disallow the pilot, particularly after supporting the idea and acknowledging the Company's progress."[1709]

This PFD recommends disallowing the C&I Battery Pilot costs, at least currently. DTE demonstrated that it is moving forward with the pilot, but the utility's rebuttal testimony and briefing strangely neglected to address Staff's specific concerns about the lack of key details about the structure of the pilot program. While DTE apparently believes it is "unclear" what information Staff sought, the testimony from Mr. Matthews

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[1704] 8 Tr 5383.
[1705] 7 Tr 1703.
[1706] 7 Tr 1703.
[1707] 7 Tr 1703.
[1708] DTE brief, 118; Staff brief, 95-96.
[1709] DTE reply, 90-91. Notably, Staff did not further address the C&I battery pilot in in its reply brief.

was unambiguous regarding the topics that Staff believed needed further development to evaluate the overall value of the pilot proposal.[1710] Accordingly, this PFD agrees with Staff that it is reasonable for DTE to request approval for funding to be included in rates after the details of the pilot are further developed and clarified.

2. Residential Generator

Mr. Farrell initially identified this pilot as one that the company is evaluating through a Request for Information (RFI) with potential impact on peak demand reduction. Mr. Farrell explained:

> The Company plans to conduct a residential customer-owned natural gas generator pilot. The pilot will leverage a third-party service provider's platform utilizing telemetry to shift customers' electric load to the customers' generator in real-time during peak events. Initial plans indicate that the customers will receive an incentive for their participation in the program.[1711]

Mr. Doherty explained Staff's position that the pilot is insufficiently developed to be approved. He also testified that Consumers Energy has a similar pilot that could offer opportunities for shared learnings that would influence the scope of a future DTE pilot.[1712] In rebuttal, Mr. Farrell testified:

> While I understand Witness Doherty's concern that the pilot is still in the exploratory phase, much progress has been made on the development of the pilot since the first of the year that could possibly ease concerns and show the pilot is moving forward as planned.

He explained that since DTE issued an FRI, it received three bids and selected Generac Services for implementation of the pilot. He described the pilot further:

> As of the beginning of 2022 there are 81,000 Generac residential home standby generators in DTE's service territory, 13,000 of which are

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[1710] See 8 Tr 5383.
[1711] 7 Tr 1689.
[1712] 8 Tr 5528-5529.

> operational and ready for dispatch according to Generac Grid Services. The pilot will target 100-200 customers. Final contract execution is underway and targeted for completion by the third quarter of this year. The pilot will run for at least two full summer seasons. From benchmarking efforts and conversations with Generac, the Company expects 5 kW load reduction per participating customer. The Company also plans to speak with Consumers Energy about their pilot to possibly apply some of their learnings to the design of the Company's residential generator pilot.[1713]

On this basis, he recommended that the proposed expenditures be approved.

In its brief, Staff argues that although the Company's rebuttal does provide useful information on the proposed residential generator pilot and shows commitment from the Company to move forward, it does not address all of Staff's concerns.[1714]

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

3. Residential Window A/C

Mr. Farrell testified that DTE proposes a residential, customer-owned window air conditioning pilot that would use a third-party service provider's DR platform to cycle the A/C units during peak events.[1715] He explained that the utility was exploring the possibility of providing customers with a company-owned hardware solution that would transform any window A/C unit into a Wi-Fi-enabled DR resource to broaden the eligible

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[1713] 7 Tr 1702.
[1714] Staff brief, 94.
[1715] 7 Tr 1691.

pool of customers.[1716] According to Mr. Farrell, the company estimated that approximately 25% of its customers have a window A/C unit, and the pilot would test customer receptiveness to the program, test different incentive offerings, and measure overall demand reduction during peak events.[1717] He explained that the utility was going to issue a RFI to better understand the opportunities for a DR pilot involving residential A/C units.[1718] Mr. Farrell testified that the utility planned to invest $0.70 million in capital expenditures for the pilot.[1719]

Mr. Doherty testified that Staff does not oppose this pilot in concept, but Staff "would like a better understanding of the potential for demand savings, proposed control technologies, and incentive structure prior to approving the inclusion of costs for this pilot into rates."[1720] Thus, Mr. Doherty recommended disallowing the proposed capital expenditures opining that the residential window AC pilot was in an "exploratory phase" and was insufficiently developed to be included in rates.[1721]

The company provided no pertinent rebuttal testimony. In the briefing, the company does not provide further details, and Staff reiterates its request for a disallowance based upon the pilot's lack of development at this stage.[1722]

This PFD agrees with Staff and recommends disallowing the company's proposed capital expenditures for the residential AC pilot because the pilot proposal is not sufficiently developed for inclusion in rates at this point.

[1716] 7 Tr 1691.
[1717] 7 Tr 1692.
[1718] 7 Tr 1692.
[1719] 7 Tr 1693; see also Exhibit A-12, Schedule B5.6, p 1, line 3, columns (c) through (f).
[1720] 8 Tr 5528.
[1721] 8 Tr 5528.
[1722] Staff brief, 93.

4. EV Pilots (Charging Forward)

In its application, DTE proposed the extension or modification of preexisting elements of its Charging Forward pilot program to support EVs, including Customer Education and Outreach (E&O), Residential Smart Charger Support (Residential Rebates), Bring Your Own Charger (BYOC), EV-Ready Builder Rebates, and Charging Infrastructure Enablement (Make-Ready Rebates).[1723] Additionally, DTE proposed the introduction of new elements to the program including both Residential and Commercial Charging as a Service (CaaS), Charging Hubs, Transit Batteries, Transportation Network Company (TNC) Driver Rebates, Income-Eligible Rebates, and an Emerging Technology Fund.[1724] Mr. Burns testified that the purpose of these new elements is to help alleviate barriers to EV adoption, increase equitable access to EVs, efficiently integrate EV load into the grid, test new technologies, and support the Michigan's EV-related policy goals.[1725] For the most part, the parties generally supported the continuation of pre-existing elements of the Charging Forward program and also largely supported its expansion through various new pilot programs. Concerns raised by the parties about various elements of Charging Forward are addressed in the subsections below.[1726]

[1723] 7 Tr 2413.
[1724] 7 Tr 2413-2414.
[1725] 7 Tr 2424.
[1726] No party contested the company's proposals for the continuation and funding of the BYOC pilot, EV-Ready Builder Rebates pilot, the eFleets Program, or the administration and staffing costs of the Charging Forward expansion. Because these items are not in dispute, this PFD recommends their approval as described by the company.

a. Customer E&O

Mr. Burns testified that the company seeks to expand customer E&O by ramping up in-person EV experiences, which it has not previously been able to do because of the COVID-19 pandemic.[1727] The company also seeks to develop an enterprise-wide rate tool to educate customers about the best TOU rate to meet their charging needs; additionally, the company also seeks to improve its virtual EV showroom tool.[1728] The company requests just under $1.5 million for E&O, encompassing $0.95 million in O&M and $0.50 million as a regulatory asset.[1729]

Mr. Freeman testified that Staff supports the company's request adding the caveat that he recommends that the company seek out third-party funding from government or industry trade groups before spending ratepayer dollars on E&O.[1730] Testifying on behalf of ChargePoint, Mr. Deal supported the company's expanded E&O efforts suggesting that all E&O materials should be vendor neutral and should not favor any specific product lest the utility's outreach distort the market.[1731] In briefing, the parties repeat the points developed in their testimony.[1732]

This PFD recommends approving the company's request for E&O approval, with added encouragement that the utility should seek third-party funding for E&O if available, and that E&O materials should remain vendor neutral.

[1727] 7 Tr 2427.
[1728] 7 Tr 2427-2428.
[1729] 7 Tr 2428; see also Exhibit A-12, Schedule B5.9, p 4, lines 9 and 16.
[1730] 8 Tr 5539.
[1731] 8 Tr 4595.
[1732] DTE brief, 147; Staff brief, 206; ChargePoint Brief, 11-12.

b. Residential Rebates

Mr. Burns stated that DTE proposes to continue to offer the existing $500 residential charger rebate but to remove the list of qualified chargers to allow customers to install a Level 2 charger of their own choice.[1733] He explained that this would allow customers to choose less expensive chargers, and the company can compensate for any loss of data from chargers that would have otherwise been network capable by using AMI, advanced analytics, and EV telematics.[1734] Mr. Burns explained that the BYOC program would continue to be offered in parallel for customers that were uncomfortable enrolling in a TOU rate or paying for the installation of a second meter.[1735] The company sought $0.4 million deferred as a regulatory asset to support rebates for up to 800 customers.[1736]

Mr. Freeman testified that Staff supports the company's proposal to continue the rebates and eliminate the list of qualified chargers.[1737]

Mr. Deal supported the company's proposal in part, but he urged the company to continue to require network capability for any charger installed under the rebate program.[1738] He explained that requiring networked chargers would future-proof investment in EV infrastructure and would still provide many benefits despite the small scale of the program.[1739] Mr. Deal also proposed that the company should require

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[1733] 7 Tr 2430.
[1734] 7 Tr 2431, 2432.
[1735] 7 Tr 2432.
[1736] 7 Tr 2430; see also Exhibit A-12, Schedule B5.9, p 4, line 20.
[1737] 8 Tr 5540.
[1738] 8 Tr 4570-4572.
[1739] 8 Tr 4572-4573.

ENERGY STAR and UL certification for all chargers installed under the rebate program to ensure safety and to meet energy efficiency standards when idle.[1740]

In rebuttal, Mr. Burns stated that the company agreed that it would require the chargers to be UL and ENERGY STAR certified.[1741] But the company rejected that idea that it should require the chargers to be networked for three reasons. First, the cost of networked chargers is greater, which discourages adoption. Second, the load management and data collection of networked chargers can also be obtained through vehicle telematics as the company has demonstrated through its Smart Charge pilot. Third, customers participating in Residential CaaS and Residential Rebates could opt for a NEMA 14-50 outlet, which the company considers the same as a non-network charger.[1742]

In rebuttal, Mr. Revere asserted that Staff does not support the request to require that chargers be network capable because several EVs are themselves network capable, and therefore the proposed networking requirement for chargers may not be necessary.[1743] Mr. Revere also critiqued the request to require chargers to be ENERGY STAR certified because it was unclear whether the benefit of nominal energy savings would be offset by the potential loss of qualifying chargers.[1744]

In briefing, the parties repeat the positions that they developed through their testimony.[1745]

[1740] 8 Tr 4574.
[1741] 7 Tr 2512.
[1742] 7 Tr 2503.
[1743] 8 Tr 5153.
[1744] 8 Tr 5153.
[1745] DTE brief, 150; Staff brief, 207; ChargePoint brief, 2; DTE reply brief, 119.

This PFD recommends allowing the company to continue offering Residential Rebates and to drop the list of qualified chargers to thereby allow customers to select a charger of their choice. For the reasons stated by the company and Staff, this PFD rejects the recommendation to require chargers to be network capable to receive the rebate in this pilot program.

c. Residential CaaS

Mr. Burns stated that DTE requests approximately $2.4 million ($2.29 million in capital expenditures and $61,000 in O&M) to offer turnkey installation and financing for up to 1,100 customers interested in a Level 2 charger for their single-family homes.[1746] He explained that the utility would contract with licensed electricians to install a 240V outlet and, if the customer desires, an EV charger.[1747] The customer would thereafter pay a monthly fee on their electric bill for a period of 10 years.[1748] Mr. Burns explained that this program would alleviate the up-front sticker shock of installing an EV charger, and he testified that the program was designed to be participant-funded and rate base neutral.[1749]

Mr. Freeman asserted that Staff opposes this proposal as designed.[1750] He acknowledged that the program is conceptually attractive, but he contended that it lacks key details such as how electricians will be selected and vetted for inclusion (i.e. how to ensure selection is based on merit), how long an electrician's inclusion in the program

[1746] 7 Tr 2433; see also Exhibit A-12, Schedule B5.9, p 4, lines 5 and 12.
[1747] 7 Tr 2433.
[1748] 7 Tr 2433.
[1749] 7 Tr 2434.
[1750] 8 Tr 5541.

will last, and how much each electrician will charge for the installation.[1751] He opined that without that information, there are too many unknowns to support the proposal.

On behalf of MNSC and CUB, Mr. Jester was generally supportive of the proposal but recommended that participants be required to choose between a TOU tariff or inclusion in the company's BYOC program to ensure that charging times are managed to reduce strain on the grid.[1752]

In rebuttal, the Mr. Burns addressed Staff's concerns by explaining that DTE intends to use its existing supply chain request for proposal (RFP) approach with targeted follow-ups to select appropriate electricians.[1753] Mr. Burns explained that the RFP process will be annually refreshed and will require electricians to disclose information including licensing and insurance, past experience with EV charger installation, number of employees and their skill level, and pricing information for various installation factors.[1754] He added that customers' bills would necessarily vary based upon their unique site configuration, the customer would have to approve the fee before installation, and each customer would be asked to complete a post-installation survey to gain feedback on the electrician.[1755]

Mr. Burns also explained that the company disagreed with Mr. Jester's proposal to require participants to select either a TOU tariff or inclusion in the BYOC program. Mr. Burns stated that the DTE was not phasing out its $500 Residential Rebate program

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[1751] 8 Tr 5541.
[1752] 8 Tr 3827.
[1753] 7 Tr 2510.
[1754] 7 Tr 2511.
[1755] 7 Tr 2511.

as witness Jester cited in his reasoning to support his proposal.[1756] Mr. Burns added that off-peak charging incentives will be heavily promoted to Residential CaaS participants, and a key insight that the utility will glean from this program is the proportion of customers that decline such incentives and their reasons for doing so.[1757]

In initial briefing, DTE asserts that the details provided in its rebuttal testimony should allay Staff's concerns about the pilot,[1758] and Staff agrees stating that it now supports approval of the pilot.[1759] MNSC reiterates its support for a TOU rate requirement.[1760] In its reply brief, DTE also repeats its position.[1761] In its reply brief, MSNC clarifies that its TOU rate proposal is not based upon the incorrect premise that DTE is phasing out the residential rebate program, but rather is premised on the view that the utility must maximize ratepayer benefits of EV charging by promoting off peak charging for EVs.[1762]

This PFD recommends approving the program for Residential CaaS as described by the company. The company's rebuttal testimony adequately addressed Staff's concerns about the selection of electricians. Additionally, this PFD declines to adopt Mr. Jester's recommendation to mandate a TOU tariff or inclusion in the BYOC program for the reasons stated by DTE, i.e. participants will be offered off-peak charging incentives, and the utility will gain insight from customers that decline the incentives.

[1756] 7 Tr 2512.
[1757] 7 Tr 2512.
[1758] DTE brief, 149.
[1759] Staff brief, 209.
[1760] MNSC brief, 149-150.
[1761] DTE reply, 118-119.
[1762] MSNC reply, 13.

d. Make-Ready Rebates

Mr. Burns testified that the company proposed continuing and modifying its Make-Ready Rebates to incentivize commercial customers to install Level 2 chargers and DCFCs. He testified that if approved, the company would continue to offer the same rebate amounts for DCFCs, but for Level 2 chargers DTE proposed to decrease the rebate from $2,500 per port to $2,000 per port, which he characterized as being "more in-line" with the cost of installation.[1763] Mr. Burns explained that the utility sought approximately $3.9 million for Make-Ready Rebates ($1.4 million in capital expenditures and $2.458 million as a regulatory asset), which could support installation of up to 250 Level 2 ports and 50 DCFCs.[1764]

Mr. Freeman stated that Staff supports the company's proposal for Make-Ready Rebates as proposed.[1765]

Mr. Jester testified that the Make-Ready Rebate program should be modified to require that the installed infrastructure can support up to 350 kW DCFCs and DCFC rebates should require that the DCFC itself support at least a 150 kW charging rate.[1766] Mr. Jester asserted that the Federal Highway Administration's (FHA) guidance suggested that 150 kW be the minimum per-port charging rate, and many new EV models support charging at that rate as well.[1767]

On behalf of EVgo, Ms. Dumit supported continuing and expanding the Make-Ready Rebates Program; in fact, she proposed increasing program funding to $5.85

[1763] 7 Tr 2441.
[1764] 7 Tr 2439; see also Exhibit A-12, Schedule B5.9, p 4, lines 2 and 17.
[1765] 8 Tr 5541.
[1766] 8 Tr 3822.
[1767] 8 Tr 3823.

million.[1768] Ms. Dumit suggested that part of this increase could be achieved by redirecting the $1.2 million proposed for Commercial CaaS and instead allocating it to the Make-Ready Rebate Program.[1769] According to Ms. Dumit, this funding increase is needed to better address the growing demand for DCFCs in the utility's territory.[1770] Additionally, Ms. Dumit proposed that DTE should publish a point-based scoring rubric so that program applicants are aware of the characteristics by which their application will be judged.[1771] Notably, in rebuttal, Mr. Deal echoed EVgo's suggestion that DTE should publish a scoring rubric for the Make-Ready Program.[1772]

Testifying on behalf of MEIBC and IEI, Dr. Sherman supported the proposal but asserted that the Commission should require the company to set a charger uptime requirement of 97% over a 12-month period, create reporting requirements for uptime using a standardized formula, and implement status reporting so that customers can determine when charging services are available.[1773] Dr. Sherman also opined that the Commission or DTE should consider requiring site hosts to have monitoring and maintenance agreements in place with EV service equipment suppliers to ensure regular maintenance and reliability.[1774]

In rebuttal, Mr. Burns rejected Mr. Jester's suggestion that the charging infrastructure should be required to support 350 kW chargers arguing that such

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[1768] 8 Tr 4682.
[1769] 8 Tr 4682-4683.
[1770] 8 Tr 4682.
[1771] 8 Tr 4684.
[1772] 8 Tr 4612-4613.
[1773] 8 Tr 4416-4417.
[1774] 8 Tr 4390-4391.

extensive futureproofing could create excess capacity that may never be used.[1775] Mr. Burns also disagreed with Mr. Jester's recommendation to require that all chargers support the 150 kW charging rate. He explained that there were instances where that rate was either cost-prohibitive or poorly matched for a specific site.[1776] Mr. Burns also disagreed with Dr. Sherman's proposal to create an uptime commitment with a standard reporting formula. He explained that the federal National Electric Vehicle Infrastructure (NEVI) program was expected to release its own uptime requirements, which may be different or use a different formula than the one presented by Dr. Sherman.[1777] Further, Mr. Burns asserted that it was unclear how any uptime commitment could be enforced because several parties (manufacturers, network providers, owner-operators), not just DTE, claim some interest in the charging infrastructure.[1778] Mr. Burns also rejected Dr. Sherman's proposal to require that chargers receiving incentives should be required to make charging port status information available through websites or apps. He explained that DTE did not know how such a requirement could be enforced, and that in any event, site hosts and network providers have a natural incentive to make such information available.[1779] Mr. Burns agreed to Ms. Dumit's suggestion regarding a scoring rubric, and the utility committed to publishing a scoring rubric for potential site hosts within 30 days if the Make-Ready Rebates are approved.[1780]

In Staff's rebuttal, Mr. Revere took issue with Ms. Dumit's testimony that the program would not support enough new DCFC installations. Mr. Revere testified that

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[1775] 7 Tr 2519.
[1776] 7 Tr 2519.
[1777] 7 Tr 2520.
[1778] 7 Tr 2520-2521.
[1779] 7 Tr 2521.
[1780] 7 Tr 2521-2522.

the purpose of the pilot was not to provide rebates for every party interested in installing a DCFC, but rather to form a “skeleton network” to jumpstart the charging market and reduce range anxiety.[1781]

In rebuttal, Mr. Deal also raised concerns regarding MEIBC and IEI’s proposal to require 97% uptime for chargers. Mr. Deal stated that while ChargePoint generally supports an uptime requirement, the suggested uptime target was not developed in an evidence-based manner and may impose an arbitrary requirement.[1782] Mr. Deal opined that any uptime requirement should be developed in a deliberate, evidence-based way, possibly through a Commission-directed stakeholder workshop.[1783] Mr. Deal also addressed Dr. Sherman’s proposal to require that the status of charging ports should be made available to customers through online portals or apps. He opined that this recommendation was unnecessary because charging port statuses are already publicly provided on the non-proprietary apps of ChargePoint and several other EV charging networks.[1784] Mr. Deal also expressed concerns about Dr. Sherman’s proposal to require site owners to contract with EV service equipment suppliers for regular maintenance and upkeep. He suggested that such a decision should be left to the site owner, such a requirement could be redundant in the face of possible uptime requirements, and requiring maintenance contracts directly with EV service equipment suppliers could cut out other entities that provide those services.[1785] Finally, Mr. Deal opined that there should not be a minimum requirement of 150 kW charging rate as

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[1781] 8 Tr 5154.
[1782] 8 Tr 4613, 4614.
[1783] 8 Tr 4614.
[1784] 8 Tr 4616-4617.
[1785] 8 Tr 4615-4616.

suggested by Mr. Jester because EV charging needs can vary; instead, if the Commission was determined to set a minimum, then he suggested it should be 50 kW.[1786]

In rebuttal, Ms. Dumit also took issue with the uptime requirement proposed by Dr. Sherman. Ms. Dumit objected to adopting a reliability standard because doing so could potentially create inconsistency with federal guidelines that may be released in the near future by the FHA's NEVI program.[1787] If the Commission were to decide to implement an uptime requirement, Ms. Dumit opined that Dr. Sherman's reliability metric was reasonable, but she offered some ideas for modifications.[1788] Ms. Dumit also addressed Dr. Sherman's proposal to require that charging port status data should be publicly available on the internet. Ms. Dumit explained that EVgo and many other third parties already provide that information on public-facing apps; she added that PlugShare, a website and app, already provides such information to the public.[1789] Ms. Dumit also took issue with Mr. Jester's suggestion that the charging infrastructure should be required to support up to 350 kW chargers and have chargers with a minimum capacity of 150 kW. Ms. Dumit did not recommend setting any minimum capacity; instead, she recommended a scoring rubric for the Make-Ready Rebates that would assign higher scores to higher capacity chargers.[1790] But if the Commission intended to set a minimum capacity, Ms. Dumit recommended 100 kW rather than 150

[1786] 8 Tr 4617, 4618.
[1787] 8 Tr 4705, 4706.
[1788] 8 Tr 4706.
[1789] 8 Tr 4708.
[1790] 8 Tr 4710.

kW.[1791] Ms. Dumit also expressed concern about futureproofing for 350 kW charging capacity asserting that it made installation more expensive.[1792]

In initial briefing, the parties generally reiterate the positions staked out in their respective testimonies.[1793] However, MEIBC/IEI noted that the FHA's anticipated NEVI notice of proposed rulemaking was recently released which recommends a 97% uptime requirement, and MEIBC/IEI opines that the requirement is "highly unlikely" to be changed when the final rule is eventually adopted.[1794]

In its reply brief, DTE asserts that it maintains its position on this issue because the NEVI notice of proposed rulemaking is outside the scope of the record upon which the Commission must base its decision, and "what MEIBC/IEI might consider 'likely' is speculation that cannot support a decision."[1795]

In its reply, MEIBC/IEI argues that the Commission should adopt the uptime requirement it proposed because any standard adopted now by the Commission could later be amended if it was inconsistent with the finalized NEVI standard.[1796] MEIBC/IEI also argues that if the Commission accepted its uptime reliability standard, it should reject suggestions from EVgo to included "excluded minutes" exceptions in its uptime formula for force majeure events and design errors and latent defects.[1797] MEIBC/IEI

[1791] 8 Tr 4711.
[1792] 8 Tr 4710.
[1793] DTE brief 151-152; Staff brief, 204; MNSC brief, 148; EVgo brief, 2-8; ChargePoint brief, 5-7; MEIBC/IEI brief, 10.
[1794] MEIBC/IEI brief, 16-17.
[1795] DTE reply, 122.
[1796] MEIBC/IEI reply, 2.
[1797] MEIBC/IEI reply, 3.

explains that those proposed exceptions were not subjected to scrutiny and insufficiently defined to be included in the standard.[1798]

In its reply, MNSC reiterated support for MEIBC/IEI's uptime requirement arguing that the proposed 97% uptime standard matched the now-released proposed NEVI standard.[1799] MNSC also opined that DTE's statement that it was not aware how an uptime standard could be enforced was not credible given that the utility's existing service agreement contains twenty-five terms and conditions which could be amended to include an enforceable uptime requirement.[1800]

This PFD agrees with Staff and recommends approving the Make-Ready Rebate Program as described by the company. Specifically, this PFD declines to adopt the 350 kW minimum infrastructure capacity requirement and 150 kW minimum charging rate requirement suggested by Mr. Jester for the reasons stated by DTE and by Mr. Deal and Ms. Dumit.

This PFD also declines to adopt Ms. Dumit's suggestion to scrap the company's proposed Commercial CaaS pilot and reallocate all funds proposed for that pilot to the Make-Ready Rebate program. The Commercial CaaS pilot is targeted toward communities that have not realized significant participation in the Charging Forward family of EV programs, and the Commercial CaaS is a reasonable way to achieve more equitable access to EVs for the reasons discussed in the pertinent section of this PFD.

Further, this PFD declines—at least at this time—to adopt the 97% uptime requirement and the specific uptime reporting formula proposed by Dr. Sherman. While

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[1798] MEIBC/IEI reply, 3-4.
[1799] MNSC reply, 14.
[1800] MNSC reply, 14-15.

the FHA's NEVI program recently released a notice of proposed rulemaking with a 97% uptime requirement, that proposed rule has not yet been finalized. In testimony for DTE, Mr. Burns recommended aligning with NEVI requirements and allowing network providers to build their reporting capabilities before considering any such requirement for the Charging Forward program.[1801] In contrast, MEIBC/IEI and MNSC assert that the standard could be adopted and implemented now arguing that the proposed NEVI standard is unlikely to be changed, and even if it is changed before being finalized, the Commission could amend the standard to match the final NEVI requirements later if it so desired. While that is one possible approach, for the sake of simplicity this PFD recommends considering the adoption of the NEVI uptime standard, and its associated reporting requirements, only after it has been published as a final rule. While the intervenors cited generalized concerns about charger uptime, MEIBC/IEI indicated that there "was not a specific concern relating to the reliability of charging infrastructure in DTE's service territory[.]"[1802] Accordingly, this PFD perceives no urgent need to immediately adopt an uptime requirement and instead recommends considering the adoption of the federal NEVI uptime standard only after it has been finalized.

This PFD also declines to adopt Dr. Sherman's suggestion to require that charging stations funded by the Make-Ready Program should implement status reporting so that customers can determine when charging services are available. To be sure, such a requirement makes sense to enhance the customer experience. However, it appears from the testimony of other parties—most notably Mr. Deal and Ms. Dumit—

[1801] 7 Tr 2521.
[1802] MEIBC/IEI brief, 11.

that such information may already be disseminated through websites and apps publicly available for consumers to use.

Finally, this PFD declines to adopt Dr. Sherman's suggestion to require site owners to contract with EV service equipment suppliers for regular maintenance and upkeep. This PFD views such decisions as being best left to the discretion of the site owner, and requiring contracts directly with EV service equipment suppliers could potentially exclude other entities that may provide similar services.

e. Charging Hubs

Mr. Burns stated that DTE proposed to "build, own, operate, and maintain sites with several high-powered direct current fast chargers (DCFC) at appropriate sites when certain buildout criteria are met to justify the investment."[1803] He explained that the proposed charging hubs would be primarily designed to serve medium-duty (MD) and heavy-duty (HD) fleet EVs, while also being able to accommodate light-duty passenger vehicles. He asserted that such Charging Hubs were needed to encourage commercial customers to pilot fleet electrification at a low cost.

Mr. Burns opined that it was appropriate for DTE to own and operate charging hubs because the utility "is uniquely suited to site Charging Hubs where there is both sufficient power supply and customer demand," explaining that the utility could identify ideal locations on its grid to construct such hubs.[1804] Mr. Burns testified that the rate to use the charging hub "would be structured with a volumetric charge and session fee to reflect the cost that the company incurs to serve the Charging Hub and a per session

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[1803] 7 Tr 2442.
[1804] 7 Tr 2443.

charge to offset a portion of the initial capital outlay to build it."[1805] Per Mr. Burns, DTE was requesting approximately $2.8 million ($2.8 million in capital expenditures and $40,000 in O&M) to construct up to two Charging Hubs provided that six build-out criteria were met for a proposed Charging Hub site.[1806]

Mr. Freeman voiced Staff's support for the utility's Charging Hubs proposal,[1807] as did ITC, noting that it would be collaborating with DTE on the hubs.[1808] But other parties raised serious concerns about the proposal. Mr. Deal explained:

> ChargePoint believes that EV Charging Hubs owned and operated by monopoly utilities are not a sustainable long-term solution to support fleet charging. Instead, utilities should develop programs that support the deployment of MD and HD fleet charging at a lower cost to ratepayers, such as make-ready and EVSE incentives. Incentives can support the electrification of fleets and have proven to be an effective tool for DTE to support the deployment of DCFC charging infrastructure.[1809]

Mr. Deal expressed concern that utility-owned Charging Hubs were not in the best interest of ratepayers because of the additional costs they would impose.[1810] He also expressed concern that utility-owned Charging Hubs could potentially charge non-competitive rates or otherwise discourage the development of the private charging industry.[1811] Mr. Deal believed that private parties could adequately site Charging Hubs, and their efforts to do so would be facilitated if DTE were required to provide updated capacity maps that included additional information like load serving capacity at

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[1805] 7 Tr 2445.
[1806] 7 Tr 2444; see also Exhibit A-12, Schedule B5.9, p 4, lines 4 and 11.
[1807] 8 Tr 5542.
[1808] 8 Tr 4625-4626.
[1809] 8 Tr 4584.
[1810] 8 Tr 4586.
[1811] 8 Tr 4586.

substation and circuit levels, feeder identification and characteristics, substation source, voltage information, and other “last mile” grid information.[1812]

Ms. Dumit asserted that utility ownership of Charging Hubs would be “far more costly” than providing third-party rebates; she testified that in response to discovery, DTE estimated that it would cost $760,000 for the company to provide rebates to incentivize the third-party development of hubs in comparison to the $2.8 million requested by the company.[1813] Like Mr. Deal, Ms. Dumit also expressed that third-parties could adequately site Charging Hubs if DTE were required to provide regularly updated capacity maps with additional relevant grid information.[1814] Ms. Dumit recommended that DTE should instead be directed to explore program models that complement—rather than compete with—the private sector, for example using an RFP process to solicit third-party bids for development of Charging Hubs.[1815]

Testifying on behalf of GLREA, Mr. Richter objected to DTE’s Charging Hub proposal arguing that private enterprises can site Charging Hubs, and that the private charging industry should not have to compete against a regulated utility that does not need to generate a profit from Charging Hubs.[1816]

Mr. Jester was generally supportive of the Charging Hub proposal, but he also questioned the Company’s claim that it was uniquely positioned to site hubs given DTE’s unwillingness or inability to identify any potential site during discovery.[1817] He suggested that the Commission should direct DTE to provide online charging capacity

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[1812] 8 Tr 4588-4589.
[1813] 8 Tr 4691; see exhibit EVG-4 (CD-4) (DTE Response to Data Request EVGDE-1.3).
[1814] 8 Tr 4692-4693.
[1815] 8 Tr 4695-4696.
[1816] 8 Tr 3249.
[1817] 8 Tr 3828.

maps to facilitate third-party development of charging hubs, and he proposed that the Commission should clarify that the Company was expected to facilitate the development of privately owned hubs by providing the appropriate grid information.[1818]

Mr. Burns responded to criticisms of DTE's Charging Hub proposal first by stating that it sought critical learnings that could best be achieved through full ownership and control of the Charging Hubs.[1819] For this reason, he disagreed with Ms. Dumit's conclusion that the same effect could be achieved with $760,000 of incentives for private development.[1820] Second, he asserted that despite piloting Make-Ready Rebates with fleet incentives for three years, no third-party ever approached the company to deploy charging infrastructure for fleet MD and HD EVs.[1821] Third, he distinguished the RFP example provided by Ms. Dumit explaining that it focused only on light-duty EVs.[1822] Fourth, he asserted that if DTE did not get approval for the hubs, then it would lose both the ability to leverage certain federal funds and the ability to supplement its eFleets Advisory Service with company-owned Charging Hubs.[1823]

Ms. Pfeuffer also rebuffed the idea of providing updated capacity maps with greater detail asserting that load was dynamic; the proposed capacity maps could potentially mislead developers, and updating capacity maps regularly would ultimately add to costs borne by customers.[1824] Finally, Mr. Burns dismissed the idea that the DTE's hubs would compete for the business of light-duty vehicles noting that it designed

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[1818] 8 Tr 3828.
[1819] 7 Tr 2515.
[1820] 7 Tr 2515.
[1821] 7 Tr 2516.
[1822] 7 Tr 2516.
[1823] 7 Tr 2516.
[1824] 4 Tr 434-435.

the Charging Hub rate with a large session fee to disincentivize light-duty vehicles from using the site.[1825]

In Staff's rebuttal, Mr. Freeman characterized the concerns raised by EVgo and ChargePoint as "unfounded" because the pilot only encompasses two Charging Hubs, and such concerns would be more appropriate if there was a later proposal to expand the pilot into a large-scale program.[1826] Mr. Freeman added that the Charging Hub proposal addressed the current information gap for MD and HD fleet EVs, and it would provide the Company with insights on distribution and transmission system impact.[1827]

Mr. Deal agreed with Staff that it was important for the utility to gain data on fleet charging, but he maintained that DTE could acquire the necessary data at a lower cost to ratepayers through fleet-specific rebates or public-private partnerships.[1828] Mr. Deal reiterated ChargePoint's opposition to the Company's Charging Hub proposal and again suggested a fleet-specific make-ready rebate program in its place.[1829]

In rebuttal, Ms. Dumit took issue with the testimony offered by ITC witness Adarkwa in support of the Charging Hub proposal. Ms. Dumit explained that Mr. Adarkwa's testimony, and ITC's responses to discovery, do not provide any meaningful information about ITC's ostensible collaboration with the Company on siting and developing any potential charging hubs.[1830] Witness Dumit asserted that ITC's inability

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[1825] 7 Tr 2518.
[1826] 8 Tr 5550.
[1827] 8 Tr 5549-5550.
[1828] 8 Tr 4608.
[1829] 8 Tr 4608-4609.
[1830] 8 Tr 4702, 4703.

to provide meaningful details suggests that the Charging Hub proposal is a "preliminary idea that has not been properly and adequately vetted."[1831]

Mr. Jester's rebuttal reiterated that DTE should provide grid information to third parties. Mr. Jester recommended either approving the Charging Hub proposal and specifically limiting it to merely piloting the concept, or else adopting the recommendation of EVgo to use an RFP process to develop two pilot charging hubs.[1832]

Mr. Ashley, offering rebuttal[1833] on behalf of Zeco Systems, critiqued the testimony offered by Mr. Deal and Ms. Dumit. He opined that the Charging Hubs proposal addressed gaps for MD and HD EVs that would "improve the private market conditions" for investment in EVs.[1834] According to Mr. Ashley, the concern was not the effect that Charging Hubs would have on the private market, but that the utility's "proposal for deployment timing is not soon enough" to improve market adoption of EVs.[1835] Accordingly, Mr. Ashley supported the proposal and advocated a more expeditious timeline for the implementation of Charging Hubs.[1836]

In initial and reply briefs, the parties generally reiterate the points and arguments developed in their direct and rebuttal testimony.[1837] However, in reply briefs, both ChargePoint and EVgo provide further development of their opposition to utility-owned Charging Hubs. ChargePoint argues that DTE's assertion that no third parties have sought to develop fleet-charging facilities is without merit because the design of DTE's

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[1831] 8 Tr 4703.
[1832] 8 Tr 4114-H.
[1833] Mr. Ashley did not offer direct testimony.
[1834] 8 Tr 4726.
[1835] 8 Tr 4726.
[1836] 8 Tr 4726; 4728.
[1837] DTE brief, 146-153; DTE reply, 119-120; Staff brief, 211; ITC brief, 9-12; ChargePoint brief, 7-10; ChargePoint reply, 1-3; EVgo brief, 11-15; EVgo reply, 2-6; MNSC brief, 150-151; MNSC reply, 12; Zeco brief, 8-9. Zeco reply, 5.

Make-Ready Rebate program created that outcome by turning away projects that would require larger investments.[1838] EVgo echoes this sentiment stating that DTE failed to consult third parties to determine their willingness to build fleet-charging hubs and adding that it would be less expensive for third parties to build such hubs with incentives from the utility.[1839] Both parties reiterate their preference for a fleet-specific make-ready rebate program.

This PFD agrees with Staff and recommends approving the Charging Hubs pilot as described by the Company with the proviso that the pilot is limited to two hubs, and any proposed expansion of company-owned hubs will be carefully scrutinized. This PFD shares the concerns of EVgo, ChargePoint, and others regarding the potential negative effect that utility-owned charging hubs could have on the competitive charging market. Such concerns would be particularly salient if DTE proposed a large-scale entrance into the charging market. However, such concerns appear overstated in relation to this pilot program, which encompasses a maximum of only two Charging Hubs and focuses on gaining information regarding MD and HD fleet EV charging. In short, this PFD views this pilot in a limited fashion and does not consider it to be implicit approval for the utility to enter the charging market in a large scale.

Nevertheless, as requested by EVgo, ChargePoint, and other parties, this PFD also recommends requiring DTE to facilitate the siting of third-party charging hubs by providing regularly updated capacity maps with additional information like load serving capacity at substation and circuit levels, feeder identification and characteristics,

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[1838] ChargePoint reply, 2.
[1839] EVgo reply, 3.

substation source, voltage information, and other “last mile” grid information. DTE presumably possesses such information, and it touted its ability to identify areas with sufficient power supply as a reason that it was uniquely suited to build charging hubs. However, DTE did not provide cogent reasons against sharing this grid information to better assist interested non-utility market participants in locating sites that are potentially suitable for charging hubs.

f. Transit Batteries / eBus Batteries

Mr. Burns stated that through the company’s Transit Battery proposal, DTE would incentivize the purchase of electric buses. Through this pilot, a transit agency would purchase an electric bus directly from the manufacturer, but the upfront cost would be discounted by the price of the bus’s battery, which would be borne by DTE.[1840] In turn, the utility would own the battery and collect data from it, while the transit agency would be responsible for a monthly cost recovery fee under the company’s proposed electric bus (eBus) tariff, Rider 21.[1841] The transit agency would take ownership of the battery after the company’s costs were recovered.[1842] Mr. Burns explained that the eBus tariff was based on the “Pay as You Save” (PAYS) model developed by the Energy Efficiency Institute as a method to promote the adoption of beneficial technologies that have prohibitive initial costs.[1843] Mr. Burns acknowledged that the initial cost of the battery would be funded upfront through rates, but he opined that the program would be rate neutral because that amount would be made up by increased revenue from overnight depot charging and a monthly fee calculated upfront to cover the remaining

[1840] 7 Tr 2446.
[1841] 7 Tr 2446.
[1842] 7 Tr 2446.
[1843] 7 Tr 2446, 2447.

gap in battery cost that would be implemented through Rider 21.[1844] DTE seeks $0.4 million in capital expenditures to deploy one eBus through the test period.[1845]

Mr. Freeman testified that Staff supported the Transit Battery proposal noting that it would lead to valuable insights and would also be rate neutral.[1846]

Mr. Jester offered strong support for the Transit Batteries proposal testifying that it would aid mass transit agencies overcome the high upfront cost of electric buses.[1847]

Mr. Richter opposed utility ownership of capital equipment, including transit bus batteries, contending that it drives up costs to ratepayers because the cost is added to the utility's rate base.[1848]

On behalf of the CEO, Ms. Cobaleda testified that the DTE's proposal "did a great job" utilizing the PAYS model.[1849] However, she opined that the program should be expanded, even as a pilot, to include more transit buses and to include school buses as well.[1850] Ms. Cobaleda explained that four or five buses, instead of just one or two, would allow the pilot to capture more data, and the expansion of the pilot would not affect rates because the program is designed to be rate neutral.[1851]

In rebuttal, the Mr. Burns expressed that DTE was willing to expand the program to include more transit buses since the program is participant funded and aligns with federal grant opportunities.[1852] Mr. Burns also stated that the utility "would not oppose"

[1844] 7 Tr 2449.
[1845] 7 Tr 2449; see also Exhibit A-12, Schedule B5.9, p 4, line 6.
[1846] 8 Tr 5542.
[1847] 8 Tr 3829.
[1848] 8 Tr 3284.
[1849] 8 Tr 3558.
[1850] 8 Tr 3555.
[1851] 8 Tr 3558, 3559.
[1852] 7 Tr 2523.

an expansion to include school buses, and he proposed changing the name of the pilot to "eBus Batteries" to reflect its larger scope.[1853]

In briefing, the parties repeat the positions that they asserted in their direct and rebuttal testimony.[1854]

This PFD recommends approving and expanding the scope of the Transit Batteries/eBus Batteries pilot as suggested by Ms. Cobaleda and as assented to in the Company's rebuttal testimony and briefing. The enlarged scope of the proposed pilot will allow DTE to collect more data on bus electrification while maintaining an overall neutral effect on rates. This PFD recognizes Mr. Richter's concern about utility ownership of batteries driving up rates, but this pilot was designed to ultimately be rate base neutral, and the transit agency would own the battery after the utility's costs were recovered.

g. TNC Driver Rebates

Mr. Burns testified that DTE envisioned transportation network company (TNC) Driver Rebates, (i.e. rebates for drivers that use their vehicles to offer ridesharing services), as a way to bring equitable access to EVs.[1855] He explained that TNC drivers are more likely than average to come from demographic groups that are underrepresented in the general EV-owning population, electrifying TNC vehicles would reduce air pollution in low-income areas, and electrifying TNC vehicles would also double as an education program because many riders would be exposed to an EV for

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[1853] 7 Tr 2524.
[1854] DTE brief, 153; DTE reply, 123; Staff brief, 212-213; CEO brief 77-81.
[1855] 7 Tr 2456.

the first time.[1856] The utility proposed TNC Driver rebates of $5,000 for EVs that meet the partnering TNC's requirement.[1857] Mr. Burns specified that DTE was exploring a potential partnership with ridesharing company Lyft, and the company is requesting $0.5 million in O&M to fund TNC Driver rebates for up to 100 TNC drivers through the test period.[1858]

Mr. Freeman testified that Staff is generally supportive of this proposal to promote more equitable access to EVs.[1859] Nevertheless, Mr. Freeman asserted that approval of such a proposal should be contingent upon two requirements. First, that the program should be reported in detail in the annual EV stakeholder update reports. Second, that DTE should discuss the program and report regularly to the Commission's Low-Income Workgroup and Energy Affordability and Access Collaborative.[1860]

Mr. Jester offered support for the TNC Driver Rebate proposal only adding that it could be improved by ensuring that the rebate was available on a point-of-sale basis to better support low-income EV purchasers.[1861]

In rebuttal, Mr. Burns testified that the company agreed to Staff's requests regarding reporting requirements and regular check-ins in with the Commission workgroups listed by Staff.[1862]

[1856] 7 Tr, 2456, 2457.
[1857] 7 Tr, 2457.
[1858] 7 Tr 2458; see also Exhibit A-12, Schedule B5.9, p 4, line 10.
[1859] 8 Tr 5544.
[1860] 8 Tr 5544.
[1861] 8 Tr 3829, 3830.
[1862] 7 Tr 2514.

In briefing, the parties reiterate the positions staked out in their testimony, though Staff adds that it fully supports the pilot now that DTE assented to the additional requirements requested by Staff.[1863]

This PFD recommends approving the TNC Driver Rebate pilot as described by the Company now that it assented to Staff's request regarding reporting requirements. This PFD further recommends that DTE explore the possibility of making the rebate available at the point-of-sale as suggested by Mr. Jester.

h. Income-Eligible Rebates

Mr. Burns testified that the EVs currently cost $10,000 more on average than an equivalent gasoline-powered vehicle, which can be a significant barrier for low-income households.[1864] To support greater access to EVs, DTE proposes income-based rebates of $1,500 for eligible customers purchasing or leasing a new or used EV with a total price of $50,000 or less.[1865] Mr. Burns specified that customers would be eligible for this rebate if their household participated in an income-eligible public assistance program run by DTE or by the government (such as Michigan Food Assistance/SNAP), or if the customer provided verification of income that was under 400% of the federal poverty level guidelines.[1866] DTE sought approval of a $1.917 million regulatory asset for this program to support up to 1,300 income-eligible rebates through the test period.[1867] Mr. Burns asserted that the company would seek to "create a pathway for voluntary donations" to offset the cost of Income-Eligible Rebates in a similar fashion to

[1863] Staff brief, 213-214.
[1864] 7 Tr 2459.
[1865] 7 Tr 2459.
[1866] 7 Tr 2459-2460.
[1867] 7 Tr 2460; see also Exhibit A-12, Schedule B5.9, p 4, line 19.

the MIGP Low-Income Donation Pilot previously approved by the Commission in Case No. U-20713.[1868]

Mr. Freeman testified that Staff is supportive of this proposal and is "intrigued" by the idea of utilizing a program similar to the MIGP Low-Income Donation Pilot.[1869] But Mr. Freeman expressed concerns that there was no elaboration on how such a program would be structured and administered, so he suggested that the proposal should be fleshed out in greater detail before approval.[1870] Mr. Freeman also recommended the same requirements as for TNC Driver Rebates, i.e. regular reporting in the annual EV stakeholder update report and regular check-ins with the Commission's Low-Income Workgroup and Energy Affordability and Access Collaborative.[1871]

Mr. Jester offered general support for the income-eligible EV Rebates adding that the proposal could be improved by ensuring that the rebate was available on a point-of-sale basis to better support low-income EV purchasers.[1872] Mr. Jester also criticized the Company's plan to fund the program through donations noting that DTE proposed to spend $1.3 million in IT to develop the capability to accept on-line donations for the MIGP Low-Income Donation Pilot.[1873] Mr. Jester opined that it is unreasonable and imprudent to make such a large investment in the ability to receive donations when there are websites that could be used to create a donation campaign at little cost, and most of the budget for the low-income rebates could be funded by redirecting the

[1868] 7 Tr 2462.
[1869] 8 Tr 5544.
[1870] 8 Tr 5544.
[1871] 8 Tr 5544.
[1872] 8 Tr 3829, 3830.
[1873] 8 Tr 3830.

proposed IT investment.[1874] Therefore, witness Jester recommended directing the company to fund the low-income EV Rebates without reliance on donations.

In rebuttal, the Mr. Burns addressed Staff's concerns stating that DTE was exploring the possibility of collecting donations on a one-time or monthly basis, or possibly allowing recipients of other rebates in the Charging Forward program to elect to donate a portion of their rebate to the Income-Eligible Rebate element.[1875] Further, Mr. Burns stated that the Company agreed to Staff's requests regarding reporting requirements and regular check-ins with the Commission workgroups listed by Staff.[1876] Mr. Burns responded to Mr. Jester's criticism stating that the company already designed the program without reliance on donations because it did not include any revenue from donations in the cost-benefit analysis; however, the company did not believe that it should be prohibited from seeking voluntary donations to fund the rebate program.[1877]

In briefing, DTE asserts that its further explanation of the pilot and its assent to Staff's suggested reporting requirements should allay Staff's concerns.[1878] Staff agrees stating that it now recommends approving the pilot after DTE assented to reporting requirements and explained that it would seek donations to offset the rebate's cost to rate base.[1879] MNSC merely reiterates its suggestion that any rebate should be available at the point of sale.[1880] In reply briefs, the parties provided no further substantive information on this topic.

[1874] 8 Tr 3829-3830.
[1875] 7 Tr 1513.
[1876] 7 Tr 2514.
[1877] 7 Tr 2514.
[1878] DTE brief, 150.
[1879] Staff brief, 215.
[1880] MSNC brief, 150.

This PFD recommends approving the Income-Eligible Rebate pilot for the reasons stated by Staff, with the added suggestion that DTE explore the possibility of making the rebate available at the point of purchase. Mr. Jester is correct that it seems incongruous that the total cost of the proposed rebates ($1.9 million) is not far from the amount that DTE proposes to spend on developing IT capabilities to accept donations for a similar donation-based pilot program ($1.3 million); however, this PFD does not view that as a cogent criticism of this pilot proposal.

i. Commercial CaaS

Mr. Burns explained that DTE proposes a “true utility make-ready model for Commercial CaaS” in which the company will install the chargers and own and fund all the electrical infrastructure up to the chargers.[1881] The site host would own and operate the chargers and fund them through a fee on their monthly electric bill (after the Make-Ready Rebate is applied).[1882] Witness Burns stated that four customer groups would qualify for Commercial CaaS installation of Level 2 ports and DCFCs: Environmental Justice Communities (EJCs), multi-unit dwellings (MUDs), rural areas, and municipalities.[1883] The company sought approximately $1.2 million ($0.49 million in capital expenditures and $0.681 million as a regulatory asset) for this program, which would support 150 Level 2 ports and 4 DCFCs through the test period.[1884] Mr. Burns opined that this pilot incentivizes charger installation in areas that lack equitable access

[1881] 7 Tr 2463.
[1882] 7 Tr 2463.
[1883] 7 Tr 2464.
[1884] 7 Tr 2464; see also Exhibit A-12, Schedule B5.9, p 4, lines 3 and 18.

to EV charging and that have had low participation in the Charging Forward pilot programs.[1885]

Mr. Freeman stated that Staff supported this proposal in general as a way to achieve more equitable access to EVs.[1886] However, he recommended the same requirements as for TNC Driver Rebates, i.e. regular reporting in the annual EV stakeholder update report and regular check-ins with the Commission's Low-Income Workgroup and Energy Affordability and Access Collaborative.[1887]

Ms. Dumit applauded the DTE's focus on equitable access but questioned whether the utility needed to be the entity that installed chargers under the Commercial CaaS program to achieve its goals. Instead, Ms. Dumit recommended reallocating the Commercial CaaS budget to the Make-Ready Program and including features in the Make-Ready Rebate program that would foster more equitable access to EV technologies.[1888]

Mr. Deal recommended that DTE employ the same requirements that ChargePoint proposed for Residential CaaS, i.e. allow customers to select any charger that meets minimum technical requirements, and require all chargers to be networked, UL and ENERGY STAR certified.[1889] Mr. Deal also suggested that the Commission should direct the Company to modify the Commercial CaaS program to expressly allow for third-party turnkey solutions, like the one offered by ChargePoint.[1890]

[1885] 7 Tr 2465.
[1886] 8 Tr 5544.
[1887] 8 Tr 5544.
[1888] 8 Tr 4688, 4689.
[1889] 8 Tr 4592.
[1890] 8 Tr 4593.

In rebuttal, Mr. Burns agreed to Staff's requests regarding reporting requirements and regular check-ins in with the Commission workgroups listed by Staff.[1891] Mr. Burns responded to Ms. Dumit's concerns stating that the Commercial CaaS program was needed to achieve more equitable access to EV technology because the targeted customer segments have thus far had low participation in the Charging Forward pilots, like Make-Ready Rebates. Mr. Burns stated that the company also assented to allowing participants to select any charger from the company's Make-Ready Rebate list.[1892]

In briefing, the parties maintain and reiterate positions consistent with their testimony submitted in this matter.[1893]

This PFD recommends approving the proposed Commercial CaaS pilot as described by the company now that it has agreed to Staff's requests regarding reporting and has agreed to allow participants to select any charger that is qualified under the Make-Ready Rebate Program, i.e. a charger that is UL and ENERGY STAR certified.

This PFD declines to accept Ms. Dumit's recommendation to abandon the Commercial CaaS pilot and reallocate its resources to the Make-Ready Rebate pilot. As stated by the company, the Commercial CaaS pilot is tailored to reach customer segments underrepresented in the adoption of EV technologies and that have seen low participation in the Company's Charging Forward pilots. DTE's proposed Commercial CaaS pilot offers a reasonable model to increase equitable access to EVs; it need not be abandoned merely because another model could potentially also be used to reach the same goal. Indeed, one of the Company's stated goals in testing the Commercial

[1891] 7 Tr 2514.
[1892] 7 Tr 2523.
[1893] DTE brief, 153; DTE reply, 122-123; Staff brief 210-211; ChargePoint brief, 10; EVgo brief, 5-6.

CaaS model in this pilot is to compare its costs and benefits against the Make-Ready Rebate program.[1894]

Finally, this PFD declines Mr. Deal's recommendation that the Commercial CaaS pilot should be modified to expressly incorporate third-party turnkey solutions. As described by Mr. Deal, third parties such as ChargePoint have business models that offer turnkey solutions and subscription pricing to induce commercial site hosts to install chargers. It is unclear how these third-party services could be incorporated into the utility's Commercial CaaS pilot to the extent that they essentially offer the same service. Instead, it would appear incumbent upon third parties to promote their own turnkey and subscription-based solutions to potential site hosts interested in installing chargers.

j. Emerging Technology Fund

Mr. Burns stated that DTE desires to proactively test new technologies in the rapidly evolving EV market; however, he asserted that regulatory lag prevents the company from having the funds to timely partner with other companies on new technology demonstrations.[1895] Accordingly, the utility requested a $0.9 million regulatory asset for an "Emerging Technology Fund" to be used on EV technology demonstrations through the test period.[1896] Mr. Burns asserted that the company would ensure that the fund's expenditures were reasonable and prudent by creating and seeking the approval of expenditures from a small advisory committee of external experts, in addition to DTE's own experts.[1897]

[1894] 7 Tr 2467.
[1895] 7 Tr 2468.
[1896] 7 Tr 2469; see also Exhibit A-12, Schedule B5.9, p 4, line 23.
[1897] 7 Tr 2470.

Mr. Freeman stated that this proposal is responsive to previous Staff testimony regarding EVs, and such a fund would allow the company to rapidly test emerging EV technologies without regulatory lag.[1898] He explained that Staff conditionally supports the proposal provided that a member of Staff is selected to serve as a member of the small advisory committee in an ex-officio capacity.[1899] He also suggested that as a first-of-its-kind proposal, this program should be subject to regular meetings and documentation of its benefits, costs, and results.[1900]

In briefing, DTE provides no further details, and Staff reiterates that its support is contingent upon DTE's agreement to Staff's suggestions.[1901]

This PFD agrees with Staff and recommends conditional approval of the Emerging Technology Fund pilot provided that: (1) DTE allows Staff to select one of its members to sit on the pilot's advisory committee in an ex-officio capacity, and (2) DTE assents to holding regular meetings with Staff and presenting detailed documentation of the costs, benefits, and results generated by this pilot. Fulfillment of these two conditions will moderate concerns that this PFD otherwise has regarding the somewhat unique and open-ended nature of this proposed pilot.

k. Future Charging Forward Program Full-Scale Proposal

Mr. Burns testified that DTE believes that a full-scale Charging Forward program will soon be necessary to support the rapidly developing EV market and to promote off-peak charging.[1902] However, Mr. Burns did not offer a timeframe in which the company

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[1898] 8 Tr 5545.
[1899] 8 Tr 5545.
[1900] 8 Tr 5545.
[1901] Staff brief, 215.
[1902] 7 Tr 2471.

envisioned a full-scale version of the Charging Forward program. Instead, Mr. Burns explained that the utility may be able to propose long-term solutions more quickly for some elements that have already been tested whereas it may take longer to develop proposals for the newly proposed expansion pilots.[1903] According to Mr. Burns, the appropriate next steps are to continue refining the existing elements and testing the newly proposed expansion elements before making any long-term proposal.[1904]

Staff requested that the company file a final plan for Charging Forward, with a rigorous cost-benefit analysis, in a separate docket within the next 18 months.[1905]

Mr. Jester opined that the scale of the Charging Forward program proposed by the Company was “insufficient to meet EV Charging infrastructure needs in its service territory through 2025.”[1906] Accordingly, he suggested that the Commission direct the company to propose a permanent, full-scale program by March 15, 2023.[1907] Mr. Jester also added several recommendations on how to structure permanent EV program proposals.[1908] Additionally, Mr. Jester also proposed requiring the company to file information in its future rate cases about the net effects of EV adoption, including seven different reporting requirements.[1909]

[1903] 7 Tr 2472.
[1904] 7 Tr 2472.
[1905] 8 Tr 5545.
[1906] 8 Tr 3823
[1907] 8 Tr 3836.
[1908] More specifically, he suggested that non-participating ratepayers should be no worse off than they would be absent permanent EV programs, direct revenues in excess of costs should fund EV programs to support the MI Healthy Climate Plan, contributions from customers for system upgrades necessary to connect their chargers should be waived, and net charging revenues from public chargers should be reinvested in more public chargers. 8 Tr 3837-3839.
[1909] Mr. Jester recommended requiring the Company to report: (1) the number of EVs in the Company’s territory by class, (2) the amount of electricity delivered to EVs by rate schedule, (3) revenue from EV charging by rate schedule, (4) cost of EV power supply by rate schedule, (5) gross margin for EV charging by rate schedule, (6) revenue requirements by rate schedule, and (7) net margin benefitting customers by rate schedule. 8 Tr 3840.

Dr. Sherman opined that it was likely that EV adoption rates would exceed the company's expectations. Consequently, she recommended that the Commission direct the company "to take steps in its next rate case that will transition from EV charging through pilot projects to the inclusion of EV charging infrastructure in [the Company]'s ongoing budgeting and revenue recovery as a basic utility function."[1910] Dr. Sherman testified that the Commission should direct DTE to include in future rate case filings an analysis of the net effects of EV adoption and charging including at least seven different reporting components, which were substantially similar to those suggested by Mr. Jester.[1911] Dr. Sherman also opined that DTE should include EV adoption rate and charging use forecasts in its sales forecasts.[1912] Additionally, Dr. Sherman recommended that the Commission encourage DTE to propose a system of rebates for EV charging infrastructure that is not limited to a specific number of customers over a specific period of time.[1913]

In rebuttal, Mr. Burns asserted that DTE would be unable to file a final plan as contemplated by Staff because various elements of Charging Forward are at different stages of maturity.[1914] Mr. Burns also expressed that Charging Forward would have to continue to change to maximize funding from evolving state and federal funding award programs.[1915] Instead of introducing a permanent plan within 18 months, he proposed

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[1910] 8 Tr 4379.
[1911] More specifically, she proposed that the analysis should include (1) the number of EVs in the Company's territory by class, (2) the amount of electricity delivered to EVs by rate schedule, (3) revenue from EV charging by rate schedule, (4) cost of EV power supply by rate schedule, (5) gross margin for EV charging by rate schedule, (6) revenue requirements by rate schedule, and (7) net margin benefitting customers by rate schedule. 8 Tr 4380-4381.
[1912] 8 Tr 4381.
[1913] 8 Tr 4382-4383.
[1914] 7 Tr 2506.
[1915] 7 Tr 2506.

that the company should begin "to introduce permanent offerings, as applicable, starting with its next rate case."[1916] Mr. Burns added that despite Staff's request for a "rigorous cost-benefits analysis," there was "not yet alignment on the approach," and the utility did not agree with the methods proposed by witnesses Jester and Sherman.[1917] He asserted that requiring a cost-benefit analysis as a condition of proposing a permanent program would "unnecessarily end the Company's ability to transition relevant Charging Forward elements to permanent offerings[.]"[1918]

Mr. Burns also explained that for various technical and practical reasons it was not possible for the company to report six of the seven items proposed by Dr. Sherman and Mr. Jester.[1919] He asserted that the only requested item that the Company could report was the number of electric vehicles by class registered within the Company's service territory, unless "class" meant "rate class," in which case he declared even that would not be possible.[1920] Mr. Burns added that "significant speculation" would be required to provide the analysis requested by Dr. Sherman, but such speculation could yield inaccurate results.[1921] Finally, Mr. Burns responded to Dr. Sherman's request for EV adoption rates and charging use forecasts in its sales forecasts by noting that the sales forecast provided by company witness Mr. Leuker already includes such information.[1922]

[1916] 7 Tr 2506.
[1917] 7 Tr 2506.
[1918] 7 Tr 2506.
[1919] 7 Tr 2507.
[1920] 7 Tr 2507.
[1921] 7 Tr 2507, 2510.
[1922] 7 Tr 2510.

In rebuttal on behalf of Staff, Mr. Revere disagreed with Mr. Jester's suggestions regarding how future EV proposals should be structured. Mr. Revere explained that the goal of ratepayer-funded programs should maximize the net benefit to all ratepayers as ratepayers, and allowing the net benefit to accrue to the benefit of EV owners alone was antagonistic to that goal.[1923] Mr. Revere asserted that an overarching issue with Mr. Jester's proposals was that they subsidized EV owners at the expense of non-EV ratepayers, and they also failed to adequately include costs when considering the net benefit.[1924] Mr. Revere opined that Dr. Sherman's proposals suffered from the same flaws and should also be rejected.[1925]

Mr. Krause testified that Staff believes there was "an overemphasis by some parties as to the extent of utility and therefore electricity customer responsibility."[1926] He specified that utilities should not be installing EV infrastructure for the sake of installing infrastructure, "but instead should be looking for programs that maximize the grid and customer benefits in relation to the rate-funded expenditures."[1927] He recommended that the Commission consider rate dilution in response to revenue from increase EV charging.[1928] Mr. Krause testified that Staff did "not entirely" agree with Mr. Jester's proposal that distribution system upgrades for residential customers should be provided by the Company without some contribution in aid of construction (CIAC) by the customer.[1929] Instead, Staff suggested that customers be allowed one 40-amp or lower

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[1923] 8 Tr 5155.
[1924] 8 Tr 5155.
[1925] 8 Tr 5155.
[1926] 8 Tr 5510-F.
[1927] 8 Tr 5510-G.
[1928] 8 Tr 5510-J.
[1929] 8 Tr 5510-H-5510-I.

charger without being assessed costs, but selection of larger chargers or multiple chargers should trigger incremental CIAC contributions.[1930] Finally, Mr. Krause explained that Staff generally supported the recommendations of Dr. Sherman to require seven different reporting criteria related to EVs with three additions: (1) residential rate schedules should be broken down by Level 1/Level 2 or amperage where possible, (2) commercial and industrial rate schedules should be broken down into Level 2/DCFC where possible, and (3) the revenue impact of the demand charge holiday should be addressed, including customers on rate D3 that may be moved to rate D4 in 2024.[1931]

In briefing, DTE repeats the points in its testimony, including its opposition to filing a final plan and its proposal to introduce permanent programs in a piecemeal fashion beginning in its next rate case.[1932] In turn, Staff retreats from its request for a final plan within 18 months and more generically suggests that the utility should "provide additional information regarding the future of the EV pilot programs in its next rate case."[1933] MEIBC maintains that the Commission should direct DTE to transition its full Charging Forward program to a permanent program in its next general rate case.[1934] MEIBC adds that this directive would be consistent with how the Commission treated the Consumers Energy EV pilots in Case No. U-20963.[1935] MNSC also largely reiterates

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[1930] 8 Tr 5510-I.
[1931] 8 Tr 5510-I.
[1932] DTE brief, 149.
[1933] Staff brief, 217.
[1934] MEIBC brief, 4.
[1935] MEIBC brief, 5 (See December 22, 2021 order, Case No. U-20963, pages 311-312.)

points derived from the testimony that it offered, and it echoes MEIBC's call to require the utility to propose a permanent EV plan in its next rate case.[1936]

In reply briefing, DTE adds that it is also unable to provide information relating to the first two of Staff's three additional proposed reporting criteria.[1937] Regarding Staff's third request, DTE asserts that the premise of the request (i.e. that there is a demand component in rate D3) is factually incorrect such that the Company cannot agree with Staff's request.[1938]

In its reply, MEIBC argues that Staff's position is inconsistent with the Commission's goals. MEIBC recaps that Staff asserted that utility investment in EV infrastructure was limited (i.e. to constructing a skeleton network of chargers and reducing barriers to EVs) and was not intended to meet all possible demand for EV infrastructure.[1939] MEIBC argues that the Commission adopted a more expansive view in the last rate case involving Consumers Energy in which the Commission stated that it wanted to accelerate that utility's transition from pilot programs to permanent programs to support the estimated growth of EV adoption.[1940] Accordingly, MEIBC urges that the Commission should ensure that infrastructure programs are designed to meet demand for EVs.[1941]

For its reply, MNSC notes its general agreement with Staff that permanent EV proposals should represent a net benefit to customers, should involve some form of suspension of contribution in aid of construction for EV charging, and should carefully

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[1936] MNSC brief, 152.
[1937] DTE reply, 118.
[1938] DTE reply, 118.
[1939] MEIBC reply, 5.
[1940] MEIBC reply, 5-6 (citing See December 22, 2021 order, Case No. U-20963, pages 311-312).
[1941] MEIBC reply, 5.

consider how revenues from EV charging are reinvested to accelerate EV adoption.[1942] MNSC candidly acknowledges that "[t]hese details are perhaps best addressed in a future rate case."[1943]

This PFD recommends that the Commission should direct DTE to present a plan for a permanent program for its currently existing Charging Forward pilots in its next rate case. DTE expressed concern that some elements of Charging Forward are more mature than others. This PFD believes that most of the pre-existing pilots are generally well-developed, and the utility should be able to present a permanent proposal for as many of the currently existing EV pilots as possible. Nevertheless, to address DTE's concerns, this PFD recommends that if the company has cogent reasons that certain pilots are not sufficiently developed for final proposals, then it can so state in its next rate case and the Commission may consider setting another timeline to address final proposals for those specific pilots.

DTE also objected to including a cost-benefit analysis asserting that doing so would end its ability to transition the pilots to permanent offerings. This PFD stresses that the Commission should have a cost-benefit analysis to assist in evaluating the merits of the proposals relative to their costs. This PFD notes that to the extent that there may be disagreement about the approach to use to measure costs and benefits, such issues can be further explored and resolved in the next case.

This PFD declines—at least at this time and based on this record—to impose the seven reporting requirements for EV-related data recommended by Dr. Sherman and

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[1942] MSNC reply, 16.
[1943] MSNC reply, 17.

Mr. Jester, as well as the additional three reporting details recommended by Staff. The company specified that for various reasons it was not feasible to report actual data for at least six of the seven items; further, the utility stated that it could not address the three additional requirements suggested by Staff. This PFD is not yet prepared to impose the suggested reporting requirements on this record given the questions that remain about the viability of such requirements. This PFD suggests that further engagement on this issue should occur between the parties and the company in the next rate case to better develop the record regarding the feasibility of gathering these data points.

Additionally, this PFD declines to adopt—at least at this time—the various other recommendations related to EVs put forward by Mr. Jester and Dr. Sherman. As MNSC candidly acknowledged in its reply brief, such details are perhaps best addressed in DTE's next rate case in which the utility is expected to put forward at least some permanent proposals for the Charging Forward program. Indeed, deferring such discussions is consistent with the Commission's past practice regarding EV pilot programs.[1944]

5. Residential Battery pilot

Mr. Burns testified that the Company proposes a customer-sited behind-the-meter (BTM) residential battery pilot for up to 500 residential customers that would host up to 1,000 customer-sited batteries that would provide backup power for homes during an outage.[1945] The Company would own the installed batteries and would have full

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[1944] See December 22, 2021 order, Case No. U-20963, page 312 (Directing Consumers Energy to explore how it could utilize CIAC policies to support EV infrastructure in its next rate case in which it was directed to propose permanent EV programs).
[1945] 7 Tr 2484, 2486.

access to them to derive learnings.[1946] Mr. Burns explained that the program would be offered for free to 250 income-eligible customers, but the remaining 250 customers would pay a tiered monthly subscription fee at pricing yet to be determined, but would likely range from $29.99 to $49.99 per month.[1947] According to Mr. Burns, the Company would use a RFP to identify suitable battery providers and the pilot would not include a bring your own device (BYOD) option.[1948] The Company anticipated operating the pilot for 10 years—the useful life of the batteries—and obtaining key learnings after 3 or 4 years.[1949] Mr. Burns explained that this pilot would target key learnings including, among others, resiliency as a service and customers' willingness to pay for the same, battery control, and exploring battery technology to prepare for implementation of FERC Order 2222 relating to distributed storage.[1950] Mr. Burns testified that the pilot would cost $3.3 million ($3.144 million in capital expenditures and approximately $184,000 in O&M).[1951] The Company's pilot proposal was widely panned by the intervening parties.

Mr. Matthews testified that in Staff's view, the Company's proposal suffered from "several shortcomings," including the program's narrow focus on outage management and its exclusion of residences with home solar that could otherwise provide learnings on distributed generation and storage.[1952] Mr. Matthews also pointed out that FERC Order 2222 allows third-party batteries to be aggregated, so there would be value in

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[1946] 7 Tr 2486.
[1947] 7 Tr 2487.
[1948] 7 Tr 2490.
[1949] 7 Tr 2491.
[1950] 7 Tr 2490-2491.
[1951] 7 Tr 2492; see also Exhibit A-12, Schedule B5.10, page 1, lines 5 and 10.
[1952] 8 Tr 5378.

including third-party batteries in the pilot.[1953] Additionally, he opined that "third-party ownership allows for better price signals to customers, as there is no subsidization of the program costs to non-participants."[1954] Mr. Matthews stated that Staff recommends that the Commission decline to approve the residential battery pilot, and he opined that the Company should work with stakeholders to further develop the pilot in conjunction with the Commission's recommendations in its August 11, 2021 Order in Case No. U-21032.[1955]

On behalf of the CEO, Mr. Pereira criticized the proposal for focusing predominantly on backup power and excluding customers with solar DG from participating.[1956] Responding to the Company's proposal to own the batteries, he explained that it was "unclear why exclusive Company ownership is required."[1957] Additionally, he opined that the proposal lacked important details, including what circuits the pilot would target, the specific fee structure, and performance metrics for the Company's proposed learnings.[1958] Mr. Pereira recommended that the pilot should be restructured to include solar customers, allow BYOD storage, and clarify performance metrics.[1959]

On behalf MEIBC and IEI, Dr. Sherman recommended rejecting the pilot and voiced concerns like those expressed by Staff and Mr. Pereira. Additionally, Dr. Sherman strongly opposed the Company's plan to own the home batteries opining that

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[1953] 8 Tr 5379.
[1954] 8 Tr 5381.
[1955] 8 Tr 5381.
[1956] 8 Tr 3653.
[1957] 8 Tr 3653.
[1958] 8 Tr 3653.
[1959] 8 Tr 3654.

"utility ownership of customer-sited BTM batteries inappropriately inserts rate-regulated monopolies into the growing competitive market for residential energy storage."[1960] Dr. Sherman added that "[t]esting customers' willingness to pay more than they are already paying each month to reliably receive the product the utility has been given a monopoly right to deliver seems ludicrous."[1961] Moreover, Dr. Sherman pointed out that the Commission rejected similar battery-related proposals from Consumers Energy in Cases U-20963 and U-20649.[1962]

On behalf of the DAAO, Mr. Koeppel criticized the structure of the proposed Residential Battery pilot as an effort by the Company "to dominate the residential battery market, to frame reliability as a premium service rather than a baseline expectation, to capture all of the value from residential batteries for the Company, and to guarantee earnings on the Company's capital investment[.]"[1963] Mr. Koeppel critiqued the pilot's proposal for utility-owned batteries asserting that customer ownership of batteries could reduce the cost of the pilot and further expand its reach.[1964] Mr. Koeppel also opined that a pay-to-participate model would favor high-income customers which would disadvantage and disproportionately exclude BIPOC communities due to the close correlation between race and class.[1965] Mr. Koeppel recommended restructuring the pilot to remove the willingness-to-pay fee structure, to allow BYOD and PAYS options to incentivize customer ownership of batteries, to add outflow credits to

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[1960] 8 Tr 4405.
[1961] 8 Tr 4414.
[1962] 8 Tr 4407-4408.
[1963] 8 Tr 4297.
[1964] 8 Tr 4299.
[1965] 8 Tr 4302.

compensate participants for electricity provided to the grid, and to include various equity-focused credits.[1966]

On behalf of the City of Ann Arbor, Mr. Grocoff testified that the Company's proposed pilot was not attractive to the Company's customers given its proposed price range and limited benefits.[1967] Mr. Grocoff opined that customers value home solar generation and the ability to own their own battery, neither of which was incorporated into the Company's proposal.[1968]

In rebuttal, Mr. Burns testified that company ownership of the battery systems was optimal citing the ability to achieve critical circuit-level concentration, current market dynamics, and safety reasons.[1969] Mr. Burns asserted that FERC's order 2222 specified a minimum aggregation threshold of capacity and that a certain threshold within a circuit was also required to use the batteries as a grid asset.[1970] He opined that company ownership of the batteries was the easiest way to achieve this concentration.[1971] Mr. Burns explained that the home battery market was nascent with adoption skewing heavily toward high-income households, so BYOD models would not support equity.[1972] Finally, Mr. Burns asserted that company ownership and control of the batteries promoted safety compared to a BYOD structure because customers controlling their

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1966 8 Tr 4307.
1967 8 Tr 3312.
1968 8 Tr 3312-3313.
1969 7 Tr 2525.
1970 7 Tr 2525.
1971 7 Tr 2525.
1972 7 Tr 2526.

own batteries could potentially take actions harmful to the grid during periods of high demand.[1973]

In their initial and reply briefs, the parties principally restate the points and arguments developed in their respective testimonies.[1974]

This PFD recommends rejecting the residential battery pilot as currently proposed by DTE and disallowing all associated expenses; indeed, the various concerns raised by the intervening parties have substantial merit, and they touch upon nearly every aspect of the pilot. This PFD notes that the Commission recently rejected a similar home battery pilot proposed by Consumers Energy in case U-20963 expressing concerns that the Consumers Energy pilot was limited to back-up power, failed to explore the full range of benefits that batteries can provide, and raised questions about the necessity of utility ownership of BTM batteries.[1975] DTE's current home battery proposal suffers from those same shortcomings.

This PFD agrees with Staff and recommends that the Company should seek extensive stakeholder input and redevelop the pilot proposal in conjunction with the Commission's recommendations in its August 11, 2021 Order in case U-21032 (addressing the development of tariffs that provide a pathway for the deployment of energy storage resources). This PFD further agrees with the various intervenors and recommends that DTE's revised proposal should explore a BYOD option and should seek to test the full range of benefits that batteries can provide, including but not limited to the interaction of home solar with battery storage. This PFD also suggests that DTE

[1973] 7 Tr 2526.
[1974] See DTE brief, 153; DTE reply, 123-125; Staff brief, 142; CEO brief, 69; CEO reply, 11; MEIBC brief, 26; DAAO brief, 68; DAAO reply 3; MI MAUI brief, 29; MI MAUI reply, 17-19.
[1975] See December 22, 2021 order, Case No. U-20963, pages 323-326.

should study the Commission's order in case U-20963 for guidance on what the Commission would like to see in relation to a home battery pilot.[1976] This PFD believes that the Company's next home battery pilot proposal will significantly benefit from stakeholder input to ensure that the refined proposal better addresses the substantial concerns raised by the intervenors in this case.

B. Earnings Sharing Mechanism

In response to ABATE's concerns about DTE's use of a projected test year being a major driver of DTE's proposed rate increase in this case, Mr. Dauphinais makes two "near-term" recommendations, the second of which is that the Commission impose an earnings sharing mechanism on DTE "to curtail the degree to which DTE can earn over its authorized rate of return on equity due to its use of a projected test year."[1977] Specifically, he recommends that DTE return, with interest, 100% of its Michigan electric jurisdictional earnings more than 30 basis points over its authorized rate of return on common equity that is ultimately granted by the Commission in this proceeding.[1978] He asserts that this would retain the incentive for DTE to find cost savings between base rate proceedings, ultimately leading to lower customer rates than there otherwise would be, while also ensuring DTE is not unduly enriched through its continued use of a projected test year.[1979]

In addressing why his proposal is asymmetrical in that it does not impose a surcharge on customers when DTE's earnings are more than 30 basis points below DTE's authorized rate of return, Mr. Dauphinais explains that there is no need to apply a

[1976] See December 22, 2021 order, Case No. U-20963, pages 324-325.
[1977] 8 Tr 2902.
[1978] 8 Tr 2902.
[1979] 8 Tr 2902-2903.

surcharge to customers in that situation, as the concern that is being addressed is the difficulty in ensuring DTE's electric rates are not set unreasonably high given it is using projections as the basis of its electric rates. Mr. Dauphinais explains that, unlike ratepayers, DTE is in full control of the timing of its base rate filings, the development of its projections for its projected test years and the support it provides in direct testimony for those projections.[1980]

Mr. Dauphinais states that the proposed mechanism is meant to be a second line of defense to prevent "egregious levels of overearning" by DTE due to its use of a projected test year, with the first line of defense being the careful scrutiny of DTE's projected costs and revenues.[1981] He adds that it is important to keep an incentive for DTE to seek to reasonably reduce its costs between base rate proceedings, as such cost reductions can ultimately lead to lower rates than there otherwise would be.[1982]

Mr. Dauphinais states that his proposed 30 basis point deadband is half of the 60-basis point width of Mr. Walters' 9.10% -- 9.70% range of estimated current fair market ROE for DTE.[1983] Thus, he asserts that the proposed dead band would allow DTE to fully retain any earnings in excess of its authorized rate of return on equity up to the point those excess earnings do not cause DTE to exceed the upper end of the range of the estimated current fair market ROE for DTE.[1984]

Mr. Dauphinais explained how the earnings sharing mechanism would work, in part, as follows:

[1980] 8 Tr 2903.
[1981] 8 Tr 2903.
[1982] 8 Tr 2903-2904.
[1983] 8 Tr 2904.
[1984] 8 Tr 2904.

> Specifically, I propose that within six months of the conclusion of each calendar year that DTE file with the Commission an earnings report for the just completed calendar year along with the proposed credit that would be returned to customers for any overearnings during that just completed calendar year that are in excess of 30 basis points of DTE's authorized rate of return on equity. The total amount returned to customers would be the amount over earned in excess of 30 basis points plus interest based on DTE's authorized rate of return on equity. The total amount would be returned to each customer class based on the percent revenue provided by each customer class in the Commission's final order in this rate proceeding. Once the amount is divided among the rate classes, it would then be returned to customers within each rate class on a per kWh basis.[1985]

He notes that because it will not be readily possible to know the specific changes in revenues or costs that caused the overearning, and thus, it will not be possible to return the overearnings to customer classes in the exact same manner they were collected from those classes, the most reasonable approach is to return the excess earnings to customer classes based on each class's contribution in rates to DTE's overall revenue requirement. Mr. Dauphinais adds that Northern States Power Company agreed to an earnings sharing mechanism for overearnings without a deadband in a settlement agreement in Case No. U-21097.[1986]

ABATE argues that the significant discrepancy between DTE's projected and actual costs must be addressed, and that an earnings sharing mechanism should be instituted if DTE is to continue seeking extraordinary revenues based on projected expenses which do not materialize.[1987] ABATE asserts that such a mechanism would

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[1985] 8 Tr 2904-2905.
[1986] 8 Tr 2905.
[1987] ABATE brief, 9.

both permit DTE to earn a reasonable return and protect customers from excessive and unnecessary rate recovery.[1988]

For its part, in its rebuttal, Staff did not take a position on the earnings sharing mechanism itself, but opposed ABATE's proposed refund method. Initially in rebuttal, Staff proposed that the refund be distributed to only those classes whose revenue exceeded that projected in the rate case in proportion to that excess.[1989]

> Allocating the refund in proportion to the amount the revenue collection for each class exceeded that projected in the rate case (while leaving out the classes for whom revenues were under the projection) more closely matches the refund to its cause than the method proposed by ABATE witness Dauphinais. This is also similar to the method that was used for refunds under the former self-implementation refund process approved by the Commission.[1990]

Upon further consideration, in its initial brief, Staff stated that a more appropriate method would be as described in the discovery response included in the record as Ex. AB-35, in part, as follows:

> The total amount to be refunded would be split into two amounts based on the relative proportion of: (a) the amount by which the Company's actual revenue requirement (calculated in the same manner as that used in setting rates with any revenue not attributed to collection from rates treated as a reduction to the revenue requirement) was lower than that assumed in setting rates, and (b) the amount by which collected revenues from rates for each class exceeded projected revenues from rates used in setting rates (excluding any amounts for classes for which revenues were lower than projected). . . .
>
> The amount associated with expense would be allocated to the classes based on proportion of total projected revenue used to set rates (similar to the method proposed by ABATE initially), and the amount associated with revenues would be allocated to the classes for whom rate revenues were higher than projected (and not classes for whom rate revenues were lower than projected) in proportion to

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[1988] ABATE brief, 9
[1989] 8 Tr 5160-5161.
[1990] 8 Tr 5160-5161.

> the amount of that class's overage to the total (similar to the method proposed by Staff initially. . . .[1991]

ABATE finds this alternative approach proposed by Staff is acceptable.[1992]

Noting her agreement with the ABATE's findings that DTE and other utilities have disproportionally benefited from use of the projected test year, as demonstrated by, *inter alia*, excessive level of earnings above the authorized ROE, the Attorney General supports ABATE's proposed earnings sharing mechanism as a "commonsense method to curtail the degree to which DTE can earn over its authorized rate of return on equity due to its projected test year and a way to protect customers."[1993]

For its part, on rebuttal, DTE opposes the imposition of ABATE's earnings sharing mechanism. As Ms. Crozier states:

> If an earnings sharing mechanism is considered, it should be evaluated as part of a broader performance based ratemaking conversation. The time, analysis and context needed to properly consider such a mechanism is not afforded within the bounds of the rebuttal period of a rate case. This proposal should be denied, at best, as premature.[1994]

In response to Ms. Crozier's assertions above, ABATE notes that Northern States Power Company recently agreed to a mechanism in settling Case No. U-21097. As such, ABATE argues that Ms. Crozier's claim that an earnings sharing mechanism "should be evaluated as part of a broader performance based ratemaking conversation" is an "overstated attempt to waylay a mechanism already accepted by another Michigan utility".[1995] ABATE adds that consideration of the mechanism is "not premature", noting that a potential structure for this mechanism has already been outlined in this case by

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[1991] Staff brief, 260, quoting Exhibit AB-35, pages 4-6.
[1992] ABATE brief, 8-9, citing Exhibit AB-35 at 5-7.
[1993] Attorney General brief, 11-12.
[1994] 7 Tr 2387; Exhibit A-23, Schedule M1.
[1995] ABATE brief, 7, quoting 7 Tr 2351-2352.

ABATE and Staff.[1996] Similarly, the Attorney General asserts in its reply brief that DTE's argument "rings hollow," arguing that "[e]very rate case put forth by DTE is littered with new projects, programs, and spending proposals that the Company expects Staff, Intervenors, and the Commission to review and analyze in mere months."[1997]

This PFD agrees that the record in this case does not include an appropriate analysis regarding the recommended imposition of an earnings sharing mechanism. ABATE's proposal for the mechanism was first raised in its initial testimony, which included only a cursory discussion of the asserted basis for the earnings sharing mechanism and a brief explanation of how this specific mechanism might work. The only other testimony offered regarding the proposed mechanism was Mr. Revere's rebuttal testimony, which also stated that Staff does not take a position on the mechanism itself, but that Staff does oppose ABATE's proposed refund method. Thereafter, in its initial brief, Staff changed its position on its suggested refund method, proposing a second, "more appropriate" alternative refund method. No other testimony was offered regarding why the specific earnings sharing mechanism as proposed was appropriate and reasonable, the pro's and cons of this specific mechanism versus a different earnings sharing mechanism, nor providing any sample calculations of potential refunds using prior actual earnings data compared to authorized rates of return.

ABATE's reliance on the Commission's prior approval of an earnings sharing mechanism for Northern States Power Company pursuant to a settlement agreement

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[1996] ABATE reply, 8.
[1997] Attorney General reply, 45.

approved in Case No. U-21097 does not support adopting earnings sharing mechanism on the record in this case. In that prior case, there was no testimony submitted by any party regarding the propriety of the mechanism, nor how the mechanism would work or how any refunds would be paid thereunder. As such, in that case, there was no analysis of the proposed earnings sharing mechanism for the Commission to assess. Thus, there were no findings made or holdings issued in that case that might inform any finding made by the Commission in this case.

This PFD concludes that, while an earnings sharing mechanism may be incorporated in a well-defined performance-based ratemaking proposal, it is not the appropriate means to deal with the underlying concerns with DTE's presentation of projects in rate cases that are in preliminary stages or to which the company has no real commitment. This PFD notes that the Commission has reopened its filing requirements docket, and recommends that the Commission carefully consider requirements that will provide better information regarding DTE's projected expenditures in its filings, and facilitate more effective review by Staff and the parties. This PFD also notes its further recommendation that the Commission scrutinize and address DTE's capitalization policies, recognizing the company's incentive to capitalize rather than expense costs between rate cases, if not more broadly to increase its rate base. But an earnings sharing mechanism of the nature proposed here—well it may limit the company's excess earnings to some extent—will not rein in spending. If anything, the incentive to return money not spent will motivate additional spending, which as this rate case shows, is not necessarily reasonable and prudent, and when capitalized, can lead to significant additional future expenses for ratepayers.

Accordingly, this PFD does not recommend that the Commission adopt an earnings sharing mechanism.

C. Accounting

1. Capitalization Issues

Staff and MNSC raised concerns with DTE's capitalization policies, including capitalization of distribution system and IT expenses. As discussed above, the testimony of the witnesses explaining concerns with DTE's choices over what to capitalize and what to expense is persuasive that the Commission should investigate these matters expeditiously. Staff argues that the Commission should order DTE to revise its capitalization of certain expenses. Staff also argues that the Commission should require DTE to report on its capitalization policies in its next case. This PFD recommends that the Commission open an investigation separate from ongoing rate cases, with the expectation it would provide further direction to DTE at the conclusion of its investigation regarding historic and future expenditures.

2. Low Income credits

As discussed above, it appears that Staff and DTE agree that DTE's deferred asset and liability balances authorized in Case No. U-20561 for LIA and RIA credits above projected levels--and subject to the caps provided--can be addressed in rate cases rather than in biennial reconciliations.

3. Outage Credits

DTE seeks deferred accounting for outage credits. Ms. Crozier explained the company's request:

> The Company is proposing to defer for subsequent recovery, the costs of the customer outage credits that it pays starting with the final order in this

> case. With the Commission's approval, the Company will defer the costs only for those customer outage credits due to outages shown not to be the company's responsibility. Examples of outages outside the compan[y's] control are trees falling from outside of the right of way; public interference, such as a vehicle damaging a pole and causing a service interruption; damage caused by animals, or outages caused by the transmission system operator. Those deferred amounts would be reviewed for reasonableness and prudency in the subsequent general electric rate case. Only after the deferred amounts are approved would the Company begin amortizing and recovering them.[1998]

Ms. Uzenksi also explained the requested accounting.[1999]

Kroger argues that DTE should not recover the outage credits. Mr. Bieber explained:

> Allowing DTE to defer costs for customer outage credits when it fails to restore service within a specified time period, even if the cause of the outage was not DTE's responsibility, reduces the Company's incentive to quickly restore service to its customers. Further, the applicable rules provide significant flexibility for DTE to reasonably request a waiver for its obligation to provide customer outage credits due to circumstances beyond its control.[2000]

Staff agrees with the proposed accounting, but does not have the same standard of company responsibility. Mr. Evans explained Staff's recommendation:

> Staff proposes that the Company recover from ratepayers only those outage credits that are paid out due to outages that are outside the control of the Company to resolve and those caused by customer negligence. An example of an outage outside the control of the Company to resolve would be an outage caused by the transmission system operator. An example of an outage caused by customer negligence would be an outage that occurs due to a customer failing to keep vegetation away from the service line crossing his or her property.
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> However, under Staff's preliminary proposal, credits paid out due to 2 events such as a car hitting a DTE Electric-owned pole or an animal damaging equipment could not be recovered from ratepayers, because restoring customers in a timely manner after car-pole accidents or animal

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[1998] 7 Tr 2361.
[1999] 7 Tr 2270-2272.
[2000] 8 Tr 4645-4646; also see 8 Tr 4647-4651.

> interference is an expected utility function. Staff anticipates that most outage credits paid out after a storm would also not be recoverable, because restoring customers after storms is an expected utility function.[2001]

In rebuttal, Ms. Crozier addressed Mr. Bieber's testimony, asserting that DTE is dedicated to restoring customer service, and further noting that the company has an incentive to restore service because it does not recover volumetric charges from customers who are out of service.[2002] She also testified that the outage credit is not a "penalty."[2003]

Kroger argues the Commission should not permit recovery of the outage credits, citing Mr. Bieber's testimony. Staff argues in its brief that the Commission should adopt Mr. Evans's proposal, which it characterizes as "preliminary," which this PFD understands means that Staff is willing to revisit the issue in a future case. In its briefs, DTE relies on Ms. Crozier's testimony, and does not object to Staff's proposal.[2004]

This PFD finds Staff's proposal is reasonable. It allows the Commission to review the deferred accounting and make a determination based on actual circumstances. This PFD further recommends that DTE be directed to work with Staff on record keeping that will facilitate this review.

2001 8 Tr 5438-5437.
2002 7 Tr 2380.
2003 7 Tr 2381.
2004 DTE brief, 224-225; reply brief, 164.

X.

COST OF SERVICE

A. Production Cost

Several witnesses addressed the allocation of production costs. Mr. Maroun explained that DTE used the established 4CP 75-0-25 method. The Attorney General recommends a revision based on the analysis presented by Dr. Dismukes that would change the weightings from 75% to 55% and from 25% to 45%. Ms. Perry testified that if the production cost allocation method is to change, the Commission should use an "average and excess" or A&E method, which she described in her testimony. In rebuttal, Staff witness Gottschalk and DTE witnesses Mr. Maroun and Ms. Ashgar objected to changing the weightings based on the Attorney General's analysis. Mr. Gottschalk also objected to the A&E method. In their briefs, DTE, Staff, ABATE, and Walmart cite Commission cases rejected the Attorney General's analysis, and they argue that the Attorney General has not presented anything new in this case.

Although MNSC's witness Mr. Jester proposed a modification of the weightings based on a comparison of the capacity cost revenue requirement to total production costs, MNSC does not pursue this modification in its brief. Instead, MNSC focuses on a narrower recommendation also made by Mr. Jester, that took issue with the classification and allocation of MERC and labor-related fuel-handing costs as production plant allocated using the 4CP 75-0-25 allocation method, and concluded that these costs should be considered fuel costs and allocated accordingly. Mr. Jester explained that in Case No. U-20561, the Commission required DTE to produce plant-specific costs in this case, its next rate case. While Mr. Jester perceived some errors in that study,

Exhibit A-32, which he discussed,[2005] he also recommended that the Commission determine that MERC "is a fuel cost for purposes of the unbundled cost of service study and direct that the unbundled cost of service study be corrected in this regard."[2006] He also recommended that all O&M costs for fuel handling be considered fuel costs.

Mr. Maroun objected to this categorization in his rebuttal testimony. He labeled the proposed change "not appropriate," asserting that the Commission has treated MERC-related plant costs in the same manner as production costs since at least the company's rate case, Case No. U-15244, which was resolved in 2008.[2007] He also cited the Commission's order in Case No. U-18248, addressing the capacity charge calculation. He contended that the treatment of MERC as a capacity resource was determined in Case No. U-18248, and further, that it "makes little sense to allocate MERC plant costs like fixed demand costs in the COSS . . . and then deduct it like variable fuel in the capacity charge calculation . . . because then cost allocation will not be in alignment with cost recovery."[2008] He similarly objected to treating the labor component of fuel-handling costs as fuel-related rather than production-related, citing his direct testimony at 7 Tr 1045, where he states that he included only the non-labor portions of FERC accounts 501 (Fuel Handling), 502 (Steam Expenses), 505 (Electric Operations Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expense), and 548 (Peaker Expense) for variable O&M as non-capacity related in his capacity cost revenue requirement calculation. In his direct testimony, he further cited the NARUC Manual:

[2005] 8 Tr 3841-3846.
[2006] 8 Tr 3846.
[2007] 6 Tr 1055.
[2008] 6 Tr 1055.

> The NARUC Manual describes the classification of production plant in Chapter 4. Chapter 4 describes that accounts 502, 505, 519 and 538 should be: Classified between demand and energy based on labor expenses and materials expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related. Therefore, I determined only the material related costs are variable, and that account 501 and 548 should be handled in the same manner. On page 35 in Chapter 4, the NARUC Manual states:
>
>> Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes, and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered, or purchased and are classified as energy related.[2009]

As noted above, Mr. Maroun was also cross-examined on his testimony.

In its brief, MNSC argues that the MERC plant and the labor portion of fuel-handling O&M should be allocated as fuel costs. MNSC argues that the Commission has not addressed these costs before, and that treating them as fuel better reflects cost causation because MERC is a fuel-handling facility, not a generating plant. MNSC cites Mr. Maroun's testimony on cross-examination, acknowledging that MERC does not generate electricity and does not provide DTE with capacity revenue.[2010] Focusing on the objections Mr. Maroun raised in his rebuttal testimony, MNSC explained that DTE did not break out MERC costs until this case. It notes a reference to MERC in the Commission's order in Case No. U-18248, indicating that in that case, DTE witness Mr. Lacey agreed that MERC should be excluded from the capacity cost calculation. MNSC also cites the Commission's September 17, 1976 order in Case No. U-5041, to show

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[2009] 6 Tr 1045.
[2010] MNSC brief, 96.

that MERC was intended to provide fuel savings. MNSC argues that the NARUC Manual, which is included in the record in Exhibit A-39, supports the energy classification of costs such as MERC targeted a fuel-cost savings. MNSC also notes that on cross-examination, Mr. Maroun did not know how MERC was sized; MNSC argues that since the Wisconsin facility serves other customers, it could not plausibly have been designed to meet DTE's summer peak. Regarding the labor component of fuel-handling expense, MNSC argues that the NARUC Manual again supports treating these costs as fuel-related costs, noting that the manual explicitly addresses FERC Account 501, which is at issue here. It notes that rather than following the NARUC Manual, Mr. Maroun determined on his own to consider the labor portion of Account 501 costs as capacity related production costs, as shown in the passage quoted above.

In its brief, DTE relies on Mr. Maroun's rebuttal testimony. In its reply brief, it focuses on MNSC's reference to the Commission's November 21, 2017 order in Case No. U-18248, contending that the Commission previously rejected MNSC's claims in the context of determining the capacity costs.[2011] DTE argues:

> MNSC never disputes that the MPSC has approved rates that include the MERC allocation in every case since U-15244. MNSC implies that the MPSC's consistent allocation treatment regarding MERC is of no import because: first, as to the treatment of MERC costs since DTE Electric's U-15244 rate case, the January 13, 2009 Commission Order in that case never discusses the assignment or allocation of MERC costs, nor does the allocation of MERC costs appear anywhere in the cost-of-service exhibit DTE filed in U-15244. This simple observation by MNSC, that MERC costs are not specifically addressed in the order or appear explicitly on an exhibit does not mean the Commission was unaware of their inclusion or how they were allocated, which both appear in the supporting workpapers submitted with the Company's underlying rate case filings. Commission

[2011] It is clear from a review of that order only that both Staff and DTE did not believe MERC costs should be considered as capacity-related production costs. See November 17, 2021 order, pages 17, 33.

> intention and awareness is also demonstrated in MNSC's Initial Brief p. 98, citing the Case No. U-18248 November 21, 2017 Order which reflects a discussion of MERC costs163 and their allocation in the capacity charge calculation.
>
> Even assuming any merit in any other points (which there is not, but the Company declines to recount history or otherwise burden the discussion), MNSC's proposals would still be wrong and should be rejected under any realistic view of the overall picture. See also ABATE's Initial Brief, pp 19-31.[2012]

No other party took issue with MNSC's recommendations. Although DTE cites ABATE's brief at pages 19-31, in those pages, ABATE explained its objection to Mr. Jester's proposed revision to the production cost allocation method, which MNSC did not pursue as explained above, and did not address MERC or labor portion of fuel-handling expense. This PFD finds that MNSC's recommendation is reasonable, consistent with the NARUC Manual, and not contrary to any specific instructions the Commission has provided. This PFD notes that DTE's contention that the Commission was aware of the company's cost allocation choices based on "workpapers submitted" with rate case filings is not sufficient to establish that the Commission has considered the appropriate classification and allocation of these costs.

Regarding the Attorney General's recommendation, this PFD does agree with the parties to this case that this recommendation has been rejected in several recent cases. Other than pointing out an error in the PFD issued in Case No. U-20561, this PFD agrees that the Attorney General did not present new evidence. This PFD notes that the allocation of production costs is of continuing interest to the parties, and is difficult to evaluate in the context of 10-month rate cases. This PFD recommends that the

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[2012] DTE reply, 172-173.

Commission consider a stand-alone case to investigate whether any change to the method should be considered, after DTE's upcoming IRP case is resolved, when the company's plans to meet capacity and energy needs going forward should be generally understood.

B. Loss Factors

DTE witness Mr. Robinson explained DTE's line loss study prepared in response to the Commission's order in Case No. U-20561 and included in Exhibit A-28. He explained that DTE commissioned an engineering firm, Burns and McDonnell, to perform the study, and explained the study methodology, including a description of the system components. He explained that the company's marginal line loss study did not evaluate all the specific recommendations included in the Commission's order, but explained the significant additional time and resources that would have been required.[2013]

ABATE rejects the demand line loss factors resulting from the study, arguing that it wrongly produced line loss factors reflecting average demand for each month, as well as at the single annual system peak. Citing Mr. Andrews' testimony, ABATE argues that the line loss factors Mr. Andrews estimated in Exhibit AB-4 should be used instead, to reflect line losses at monthly peak demand.[2014] Mr. Andrews testified that line losses are greater at the monthly peak demand than on average, and thus the average line loss factors will understate the generation necessary to supply lower-voltage customers at

[2013] 7 Tr 1566-1569.
[2014] ABATE brief, 31-37.

peak periods, and in particular the 4 monthly peaks used to determine the 4CP production allocation. ABATE also cites Mr. Bieber's testimony at 7 Tr 4669-4673.

Mr. Andrews explained his calculation of the line loss factors in Exhibit AB-4:

> We know that as load increases, losses increase and vice versa. By using the relationship between the peak and average scenarios, the loss factors that would exist during demands at the 4CP can be estimated. For example, as shown in Figure 1 above, the 2019 Line Loss study shows that during peak conditions, secondary customers have cumulative line losses of 17.173%, but during average conditions, those cumulative losses decrease to 9.065%. That decrease in the cumulative line loss factor is 47.2%. At the same time total system sales decreased from 9,498 MW on peak to 5,300 MW during average a decrease of 44.2%. DTE's 2019 sales at the time of its 4CP was 8,977 MW, which is a 5.5% reduction relative to peak load. Using that relationship, one can calculate a 4CP loss factor for secondary distribution of 16.17%. In Exhibit [AB-4], I provide the calculations for the loss factors for all voltage levels using this same methodology.[2015]

He also performed this same calculation for the loss factors used in the 12 CP allocator calculation. Kroger also argues that the Commission should accept ABATE's demand allocation factors.

DTE and Staff object. Mr. Gottschalk's rebuttal testimony asserted that Mr. Andrews made contradictory statements about the feasibility of estimating peak line losses from the average line loss study results, contrasting Mr. Andrews' statement that "line loss factors based on average loading conditions cannot be used to estimate line losses that occur during times of peak demand," and then arguing that line loss factors at the 4CP times can be estimated.[2016] He also testified that this analysis effectively assumed a linear relationship. Mr. Gottschalk recommended that the estimated factors not be used. Ms. Ashgar testified that DTE does not support using the line loss factors

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[2015] 8 Tr 2990-2991.
[2016] 8 Tr 5120.

estimated by Mr. Andrews "since they have not been reviewed and are based on incomplete system information."[2017] She also testified that DTE would consider exploring a revised method for calculating line loss factors in the future.

In its brief, Staff argues that the Commission should not adopt ABATE's recommendation, citing Mr. Gottschalk's testimony.[2018] DTE argues that the Commission should not adopt ABATE's recommendation, citing Ms. Ashgar's testimony.[2019]

ABATE argues in its reply brief that the line loss factors used in DTE's cost of service study "do not ensure rates equal to the cost of service."[2020] ABATE contends:

> [B]oth DTE and Staff themselves respectively confirmed and did not disagree with the underlying premise of ABATE's proposal, that line losses during peak system conditions are greater than line losses during average system demand conditions. . . . As such ABATE's proposal is more consistent with the manner in which DTE incurs and allocates these costs and better ensures rates equal to cost of service.[2021]

This PFD finds that ABATE's recommendations should be rejected. It has not validated Mr. Andrews' estimates over any period of time. Both Staff and DTE express skepticism that these estimates are valid or have been validated. ABATE is clearly wrong in contending that a potential understatement of line losses at peak time justifies any estimate to adjust for that understatement. Mr. Robertson described the complexity in determining marginal line losses. It is also questionable whether the precision that ABATE is seeking is attainable, what the potential error range is, and whether it is consistent with the rationale underlying the use of 4CP.

[2017] 7 Tr 1465.
[2018] Staff brief, 269.
[2019] DTE reply, 165.
[2020] ABATE reply, 4-6.
[2021] ABATE reply, 5, also citing Bieber, 8 Tr 4669-46673.

C. Capacity Charge Revenue Requirement

Mr. Maroun presented DTE's proposed calculation of the State Reliability Mechanism (SRM) capacity charge revenue requirement, presented in Schedule F1.5 of Exhibit A-16.[2022] He testified that the calculated the capacity-related power supply as determined in prior cases,[2023] starting with all production-related costs and subtracting fuel, variable O&M, and certain purchased power costs.[2024] He also testified that he used the same methodology to calculate energy sales revenue net of fuel costs "as approved by the Commission in its May 8, 2020 Order in Case No. U-20561."[2025] He then testified that his calculations in Exhibit A-16, Schedule F1.5 includes "a reduction in revenue requirement for projected energy sales revenue net of fuel-related costs, calculated by Witness Burgdorf on Exhibit A-26 Revised, Schedule P3."[2026]

Mr. Gottschalk testified that DTE did not follow the Commission approved method to determine the capacity revenue requirement.[2027] He explained that DTE "inappropriately included MISO Schedule 17 Market Administrative Costs as a fuel cost that offsets projected energy sales revenue." He quoted the Commission's May 2, 2019 order in Case No. U-20162 as follows:

> Finding that the utility provided no convincing argument otherwise, the Commission also agrees with the Staff and the ALJ that MISO Schedule 17 administrative costs should not be subtracted from projected energy sales revenue. (MPSC Case No. U-20162. May 2nd, 2019 Order. p.132.)

He presented a corrected calculation in Exhibit S-6, Schedule F1.5 of $1,538,293,000.

[2022] 6 Tr 1028, 1043-1046.
[2023] 6 Tr 1028, 1043.
[2024] 6 Tr 1043.
[2025] 6 Tr 1043.
[2026] 4 Tr 1043-1044.
[2027] 8 Tr 5109-5110.

Mr. Zakem also objected to DTE's calculation of the capacity revenue requirement, focusing in part on the statutory language of MCL 460.6w, which directs the subtraction of certain sales revenue "net of fuel costs," rather than "fuel-related costs" as a step in the capacity revenue requirement calculation. He objected to DTE's subtraction of "emission allowances, chemicals, and MISO market administration" rather than fuel costs only, also citing the Commission's order in case No. U-18248.[2028]

In addition, Mr. Zakem urged the Commission to require greater documentation of the approved methodology and transparency in filed capacity charge calculations, so that all components are clearly stated with sources identified.[2029] He also expressed a concern with the true-up mechanism, citing the language of MCL 460.6w(4) and explaining:

> Operationally, the language has little meaning. First, there are no "actual net revenues reflected in the capacity charge" -- only "projected" net revenues -- so a difference between projected and actual does not make sense. Second, the language ignores the situation that no party is assessed the SRM Capacity Charge, yet implies the utility still has to apply a true-up charge to someone or refund a true-up credit to someone. If no one has been charged the SRM Capacity Charge, there is nothing to "true up." Third, if a party is assessed the SRM Capacity Charge in one year but not the next, how does that party receive the true-up charge or credit since the true-up supposedly applies to the subsequent year via the SRM Capacity Charge?[2030]

While acknowledging the apparent intent of the true up language that the utility and anyone paying the charge not be at risk to estimates but rather only pay for actual costs

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[2028] 8 Tr 4505.
[2029] 8 Tr 4503-4504, 4512-4514.
[2030] 8 Tr 4506.

when they become known,[2031] he considered the rolling true-up inequitable applied to those who did not pay the charge being reconciled:

> DTE has not charged anyone the SRM Capacity Charge. Therefore it is not short of any money, nor does it owe any money, that has to be "trued-up." Further, any party that would be charged the new SRM Capacity Charge would be paying for DTE's previous estimates of energy sales and fuel that were above previous actuals -- a discrepancy that has nothing to do with future capacity costs.[2032]

In the course of his discussion, Mr. Zakem referred to DTE’s true up of the 2019 costs used in setting the last capacity charge to 2020 as an error. DTE and Staff thus addressed this aspect of his proposal in rebuttal. Mr. Zakem also presented a calculation of the SRM capacity charge in Exhibit EM-6, using the MW value from DTE’s lates SEC Form 10-K for 2021 of 12,524 MW, noting that no party had put this value in the record. He provided a revised version that incorporated Staff’s revenue requirement, fuel cost and variable O&M values in his rebuttal exhibit, Exhibit EM-7.

Mr. Maroun presented rebuttal testimony, but did not acknowledge Mr. Gottschalk’s testimony. In his rebuttal, Mr. Burgdorf testified explicitly that DTE used the same method in this case as it did in Case No. U-20561 and also disputed that it used a methodology contrary to the Commission’s order in Case No. U-20162:

> Q14. Do you agree with Witness Gottschalk’s claim that (on page 6, lines 11-12) “The Company’s capacity revenue requirement method is not consistent with the method ordered by the Commission in U-20162.”?
>
> A14. No. The methodology of subtracting out the category of “Fuel-Related Costs” from energy revenue sales is consistent with previous cases. Justification and discussion of what specific costs go into Fuel-Related Costs is separate from the calculation method.

[2031] 8 Tr 4506.
[2032] 8 Tr 4510.

> Q15. Do you agree with Witness Gottschalk's claim (on page 6, lines 17-23) the Company's inclusion of MISO Schedule 17 Administrative costs in this case is contrary to the Commission's order in U-20162?
>
> A15. No. As previously discussed, the method of subtracting the category of "Fuel Related Costs" from the energy revenue sales remains the same from Case No. U-20561. The Company recognized that it needed to justify and provide discussion on the inclusion of the Schedule 17 Administrative costs within the Fuel-Related Cost category in Case No. U-20561. These costs were discussed by the Company in Case No. U-20561 without any modification by the Commission and properly included in the approved method of subtracting out Fuel-Related Costs. The Company continues to justify appropriate costs that should be included in the Fuel Related Costs to ensure all customers are treated fairly.[2033]
>
> Q16. Do you agree with Witness Gottschalk's statement position (on page 6, lines 12-14 of direct testimony) that "The Company inappropriately included MISO Schedule 17 Market Administrative Costs as a fuel cost that offsets projected energy sales revenue."?
>
> A16. No. It is proper for the Company to include this cost in the "Fuel-Related Costs" as these costs only occur with the production of energy from the Company's generation assets. This was explained in my Direct Testimony on page 10 lines 24-25 "These expenses need to be included as they would not be incurred if the generation sales did not occur." To give the "benefit" of the energy sales to customers being charged the SRM without including all the attributable costs to produce the energy is not fair to the Company's PSCR customers who would end up paying those extra costs, thus subsidizing customers on the SRM Capacity Charge.
> Staff agrees with Energy Michigan.

Ms. Crozier provided rebuttal testimony addressing Mr. Zakem's true-up concerns, focusing on the statutory language of section 6w: "I am not an attorney and am not offering a legal opinion. However, when I read the quoted language, I do not see the requirement to include a capacity charge true up as being contingent on whether or not an Electric Choice customer paid a capacity charge during the period being

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[2033] 4 Tr 150-151.

reconciled. Therefore, I conclude that the energy sales net of fuel true up must be included in the calculation of the capacity charge."[2034]

In his rebuttal, Mr. Gottschalk addressed Mr. Zakem's testimony regarding the dates of data used in determining the charge and true-up value, explaining that it is appropriate to compare 2020 actuals to projected values from case No. U-20561 because the projected amounts were used to set rates for 2020.[2035]

DTE's brief responded to Staff's testimony, reiterating the gist of Mr. Burgdorf's rebuttal, contending both that "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," and that its approach is necessary "to ensure all customers are treated fairly."[2036] DTE repeats these arguments in its reply brief.[2037]

In its brief, Staff notes the correction that needs to be made to DTE's calculation of the capacity charge revenue requirement.[2038] Staff also reiterates Mr. Gottschalk's explanation for the true-up using the future period costs.[2039]

In its brief, Energy Michigan also takes issue with DTE's claim that its capacity revenue requirement calculation complies with the Commission's prior orders:

> In its Energy Sales Revenue calculation, shown in Exhibit A-26, DTE Electric Company ("DTE") shows a cost of fuel of $1,004,837 (000). This is all well and good and in accordance with Section 6w. However, DTE then adds in what it calls "Fuel Related Generation Expense," which includes "Emission Allowances," "Chemicals," and "MISO Market Administration"

[2034] 7 Tr 2393-2394.
[2035] 8 Tr 5117-5118.
[2036] DTE brief, 240.
[2037] DTE reply, 176.
[2038] Staff brief, 263.
[2039] Staff brief, 269-270.

> on lines 21-23 of Exhibit A-26, Schedule P3.4 These three "fuel-related" costs total $28,415 (000). Their inclusion is not authorized by the statute, which only mentions "projected fuel costs" and makes no reference to any other expenses, whether "fuel-related" or not. The original Commission decision that established an SRM Capacity Charge for DTE's service territory implicitly recognized this, as the netting methodology approved by the Commission in that case, U-18248, included only fuel costs and excluded "fuel-related" costs.[2040]

Energy Michigan acknowledges Mr. Burgdorf's rebuttal testimony that DTE calculated the charge in the same way in Case No. U-20561, but disputes the significance:

> In rebuttal, DTE states, "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 the production of energy from the Company's generation resources." This statement is true as far as it goes—the Commission did approve DTE's proposed capacity revenue requirement that included "fuel-related" costs, but it did not clearly do so for DTE's stated reason, that "these costs are all incurred as a result of the production of energy from the Company's generation resources." In fact, the Commission did not discuss the issue at all or make any ruling on the reason why these costs ended up being included. For its part, DTE gave the Commission no reason [to] dig deeper into its SRM Capacity Charge calculation in that case, since it described its proposed calculation methodology as "[c]onsistent with the methodology used in the Commission's Order in U-20162," and made no mention of the inclusion of "fuel related" costs when describing "the differences between the methodology used in prior cases to calculate the energy market sales net of fuel and the methodology used in this case." Case No. U-20561 is thus best described as an inadvertent outlier among all the cases in which the Commission implemented and updated the SRM Capacity Charges of DTE and Consumers Energy.[2041]

Staff's reply brief endorses Energy Michigan's analysis.[2042]

DTE's claims are puzzling. As Mr. Gottschalk testified, the Commission clearly held that "MISO Schedule 17 administrative costs should not be subtracted from projected energy sales revenue."[2043] It further directed:

[2040] Energy Michigan brief, 2.
[2041] Energy Michigan brief, 2-3;.Staff brief, 269-270.
[2042] Staff reply, 30-31.
[2043] May 2, 2019 order, Case No. U-20162, page 133.

> The Commission thus adopts the Staff's method as applied herein, and the Staff's proposed capacity revenue requirement, which has been adjusted based on the decisions in this order to $1.24 billion. While it is free, of course, to make any argument it wishes, in its next rate case filing *DTE Electric shall provide an updated capacity cost calculation applying the method approved herein*.

As cited by Energy Michigan, Ms. Crozier's testimony in Case No. U-20561 expressly acknowledged the Commission's directive in the prior rate case, i.e. Case No. U-20162, and asserted that DTE was complying:

> Q17. How is the Company calculating its proposed capacity charge?
>
> A17. Similar to prior cases, the Company is calculating its proposed capacity charge by beginning with all production related costs included in DTE Electric's base rates, surcharges and power supply cost recovery cases consistent with PA 341, section 6w (3) (a). Fuel, variable O&M, and non-capacity related purchase power expenses are subtracted from these production costs to produce the fixed capacity related production costs. Consistent with the methodology used in the Commission's Order in U-20162, the Company also subtracts the proceeds of gross energy market sales, net of fuel, from the fixed capacity costs. The gross energy market sales, net of fuel offset being used in this case is the 2019 projected gross energy market sales, net of fuel including a true-up for the 2018 gross energy market sales, net of fuel.
>
> Q18. What are the differences between the methodology used in prior cases to calculate the energy market sales net of fuel and the methodology used in this case?
>
> A18. There are two differences to the proposed energy market sales calculation as compared to prior cases: 1) the energy market sales revenue used is gross energy market sales, not net energy market sales as used in prior cases; and 2) as mentioned above, the projected 2018 gross energy market sales, net of fuel, is being trued-up to actuals with the difference netted against the 2019 projected gross energy market sales, net of fuel for use in calculating the proposed capacity charge.
>
> Q19. Why is the Company using gross energy market sales instead of net energy market sales?
>
> A19. In its order dated May 2, 2019 in Case No. U-20162, the Commission directed the Company to include in its next rate case, a calculation of gross energy market sales, net of fuel for the offset to capacity related

> production costs, not net energy market sales, net of fuel; that is, the Commission rejected the Company's proposed net energy market sales, net of fuel calculation. Therefore, in this case, I have directed Company Witness Mr. Burgdorf to provide the gross energy market sales net of fuel calculation, as ordered, and I have directed Company Witness Mr. Lacey to use that amount in developing the proposed capacity charge revenue requirement that, if approved, would be applicable with a Commission order in this case in 2020.[2044]

As she is in this case, Ms. Crozier was the company's overview witness in Case No. U-20561. So, notwithstanding the Commission's clear directive in U-20162, and Ms. Crozier's clear statement of compliance in Case No. U-20562, DTE's claim that it is using an approved method relies on a non-conforming calculation that somehow evaded review in Case No. U-20561. The company's calculation in this case should be rejected for the reasons explained by Mr. Gottschalk and Mr. Zakem.

Regarding Energy Michigan's true-up concern, DTE argues that equity is not a consideration in statutory construction and relies on the text of MCL 460.6w. Putting aside the contrast between DTE's arguments regarding the interpretation of "fuel" and its interpretation of section 4, Energy Michigan's argument is that DTE's interpretation of MCL 460.6w leads to absurd results. It argues that in every case other than Case No. U-20561, the Commission has not reflected a charge or credit in the forward-looking capacity charge when no AES has paid the capacity charge. While the statute does clearly require a true-up, it is not clear exactly what is supposed to happen under section 4, which 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 subsection (3) and the actual net revenues reflected in the capacity charge. The *true-up shall be reflected in the*

[2044] Case No. U-20561, docket #0386, transcript volume 4, Tr 465-466.

> *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.*

This section requires both a "charge or credit" and some "true-up" reflected in the capacity charge in the subsequent year. Perhaps the "charge or credit" is issued to those who pay the charge, while the "true up" refers to the actual net revenues for the prior year, which then must be reflected in the capacity charge in the subsequent year. Focusing strictly on the text, if the legislature meant only that the "charge or credit" would be reflected in the capacity charge in the subsequent year, it would have been simple for it to say so, instead of using the term "the true-up." This is consistent with Mr. Gottschalk's testimony that the forward-looking charge should be reconciled to the actual results for the period within which it is collected. When DTE has not overcharged or undercharged anyone for capacity costs, there is no charge or credit to issue, but the true-up, i.e. the true-up net revenue, must be used in the mechanism for the subsequent period, using the same methodology.

D. Secondary Volage Distribution Costs

Based on Dr. Dismukes' testimony, the Attorney General argues that the costs associated with demand-related secondary voltage distribution systems based on class non-coincident peak demands. She explains Dr. Dismukes' conclusion that DTE's proposed allocation places too much emphasis on individual customer peak loads, failing to recognize that not all customers present peak demands on the system peak at the same time. Dr. Dismukes also presented an analysis of rate cases to show that DTE's allocation of secondary-voltage distribution costs is inconsistent with the way in which these costs are typically allocated in other jurisdictions.

The Attorney General acknowledges that the Commission rejected this recommendation in Case No. U-20561. DTE argues that the Attorney General has not presented new evidence to support revisiting this issue, but has essentially presented the same analysis.[2045] This PFD agrees, noting the Commission's May 8, 2022 decision in Case No. U-20561, 223-225. Although the Attorney General cites information regarding other jurisdictions, this information appears to have also been presented in Case No. U-20561.

E. <u>Uncollectible Expense Allocation</u>

Mr. Maroun proposed that DTE continue to allocate costs associated with uncollectible expenses by customer class. Mr. Maroun testified that that this method accurately reflects cost causation, as it measures write offs net of recoveries caused by each major class and assigns the uncollectible expense on that basis.[2046] Mr. Maroun explained that this method is consistent with the methodology utilized in the final rates approved by the Commission in Case No. U-20561.[2047]

Staff witness Gottschalk disagreed with DTE's proposed allocation of uncollectible expenses, stating that the company's method does not reflect the reality of why uncollectible costs are incurred or how they should be borne by each customer class.[2048] Mr. Gottschalk presented Staff's recommendation to allocate uncollectibles based upon total revenue, because uncollectible expense should be shared by all customers, which would be consistent with how their overall costs are recovered by the

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[2045] DTE reply, 169-170.
[2046] See 6 Tr 1041
[2047] See 6 Tr 1041
[2048] See 8 Tr 5110.

company.[2049] Mr. Gottschalk further testified that this method is consistent with the uncollectibles allocation method approved by the Commission in U-20963, DTE's last gas rate case.[2050]

In rebuttal, Mr. Maroun disagreed with this proposal, positing that: (1) Staff's proposal to use an overall allocation scheme will result in customer classes being allocated a share of uncollectible expense that is disproportionate to those expenses caused by each class; (2) the Commission has previously held that it is appropriate and consistent with regulatory ratemaking principles to directly assign costs to the class that caused those costs; and (3) as certain classes are responsible for a larger percentage of Net-Write Offs than Total Revenue the costs caused by those classes should be appropriately allocated.[2051] In addition, Mr. Maroun stated that Staff's proposal to allocate uncollectibles was previously made and rejected in Case No. U-18014.[2052]

Staff cites Case No. U-20963 for the proposition that uncollectibles based upon total revenues is the proper method for allocating uncollectible expense.[2053] Commission held:

> The Commission agrees with the ALJ's recommendation to return to allocating uncollectibles based on total revenue, as proposed by the Staff. While the Commission recognizes that this is a departure from the currently approved methodology for Consumers, the Commission finds that the allocation of uncollectibles as a general cost of doing business more accurately reflects both cost-of-service principles and, as the ALJ noted, the approach historically used by utilities.[2054]

[2049] 8 Tr 5111.
[2050] 8 Tr 5111.
[2051] 6 Tr 1067-1068.
[2052] 6 Tr 1066.
[2053] 8 Tr 5111.
[2054] 8 Tr 5111.

The Commission additionally referenced the following:

> Furthermore, the Commission recently reached a similar conclusion and ordered the return to allocating uncollectibles as a general cost of doing business as part of its decision in DTE Gas Company's rate case. See, December 9, 2021 order in Case No. U-20940, pp. 189-190. As noted in that case, "[t]he question of whether to pay–or not to pay–the utility bill rests with the individual customer, not the class in which that customer is situated."[2055]

The arguments offered by Mr. Maroun were also offered in Case No. U-20940 by DTE Gas and rejected by the ALJ as well as by the Commission.[2056] The Commission held:

> The question of whether to pay–or not to pay–the utility bill rests with the individual customer, not the class in which that customer is situated. Because these costs tie much more closely to the company's basic cost of doing business than to the current allocation approach that conflates cost causation with mere class membership the Commission adopts the PFD's allocation of uncollectibles on the Cost of Service plus Cost of Gas allocator.[2057]

In its brief, DTE reiterates that it continues to allocate costs associated with uncollectible expenses by customer class for the reasons already offered. Disagreeing, Staff continues to recommend allocating uncollectibles based on total revenue, or in the alternative, by a three-year average of net write-offs.

This PFD finds the Staff's recommendation to be reasonable and in accordance with recent methods approved by the Commission in cases U-20963 and U-20940. Therefore, Staff's recommendation to allocate uncollectible expense on the basis of total revenue should be adopted.

[2055] December 22, 2021 order, Case No. U-20963, page 354.
[2056] December 9, 2021 order, Case No. U-20940, pages 186-189.
[2057] December 9, 2021 order, Case No. U-20940, pages 189-90.

F. Streetlight Depreciation Expense

Based on Mr. Bunch's testimony, MI MAUI and Ann Arbor argue that DTE's depreciation expense associated with its plant balances for streetlighting is responsible for the significant increase in municipal lighting rates, and further argue that the plant balances on which the depreciation expense is based "fail to reflect the steady transition from HID to LED lighting." One focus of Mr. Bunch's testimony was the decline in the number of HID lights served by overhead wires, relative to the plant in service (PIS) balances for those lights.[2058] MI MAUI and Ann Arbor reject Mr. Bellini's explanation in rebuttal testimony that the removed lights are older and therefore cost less than the replacement lights. They argue that this argument is inconsistent with the group valuation approach that DTE takes to lighting, and does not explain why the overhead HID plant balances have fallen significantly less than the underground balances.[2059] MI MAUI and Ann Arbor conclude that DTE is overvaluing the assets in HID subaccount, and this overvaluation is leading to increased depreciation expense. MI MAUI and Ann Arbor present a chart in their brief at page 57 to show the changes in plant balances for HID luminaires from 2018 to the projected 2023 level; this chart shows luminaire counts falling by 43%, but per luminaire plant balances increasing by 46%.

MI MAUI and Ann Arbor argue that the increases are attributable to DTE's allocation of projected capital expenditures ratably across all streetlighting subaccounts:

> The Company projects that its overall streetlighting PIS will increase 14.9% through the test year – an amount we dispute below – and allocates the same 14.9% increase to each 373 subaccount. This methodology is inaccurate when one asset type (HID luminaires in

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[2058] 8 Tr 3443.
[2059] MI MAUI brief, 55-56.

> accounts 373.05 and .07) is shrinking and being replaced by another asset type (LED luminaires in accounts 373.06 and .08), and those replacement assets come with a significant customer CIAC.[2060]

In notes Mr. Maroun's rebuttal testimony agreeing to work with Staff to align the capital allocations more accurately with the company's investment plans, and indicates it will be happy to participate in the discussions,[2061] further stating an expectation that those discussions could result in more accurate allocation of costs in this case. As an alternative, recognizing that is not possible, MI MAUI and Ann Arbor ask that the Commission "order the Company to calculate test year depreciation expense for HID luminaire subaccounts using the Company's projected HID luminaire counts and the 2018 PIS balances as a baseline as proposed by Mr. Bunch. MI MAUI and Ann Arbor argue their proposal will reduce test year depreciation expense by $1.6 million or approximately $30 per HID luminaire, based on plant values as of 2018. They conclude that:

> If that result means customers whose plant in service is growing in size pay more in depreciation for that property than customers whose plant in service is decreasing in size (in large part because those customers are paying for more assets up front), that seems altogether appropriate, prudent, and reasonable.[2062]

It is this last statement that has caused Staff significant concern. Citing Mr. Revere's rebuttal testimony at 8 Tr 5162, Staff argues in its brief that MI MAUI proposals that would result in customers bearing costs they are not responsible for should be

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[2060] MI MAUI brief, 58.
[2061] MI MAUI brief, 59.
[2062] MI MAUI brief, 60.

rejected.[2063] MI MAUI and Ann Arbor respond in their reply brief that they do not advocate increasing depreciation costs allocated to other customers.[2064]

DTE relies on Mr. Bellini's testimony at 7 Tr 1744-1747 and Mr. Maroun's testimony at 6 Tr 1061-1065 to address MI MAUI and Ann Arbor's concerns with the plant balances and resulting depreciation expense.

This PFD finds that DTE's plant balances are of concern, and finds that DTE has recognized this in part, as evidenced by Mr. Maroun's rebuttal testimony. As discussed in the rate base section of this PFD, there are reasons to question the reasonableness and prudence of DTE's capital investments. Although this PFD calls for further study and does not find a basis on this record for capital disallowances, that finding is without prejudice to future determinations, on further evaluation, that DTE's decision-making regarding its lamp choices or other capital expenditures in this program area have been unreasonable or imprudent and should be disallowed. A review of the plant balances is preferable to a limitation on depreciation expense, which does not get to the ultimate question of the reasonableness of those plant balances. DTE's plant balances will reflect numerous capital or asserted capital expenditures that cannot be reviewed on this record, not only the lamp purchases that Mr. Bunch focused on. The other piece of depreciation expense, of course, is the depreciation rate. MI MAUI and Ann Arbor should continue to work with DTE and Staff to confirm the accuracy of the plant balances based on capital investments and appropriate allocations of those investments to the different lighting accounts. Given the substantial shift in asset purchases to LEDs,

[2063] Staff brief, 261-262.
[2064] MI MAUI reply, 23.

the Commission may also want to consider requiring DTE to file a new depreciation case sooner than the 2024 date in the settlement agreement discussed above. With the significant turnover in lighting assets in this category, and the increase in LED lighting, a depreciation case review should provide greater transparency into the longevity of these assets. That said, depreciation expense is tracked and will reduce plant balances over time; the depreciation reserve reduces the rate base to which a rate of return is applied in determining revenue requirements, so the value of the additional revenues paid to DTE to cover depreciation expense will be preserved through this process.

XI.

RATE DESIGN AND TARIFFS

A. Residential

1. Time of Use (TOU) residential rates

In its May 2, 2019 order in Case No. U-20162, the Commission explained the history of its requirement for DTE to propose summer on-peak and off-peak rates:

> In the 2018 orders [in Case No. U-18255], the Commission directed DTE Electric, in its next general rate case, to file tariffs reflecting the elimination of the summer monthly block rate and its replacement with a summer on-peak/off-peak rate, and a proposal for allowing customers who opt out of AMI to retain the existing rate structure. On rehearing, the Commission recognized this as being a significant change and clarified that this decision did not foreclose consideration of implementation issues concerning timing or costs in a future rate case. In this current rate case, the company made the required filing, proposing a rate structure and an implementation plan, with associated costs.[2065]

After concluding that DTE had complied with the Commission's requirements in its filing in that case, the Commission turned its attention to DTE's request that the Commission reverse its prior directive:

[2065] May 2, 2019 order, page 152.

> DTE Electric requested that the Commission (1) allow the company to retain its existing Rate D1 pricing schedule, as opposed to requiring DTE Electric to convert the non-capacity charge of its default residential rate to a TOU rate structure (i.e., summer on-peak rate), and (2) allow customers to retain the ability to voluntarily opt into various TOU rate products the company currently has available. Id., pp. 83-85. If the Commission does not reverse its prior directive, however, DTE Electric claimed that it must be permitted to move forward with implementing this new, Commission-ordered Rate D1 pricing schedule over a reasonable time period and with all implementation costs being recoverable. 3 Tr 85.[2066]

The Attorney General supported DTE's request in that case, expressing a concern that the switch to time-of-use rates would harm residential customers, especially senior citizens on fixed incomes and small business, if they were forced into this rate schedule.[2067] Staff disputed the concern, but offered an opt-out tariff as an alternative.[2068] In addition to Staff, MEC/NRDC/SC also opposed reconsideration. The Commission upheld its decision in its 2018 orders in Case No. U-18255 "to ultimately move toward summer on-peak rates," but altered the implementation schedule and approach "to allow for piloting of concepts as well as system development to support a smooth and cost-effective transition."[2069]

The Commission reviewed DTE's cost estimates to implement the new rate structure:

> To implement this new rate structure, DTE Electric estimated that it would cost: (1) $23 million for IT costs (for system redesign and programming), spanning 22 months; (2) $9.3 million in marketing and advertising costs during the first year the rate is implemented; and (3) $12 million for operational customer service costs also during the implementation year, with ongoing annual expenses of approximately $4 million thereafter. 5 Tr 1393-1395; 6 Tr 2106-2107; 7 Tr 3133-3136. With these estimated O&M costs, the company requested authorization to defer treatment and

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[2066] May 2, 2022 order, page 152.
[2067] May 2, 2019 order, page 153.
[2068] May 2, 2019 order, page 153.
[2069] May 2, 2019 order, page 154.

> recovery of the one-time operating expenses, not to exceed $45 million (unless the IT costs are capitalized, then approximately $22 million). 7 Tr 3339.[2070]

Although the ALJ in that case recommended approval of DTE's request to defer and amortize the O&M expenses, not to exceed $45 million, the Commission disagreed:

> While the Commission anticipated a proposal on this new D1 rate structure to include some implementation costs, DTE Electric's cost proposal lacks detail and is not adequately supported. The Commission seeks a more measured (i.e., less exorbitant) approach than that provided by the company in this case, and one that provides justification for the costs. The Commission therefore declines to authorize DTE Electric's regulatory asset treatment request at this time and looks to review more refined (and more vetted) implementation costs, including costs in the test year, in the company's next rate case, wherein the Commission directs DTE Electric to file a new proposal in line with the decisions below regarding the rate structure and implementation plan.[2071]

The Commission then discussed the rate structure, describing DTE's proposal to establish summer on-peak and off-peak rates with a peak period of 4:00 pm to 9:00 p.m. weekdays, from June to September, with a $0.01 per kWh cost differential that DTE represented was cost-based.[2072] As described by the Commission, Staff and DTE agreed that the capacity rate would not vary between summer on-peak and off-peak periods. As described in that order, Staff and MEC/NRDC/SC initially recommended applying the same differential to capacity rates, but DTE argued that their recommendation did not comply with the Commission's prior orders in Case No. U-18255.[2073]

An issue that required Commission resolution related to the ALJ's recommendation that the Commission continue to explore the Staff and MEC/NRDC/SC

[20702070] May 2, 2018 order, pages 154-155.
[2071] May 2, 2019 order, page 155.
[2072] May 2, 2019 order, page 156.
[2073] May 2, 2019 order, page 156.

initial recommendation to include a differential capacity rate in a future rate case. DTE objected, as the Commission explained:

> The company questions the benefit of this recommendation, given the ALJ's rejection of the same as not comporting with the 2018 orders and the fact that DTE Electric will not have conducted an impact study of customers' reactions to this new pricing structure. The company further objects to this recommendation to the extent it places an initial burden on it "of either presenting evidence or proof on another party's flawed and rejected proposal." DTE Electric's exceptions, p. 124.[2074]

Staff presented its initial recommendation, urging the Commission to include a capacity differential:

> The Staff conversely asserts that the Commission should approve its proposed summer on-peak differential for non-capacity charges and to also apply the changes to the capacity portion. Contrary to the ALJ's reasoning about possible adverse outcomes of using its proposed price differential for the summer on-peak rate, the Staff argues that the ALJ "fail[ed] to consider Staff's argument and supporting evidence (including Company testimony) that projected shifts in usage and revenue fall outside of the test period in the instant case per both proposed implementation plans, and therefore have no bearing on the appropriateness of the change." Staff's exceptions, pp. 9-10. The Staff further asserts that the ALJ also failed to consider its evidence as to the appropriateness of its proposal to apply the on-peak differential to capacity rates, "as '[i]t is appropriate to charge more during summer on-peak hours for capacity, as this is when the capacity need is set.'" Id., p. 10 (alteration in original).[2075]

MEC/NRDC/SC also took exception to the ALJ's recommendation, "urg[ing] the Commission to disagree with the ALJ, otherwise leave the inverted block rate in place in this case, and then require DTE Electric to apply the summer on-peak rate to capacity charges in its next rate case." The Commission quoted MEC/NRDC/SC's exceptions:

> This is consistent with cost of service and more equitable to ratepayers. The main argument that has been raised against this change -- that it

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[2074] May 2, 2019 order, page 157.
[2075] May 2, 2019 order, page 157.

> would require time and education to prepare customers -- is unavailing because there is time, piloting, and education built into the implementation plan for non-capacity summer on-peak rates to also accommodate summer on-peak capacity charges.[2076]

MEC/NRDC/SC also asked the Commission to approve Staff's price differentials. The Commission order also explains that the RCG recommended that the differential between on-peak and off-peak charges be minimized "because this is the first case where this rate structure may be imposed and rate shock to residential customers should be considered."[2077]

The Commission explained its conclusion before setting an implementation schedule:

> The Commission agrees with the ALJ that the pricing differential proposed by DTE Electric for the non-capacity rates is reasonable and cost-based. At this time, the Commission is not compelled to move forward with the pricing differentials proposed by the Staff given the potential impacts on certain customer segments. 8 Tr 3865, 3884. With respect to the non-capacity rates, the Commission is concerned with abrupt shifts in the overall rate design absent additional testing and customer education through pilots. Therefore, the Commission expects that the on-peak capacity (and non-capacity) rates should be tested as a combination but is concerned with establishing this as the default rate. The on-peak rates will be implemented through pilots in accordance with the implementation plan discussed below.[2078]

In setting the implementation schedule, the Commission reviewed DTE's recommended proposal and its alternative proposal. The ALJ recommended adoption of the alternative plan, which Staff and MEC/NRDC/SC supported, but the Commission disagreed and adopted DTE's preferred plan, which called for piloting multiple rates "to allow for a more comprehensive assessment potential rate designs . . . [and] testing multiple

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[2076] May 2, 2019 order, page 158, quoting MEC/NRDC/SC exceptions at 10-11.
[2077] May 2, 2019 order, page 161.
[2078] May 2, 2019 order, page 161-162

messages among different customer groups and researching effective marketing and education." The Commission explained:

> Given the Commission's desire for DTE Electric to submit a more measured approach to this change to rate design (accompanied by reasonable cost projections) in its next rate case filing, and in light of recent issues with the company's billing system (see, Case Nos. U-18486 and U-20084), the Commission finds DTE Electric's recommended plan to be superior to the alternative plan and approves the recommended plan. The Commission believes that it is preferable to pilot multiple rates and to test multiple messages among different customer groups. The recommended plan allows the company an additional year to perform a thorough assessment and to develop a sound transitional plan for ratepayers, and the less-aggressive timeline should lead to more appropriate implementation costs. The Commission declines the request to reverse the 2018 orders; AMI has made this type of rate structure possible and DTE Electric needs to move forward with its provision. The Commission acknowledges the difficulty associated with the transition. In DTE Electric's next rate case filing, the Commission expects a comprehensive plan that offers a sound method for piloting the rate structure discussed herein and for making use of the data that is developed from the pilots, and that is supported by detailed information on the reasonable and prudent associated costs.[2079]

In that case, DTE's recommended plan was introduced as Exhibit S-16.1 by Staff witness Nicholas Revere, and provided the following schedule:

> In this case, planning for phase one would begin in December 2018, and would require 21 months to develop requirements, deploy the potential solutions, and allow for testing. Phase one of the Recommended Plan includes piloting up to 5,000 targeted customers per rate tested. Participants for the pilot will be targeted using the Company's customer segmentation research to ensure wide and varied participation. The pilot implementation would begin in June of 2020 and run through September 2020, after which it would be assessed and findings from the pilot will be implemented into the process for full implementation. Planning for phase two, full implementation, would begin in September 2020. This phase would require 21 months to gather requirements, develop and integrate with the billing system, and test the solutions. Residential customers who

[2079] May 2, 2019 order, pages 164-165.

> do not choose other rate options would be transferred to a new summer on-peak rate on May 30, 2022 on a bill cycle basis.[2080]

The ordering paragraph E. of the Commission's May 2, 2019 order directed DTE to file in its next rate case filing "a comprehensive plan for piloting new Rate D1 summer on-peak capacity and non-capacity rates, as described in this order."[2081]

DTE filed its next rate application on July 8, 2019 in Case No. U-20561. Shortly thereafter, on July 19, 2019, DTE filed an application in Case No. U-20602 seeking *ex parte* approval of its Advanced Customer Pricing Pilot, which included six separate rates, and authority to defer O&M costs up to $11.2 million from 2019 through 2021. The application was accompanied by the affidavits of Camilo Serna and Theresa Uzenski. Two of the pilots had both summer on-peak and -off-peak rates as well as non-summer on-peak and off-peak rates; the remaining four pilots incorporated demand-based rates. Included in Mr. Serna's affidavit was a cost estimate of $17.1 million including $5.9 million in capital costs, and the company's benchmarking results showing an average pilot cost per customer of $1,000 in comparison to the company's proposed cost of $977 per customer.

As explained in the Commission's September 26, 2019 order in that docket, MEC filed a petition to intervene and objections to the application; the Attorney General filed a notice of intervention and a request for a contested case hearing on the application. MEC objected on multiple grounds, including that the pilots did not resemble what the Commission had approved for a full program, summer on-peak rates on a default or opt-out basis, and that the company had not justified the projected $17.1 million cost for the

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[2080] Case No. U-20162, docket # 0436.
[2081] May 2, 2019 order, page 213.

pilots. The Attorney General also raised similar concerns in seeking a hearing. The Commission's September 26, 2019 order approved two of the rates, excluding four demand rates, as follows:

> The Commission finds that the first two proposed pilots, Rate Schedule D1-A (TOU I) and Rate Schedule D1-B (TOU II), should be approved, with one modification. See, Exhibit A-3, pp. 1-4. DTE Electric provides convincing evidence supporting the need for the opt-out option for Rate Schedule D1-B. Serna affidavit, p. 21. The Commission finds that the same reasoning applies to Rate A, and directs DTE Electric to revise the tariff for Rate Schedule D1-A to include the same opt-out language that is made available for Rate Schedule D1-B. See, Exhibit A-3, p. 3. The Commission views the approval of these two pilots as necessary to implement the Commission's decisions and guidance from prior rate case orders. The Commission believes there is value to be gained by the utility, the Commission, and ratepayers from these pilot programs, including learning about customers' reaction to the rate offerings and different outreach and communication methods. The Commission stresses the importance of customer education for the successful implementation of summer peak pricing rates.[2082]

The Commission addressed the deferred accounting request as follows:

> With respect to DTE Electric's request to defer O&M costs related to the implementation of the pilot rates, the Commission observes that the company's estimate of the costs is outdated in light of the decisions herein and directs DTE Electric to file an updated version of Exhibit A-2 in this docket within 30 days of the date of this order. The Commission will issue a further order thereafter.[2083]

The order gave DTE 30 days to file a revised cost estimate, Exhibit A-2 to the Serna affidavit. In its October 3, 2019 filing, DTE revised its request:

> In light of the Commission's order in this docket, the Company has revisited the costs associated with implementing the two approved pilot rates. The implementation of the two approved TOU rates is expected to result in incremental O&M costs of approximately $7.3 million through the end of the proposed Pilot period. DTE Electric requests Commission authorization to defer these one-time operating expenses incurred during

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[2082] September 26, 2019 order, page 3.
[2083] September 26, 2019 order, page 4.

> 2019 through 2021, not to exceed $7.3 million. A full description of the Pilot O&M costs may be found in Revised Exhibit A-2, attached to this update.[2084]

In its November 14, 2019 order, the Commission granted the request, noting that it was not making a determination whether the expenses were reasonable and prudent.

In its May 8, 2020 order in the rate case, the Commission acknowledged that DTE, Staff, and MEC Coalition in that case agreed that the pilot should move forward. The Commission then addressed Staff's recommendation that a time-of-use rate be set in that case:

> [T]he Staff seeks Commission approval of its summer-on peak rate, to be effective in May of 2022. The Commission finds that approval of the Staff's rate design would be premature in this case. As the parties acknowledge, there will be another contested case on this issue prior to the implementation of the Staff's proposal. Additionally, the pilot programs are designed to gather information and data to guide the implementation of these new rates. The Commission believes that this must be a deliberate, step-by-step process, which may require the implementation of additional pilots prior to the adoption of a rate design. The Commission finds the MEC Coalition's proposal for informal engagement with stakeholders outside of a rate case to be reasonable (and notes that the company indicated its willingness to accept stakeholder input), but declines to set a schedule for such an undertaking at this time, until these first two pilots have yielded some initial results. See, 4 Tr 531.[2085]

In a footnote, the Commission stated:

> While adopting the recommendations based on the record in this case, the Commission also notes that the impacts of the current COVID-19 situation may make implementation of the planned on-peak pricing pilot impracticable, and encourages the parties to continue discussion on plans to implement an on-peak pricing pilot for residential customers, based on the findings in this case and in Case No. U-20602.[2086]

[2084] October 3, 2019 application, paragraph 10.
[2085] May 8, 2020 order, pages 246-247.
[2086] May 8, 2020 order, page 240 at n16.

Disputes regarding the capital cost associated with the pilot projects were resolved between Staff and DTE. In its brief, Staff explained that it no longer objected to including the capital expense in rates based on the Commission's November 14, 2019 order in Case No. U-20206.:

> The Company requests $5,866,000 in capital spending associated with the pilot intended to test its new summer on-peak rate structures as directed by the Commission in the Company's previous rate case. (9 TR 3126.) The pilot is called the Advanced Customer Pricing Pilot. Because the pilot could not continue without Commission-approved rates, Staff recommended that the associated pilot capital spending be disallowed until an approval was formalized by the Commission. Id. The Commission approved the Company's ex parte case U-20602 that included tariffs for the pilot rates and deferral of pilot O&M expense after direct filing in the instant case. *In re DTE Electric Company's Advanced Customer Pricing Pilot*, MPSC Case No. U-20602, 11/14/2019 Order. For these reasons Staff no longer recommends disallowance of $5,866,000 in capital costs associated with the Advanced Customer Pricing Pilot. Due to filing deadlines, this recommendation is not reflected in Staff's case.[2087]

Staff's brief cited Mr. Isakson's testimony in that case, which had initially recommended excluding the $5.866 million cost, which in turn cited Daniel Griffin's testimony in that case:

> The Company proposes to recover $5.866M in capital for the Advanced Customer Pricing Pilot. However, the Commission has yet to approve the pilot, its tariffs, or even deferral of O&M costs. The Commission directed the Company to file an updated cost estimate for the pilot, so capital costs associated with the pilot should not be approved until the pilot itself is approved. It is currently unknown whether the Commission will approve the pilot, and therefore its related capital costs should not be approved until the matter is resolved in Case U-20602. This capital amount is a portion of the total $15.9M associated with the implementation of the SOP rate discussed by Company witness Daniel Griffin.

[2087] Case No. U-20561, Staff brief, docket #0439, page 15.

Mr. Griffin testified:

> The Company will invest $15.9 million in the Time of Use project to implement the proposed residential time of use Rate Schedules. Commission Order in Case No. U-20162 directs the Company to implement Time of Use and demand billing. The Company is proposing piloting multiple time of use and demand rates for a period of one year in order to evaluate the acceptance of this program on our residential customer base so that we can select the appropriate rate structures for full implementation. To accomplish this, the Company will create 6 new rates for the pilot: (2) Time of Use rates, (2) Demand rates, (2) Hybrid rates (TOU and Demand). During the pilot period, the Company will maintain bill accuracy within acceptable thresholds and adhere to controls established by past rate implementations. This Multi-Pilot approach will allow the Company to evaluate multiple residential rate structures, test and refine the messaging needed to keep our customers informed and perform a thorough assessment of the impact of these potential new rate structures. Investment in this project includes hardware, software, labor, Customer and Employee communications and all other aspects associated with a significant rate change initiative.[2088]

While not abundantly clear, it appears that in Case No. U-20561, Staff and DTE agreed that the pilot implementation capital costs would be $5.9 million, plus the additional $7.3 million O&M expense deferral approved in Case No. U-20602, with an additional cost of approximately $10 million for full implementation.

On June 17, 2020, DTE filed an application in Case No. U-20206, seeking to extend the timeline for implementing the summer on-peak rate for capacity and non-capacity charges, and the two pilots, citing the impact of Covid. It asked to be allowed to file its full implementation plan in 2022 and begin full implementation of the new TOU rates in 2023. MEC filed objections to the application. In its February 4, 2021 order, the Commission explained: “DTE Electric contends that if it is required to file a full implementation plan in 2021, the plan ‘would lack robust pilot learnings during the

[2088] Case No. U-20561, transcript volume 8 at Tr 2386.

critical summer months and fall short of the Commission's intent for pilots in the May 2, 2019 Order in Case No. U-20162.'"[2089] In granting the request, the Commission explained:

> The Commission reaffirms the critical importance of pilots, as described in the orders referenced by the company. However, pilots are only as useful as the data they gather, and the Commission agrees with DTE Electric that the work and home life changes brought on by the COVID-19 pandemic will not provide typical residential electric usage data. Thus, the Commission finds that the extension for the ACPP program should be approved, and that the timeline for full implementation should be extended to allow for the program to be available for summer 2023. 2 Because the extension of the timeline for the ACPP program will not result in an increase in the cost of service for any customer, the Commission finds that ex parte approval is appropriate. MCL 460.6a(3).
>
> Finally, the Commission clarifies 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. The Commission sees value in piloting the opt-in programs to test communication and customer engagement strategies that can inform the development of the full program, but continues to stress that the program developed for full implementation must apply to all residential customers – and not just those that opt-in – in a way that "send(s) the appropriate price signal for energy usage in each time period, and will more closely align energy rates with the costs caused by that usage." April 18 order, p. 82. The Commission again emphasizes the importance of pilot programs for providing informative and necessary data for the design of the final program, and for engaging and educating customers regarding the advantages of the new rate design. The benefits of the pilot process can be achieved only through the involvement of all stakeholders during the pilot period and in the process of development of the full proposal. "Frequent stakeholder engagement is critical throughout the entire pilot process." *Utility Pilot Best Practices and Future Pilot Areas*, September 30, 2020 Staff Report, Case No. U-20645, filing # U-20645-0003, p. 33 (note omitted); see also, pp. 33-34, 39-40.[2090]

[2089] February 4, 2021 order, pages 3-4.
[2090] February 4, 2021 order, pages 5-6.

This brings us to the present case. Mr. Foley and Mr. Willis explained DTE's proposal for full implementation of a residential time-of-use rate. Mr. Foley discussed what he acknowledged were preliminary results.[2091] He described the rates for each pilot:

> Rate Schedules D1-A and D1-B both vary by time of day and by season. Both have an on-peak period consisting of 3:00 pm to 7:00 pm, Monday-Friday (with an off-peak period consisting of all other times), and on-peak rates which are different for June-September versus October-May.
>
> D1-A was designed with a power supply non-capacity rate that varies by time and month as described above. 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. The power supply capacity rate is a "flat" per kWh energy charge, meaning the per kWh price remains constant throughout the year and does not vary based on the time of the day, the day of the month, or the month of the year.
>
> D1-B was designed with both power supply non-capacity and capacity rates that vary by time and month as described above. The differential between on peak and off peak are again based on historical locational marginal prices for the corresponding seasonal and intraday periods. However, instead of being based on the absolute difference between the different LMPs, the difference is based on the relative difference.[2092]

He explained the basic pilot enrollment:

> Each of the new TOU pilot rates were to be offered to 105,000 residential customers on an opt-in basis, with target enrollment on each rate of 2,500 customers who affirmatively chose to opt-in, after which additional customers would be allowed to participate at the Company's discretion.
>
> Each of the pilot rates was offered to an additional 5,000 residential customers on an opt-out basis as well, meaning these customers were notified that they were being placed onto one of the two rates before they became effective, and then had the opportunity to "opt-out" and remain on their legacy rate by notifying the Company either by calling the contact center or using the Company's self-service online functionality. Absent this

[2091] 6 Tr 1122.
[2092] 6 Tr 1136-1137.

> proactive notification from the customer, the customers were automatically transitioned to TOU rates in the Spring of 2021.[2093]

He stated that the pilot was ongoing at the time of the filing. Mr. Foley then discussed DTE's proposed full implementation, based on the first of the two pilots, Rate D1-A. He reserved for himself the discussion of the rate design and "transition strategy," explaining that Mr. Willis presented the proposed tariff, Mr. Burns discussed customer education, Mr. Sparks discussed the customer service costs, and Ms. Pizzuti discussed the IT costs.[2094] Mr. Foley testified that the company's rate design for this rate replaces the "inverted block" structure for recovery of capacity costs with a flat per/kWh charge, and recovers the non-capacity portion of power supply costs through a time-of-use structure. He further explained the time-of-use cost recovery:

> As discussed previously in my testimony, the most appropriate costs to recover through per kWh TOU pricing are fuel and energy-related purchased power, both of which are contained within 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 cost for the respective cost type, and therefore send the most accurate pricing signals to customers to encourage efficient, low-cost asset use. As such, the Company is proposing to apply TOU pricing to only the Non-Capacity portion of Power Supply costs.[2095]

He explained the flat per/kWh charge for capacity power supply costs:

> With the introduction of the TOU pricing structure applied to the Non-Capacity portion of Power Supply, customers will already be receiving a more nuanced pricing signal that encourages them to reduce their usage during the time of highest aggregate system demand. As such, if the "inverted block rate" were retained, it would send a superfluous, and potentially confusing, pricing signal to customers. Therefore, the Company

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[2093] 6 Tr 1136.
[2094] 6 Tr 1137-1138.
[2095] 6 Tr 1139.

> is proposing to not use this structure for Power Supply Capacity costs in its Rate Schedule D1.11.[2096]

Mr. Foley confirmed the followed two differences between DTE's proposal and Consumers Energy's current time of use rate for residential electric service:

> • The Company is proposing that TOU pricing only apply to the Non-Capacity portion of Power Supply. Consumers Energy's rate applies TOU pricing to both the Capacity and Non-Capacity portion of Power Supply.
>
> • The Company is proposing that TOU pricing be effective during the entire year. Consumers Energy's rate has TOU pricing effective only during the summer months.[2097]

Mr. Foley testified limiting the time variant rate to collection of non-capacity costs will help limit potential bill impacts and allow customers to "get comfortable with the new rate structure." He opined that a year-round time-of-use rate would promote customer understanding:

> Employing the TOU structure only during the summer months would require changing customer pricing signals two times during the year – once when entering the summer months signaling the start of TOU pricing, and once after the summer months when "flat" pricing would take effect. The Company believes this has the risk of not only confusing customers and potentially resulting in reduced customer satisfaction, but also of not resulting in a lasting shift in customer behavior.[2098]

But he also explained that DTE's proposal uses different differentials for the summer and non-summer months:

> Even in non-summer months there is a meaningful difference between on-peak and off-peak market energy prices. As such, the Company considers it appropriate to retain the TOU structure in non-summer months to reflect these differences. With that said, the on peak to off-peak market energy price differential is greater during the summer months, which is why the

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[2096] 6 Tr 1140.
[2097] 7 Tr 1141.
[2098] 6 Tr 1142.

> Company is proposing to have "summer" pricing and "non-summer" pricing as described by Company Witness Willis.[2099]

Mr. Foley described DTE's review of the pilot results from the summer months, using a control group it determined to be similar to the pilot participants in the opt-out group and finding a less-than-1% reduction in peak load for customers on either pilot.[2100] He testified that based on these results, the company considers it unreasonable to subject customers to the higher peak rates associated with the capacity and non-capacity pilot "when aggregate load impacts are likely to be similar and a higher pricing differential could subject individual customers to more severe bill impacts."[2101] He also testified that DTE should be allowed to update its billing determinants to adjust for potential load shifts, if a different rate structure is chosen.

Mr. Foley then testified that DTE is proposing to use an opt-out strategy for full implementation of this TOU rate, with customers given a 60 notice of the upcoming change: "The Company anticipates that customers will be able to provide notification of their desire to opt-out through an online tool or by calling the Company's contact center."[2102] He testified that customers would then be able out-out annually and return to Rate D1, and further explained:

> It is the Company's intent to maintain a high level of enrollment on the D1.11 rate and will take all reasonable actions with its customers to do so. In support of this objective, the D1.11 rate would become the default rate for new residential customers and customers changing premises, similar to how the D1 rate acts as the default rate today. New or moving customers would still be able to take service under the D1 rate but would have to proactively choose to do so. Absent this proactive choice, they

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[2099] 6 Tr 1142.
[2100] 6 Tr 1144.
[2101] 6 Tr 1145.
[2102] 6 Tr 1146.

> would be placed on the D1.11 rate. This should help support a high level of enrollment on the D1.11 rate.[2103]

He testified that DTE plans to complete transitions to this rate by May 31, 2023. He also identified one additional learning from the pilot, that the opt-out rate was only 5.6%.[2104] He discussed the benefits of retaining an opt-out provision and testified that DTE intends to retain Rate D1.

He presented a table summarizing the company's projected costs for full implementation at 7 Tr 1152. This table shows "one-time project O&M" costs of $17.1 million for customer service, customer outreach, and IT, in addition to IT capital costs of $30.17 million.

Mr. Willis testified regarding details of the rate design as shown on page 11 of Exhibit A-16, Schedule F3.[2105] He explained:

> The billing determinants are based on those used for the D1 rate design, which were developed based on historical data and relationships, as well as known and measurable, and assumed changes, and are consistent with Witness Leuker's sales forecast. I assumed a 3% shift from on-peak to off-peak usage, and no overall reduction in usage.[2106]

Mr. Willis noted that the peak times match the pilots, and further testified that the rate was designed to be revenue neutral relative to Rate D1:

> The power supply non-capacity rate differential between on peak and off peak is derived from the seasonal and intraday variations of historical (2018-2020) locational marginal price (LMP). The proposed power supply capacity rate is a static energy charge. The distribution/delivery rates proposed match those proposed for Rate Schedule D1. As can be seen by comparing the bottom of columns (d) and (f), the proposed Rate Schedule

[2103] 6 Tr 1147.
[2104] 6 Tr 1148.
[2105] 6 Tr 927.
[2106] 6 Tr 928.

> D1.11 is designed to be revenue neutral to the proposed Rate Schedule D1.[2107]

Mr. Willis further discussed alternatives for determining the appropriate differential.[2108] He presented tariff sheets for this rate, and also proposed new naming conventions for the company's residential tariffs.[2109]

Several witnesses addressed DTE's proposal. Mr. Richter objected that the cost differentials did not reflect differences in the cost of capacity or delivery.[2110] He noted that DTE had piloted a rate with a greater differential, although characterizing it as "still quite small," he testified that impact was more than twice the first pilot. Citing examples of other utilities with greater on-peak pricing differentials, he recommended that the Commission require DTE to redesign its rates to "recover all, or most, of capacity costs from on-peak usage."[2111] Mr. Lucas considered the differential modest, and addressed DTE's projected 3% shift in load in contrast to the pilot results:

> The Company assumes that customers will shift an additional 3% of their usage from on-peak periods to off-peak periods, and do so not just in the summer, but year-round. In other words, while the D1-A rate produced a 0.4% reduction in summer on-peak usage, the Company assumes the D1.11 Standard TOU and D1.12 Stable Bill will drive reductions roughly eight times larger, including during non-summer months when the rate differential is practically zero.[2112]

Mr. Lucas objected that DTE had no support for this 3% assumption:

> When asked to provide support for this figure, the Company only responded that its D1-A and D1-B pilots were "currently ongoing and incomplete." It also referenced a 14% shift assumed by Consumer Energy ("Consumers") in Case U-20134, comparing it to its "initial forecast

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[2107] 6 Tr 928.
[2108] 6 Tr 928-930.
[2109] 6 Tr 932-934.
[2110] 8 Tr 3233-3237.
[2111] 8 Tr 3240.
[2112] 8 Tr 3584.

> assumption" of 3%. In a follow up query, the Company again acknowledged that it has no quantitative analysis to support this position, only its "qualitative analysis."[2113]

He considered DTE's reliance on Consumers Energy's assumption, and found it inapplicable, citing in particular the Consumers Energy pilots' longer peak periods, higher peak differential and "more importantly," its critical peak pricing signal.[2114] He testified that if consumers do not shift usage as DTE projects, it will collect excess revenue. Citing Exhibit CEO-18, he testified:

> All else equal, if customers shift their energy usage less than DTE projects, the Company will over-collect revenue. Company Witness Willis calculated this impact and found that if there is no shift, DTE would over-collect roughly $571,000, and if there was a 0.5% reduction – in line with the D1-A pilot rate summer reduction – there would be an over-collection of roughly $474,000.[2115]

For purposes of DTE's rate design, he recommended that the Commission use the 0.4% shift identified in the summer portion of the pilot, but his overall recommendation is that the Commission should require DTE to redesign the rate:

> I recommend the Commission direct the Company to redesign its D1.11 rate to substantially increase the TOU differential to better reflect the underlying cost of providing energy during peak hours. At a minimum, DTE should have a rate differential at least as large as the D1-B rate in all months, with a higher differential during summer months. Customers who are unable or unwilling to adjust behavior will still have the option to opt out of the rate.[2116]

After discussing principles of rate design, Mr. Jester characterized DTE's proposal as fa small step in the right direction:

> The proposed rate schedule D1.11 is a small step in the right direction. It applies time of use rates to the non-capacity-related production costs

[2113] 8 Tr 3584.
[2114] 8 Tr 3585.
[2115] 8 Tr 3586.
[2116] 8 Tr 3587.

> allocated to residential customers. The proposed pricing intervals are likely not ideal, especially in the long-run, but are not unreasonable so I do not object to them at this time. The use of LMP differences to establish price differentials is also reasonable at this time.[2117]

He considered that capacity costs and distribution costs should also be collected through time-variant rates, and recommended that the Commission require DTE in its next rate case to redesign the rate to collect these costs, also, through a time-of-use rate design.[2118]

After discussing general principles of cost-alignment and rate design, Mr. Revere explained Staff's view of certain aspects of DTE's proposed rate design. First, he discussed the recovery of capacity costs, disputing Mr. Foley's testimony that such costs should be collected through a demand rate:

> [A] demand-based rate is not the most appropriate way to collect demand-related power supply costs from large classes of diverse customers, such as the residential class, as it does not best align with the underlying drivers of the cost. In fact, it is more appropriate to collect those costs through a time-varying rate i the periods those peaks are most likely to occur, such as the peak window for the new time-varying rate. Including all such costs in such a small window of time, however, would result in rates that, in Staff's opinion, would currently be unreasonable. It is also important to note that the method currently used to determine the Company's capacity costs has a result significantly higher than the cost of new entry (CONE), or the price t build a gas combustion turbine (CT), whose purpose is effectively to supply capacity. While Staff is not making an argument in the instant case that the current calculation should be changed, it would be unreasonable to include all cost identified as capacity i the capacity charge during on-peak hours. Therefore, rather than a flat capacity rate over all kWh, it is more appropriate (and cost-aligned) to begin by collecting those costs through rates that are 50% higher in the summer on-peak period. This is similar to the current method for Consumers Energy's Summer On-Peak rate.[2119]

[2117] 8 Tr 3852.
[2118] 8 Tr 3852-3853, 3855.
[2119] 8 Tr 5134.

Mr. Revere also disputed M. Foley's contention that if the differentials are altered, the billing determinants should be altered as well:

> First, Company witness Foley states there is not a substantial difference between customer on-peak usage under the two differential options from the Company's perspective. Company witness Foley Direct, p. 25. This alone should make the change unnecessary. Second, the Company has already assumed a 3% peak shift from implementation of the lower differential, well above even what was experienced from the larger differential during the pilot. Therefore, no adjustment to the determinants would be necessary if the larger differential were approved.[2120]

Mr. Revere recommended the use of the percentage difference in LMP prices rather than the absolute difference in setting the peak rate differential, characterizing it as more representative of the difference in price.[2121]

Mr. Revere presented DTE's "Alternative Recommendation," which he obtained through an audit request, as Exhibit S-23.01. He testified that this alternative proposal "corrects a number of the deficiencies in the Company's initial proposal," such as the inclusion of capacity costs as well non-capacity power supply costs. He testified that "[t]he Alternative Proposal is also substantially less expensive to implement."[2122] Mr. Revere recommended approval of the Alternative Recommendation "with the modifications described by Staff above in relation to the Company's initial proposal."[2123] Mr. Revere also addressed DTE's cost projection:

> The costs listed on Exhibit S-23.01 would need to be added to the calculation of the revenue deficiency (minus the contingency amount for the reasons supported by Staff witness Rogers) in the Commission final order. The costs of the initial proposal were removed from Staff's case due to the class of the estimate by Staff witness Rogers. In my understanding,

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[2120] 8 Tr 5135-5136.
[2121] 8 Tr 5136,
[2122] 8 Tr 5137.
[2123] 8 Tr 5137.

> the class of the estimates I am proposing being included is such that no similar disallowance is being proposed.[2124]

In his revised rebuttal testimony, Mr. Foley acknowledged the testimony of witnesses as discussed above, and presented DTE's discovery response to Staff as Schedule JJ1 (revised) of Exhibit A-45, testifying:

> In response to Audit DWI-1.1 (Exhibit A-45 Schedule JJ1), 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 No Capacity portions of Power Supply. As part of that response, the Company indicated that "it is supportive of a Commission order directing the Company to implement either its Original TOU Full Implementation proposal or its Alternative TOU Full Implementation proposal."
>
> As such, the Company does not oppose intervenor recommendations to extend TOU pricing to Power Supply Capacity rates as proposed by the Company in its Alternative TOU Full Implementation proposal if the Commission deems it appropriate to do so.[2125]

In his rebuttal, Mr. Willis addressed Mr. Revere's concern with DTE's use of absolute differences between LMP rates rather than percentage differences by referencing DTE's alternative proposal:

> The Company's alternative proposal described in response to Audit DWI18 1.1 and reflected in Staff Exhibit S-23.00 supports varying both power supply capacity and non-capacity rates by the percentage difference in LMPs, as described by Witness Revere on Pg 14, Ln 19. This results in a ~64% summer and a ~15% winter power supply differential.

He disagreed with Mr. Revere's preference for a summer-only on-peak rate for capacity costs as shown in Exhibit S-6, Schedule F4, pages 20-21:

> Witness Revere proposed to vary the non-capacity by percentage difference in LMPs and summer capacity by 50%, with no variation in non-summer capacity costs. In addition, the Company does not agree that

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[2124] 8 Tr 5137.
[2125] 6 Tr 1191-1192.

> capacity costs should only vary in the summer months. The rate structure should be consistent year-round, reflecting the variation in the cost of capacity requirements outside of the summer months.[2126]

Mr. Willis acknowledged Mr. Lucas's concern with the 3% shift in the company's initial proposal but disputed that would be a concern with the company's alternative proposal.[2127] He added:

> Following implementation of the new D1.11 rate, the Company will have D1.11 usage data for the ~1.9 million customers expected to take service on the rate and will propose billing determinants based on known, historical information on that rate. This is consistent with Commission precedent for addressing load shift assumptions for a broad, mandatory TOU implementation when full historical data was unavailable.[2128]

He did not further address the 3% assumption in the context of DTE's initial proposal.

In their briefs, DTE,[2129] Staff,[2130] and MNSC[2131] generally support the alternative proposal, and Staff has included the revised cost estimate in its revenue requirement projection. Staff's brief explains its objections to the company's initial proposal as having too limited of a differential and relying on absolute rather than relative differences in LMP prices. MNSC argues that the Commission "should instruct DTE to propose a time-based rate for distribution costs in its next rate case."[2132] DTE discusses its initial proposal more extensively in its initial brief relative to the alternative proposal.[2133]It also addresses Mr. Lucas's testimony by citing Mr. Willis's rebuttal and explaining that the company's alternative proposal would vary both capacity and non-capacity rates.[2134]

[2126] 6 Tr 971-972.
[2127] 6 Tr 977-978.
[2128] 6 Tr 978.
[2129] DTE brief, 241-246.
[2130] Staff brief, 247.
[2131] MNSC brief, 102-103.
[2132] MNSC brief, 103.
[2133] DTE brief, 241-246.
[2134] DTE brief, 244.

The Attorney General argues that DTE's initial proposal goes beyond the summer on-peak rate directed by the Commission, and objects to DTE's alternative proposal on the basis that it "has not been sufficiently vetted and comes too late in the proceeding."[2135] The CEO also argue that the alternative proposal could not be adequately evaluated:

> The Company has supplemented their original proposal with an "Alternative Proposal," presented by Witnesses Foley and Willis in rebuttal testimony. See Audit Response DWI-1.1; Willis Rebuttal, 6 TR 926. This new alternative proposal "mimics" an existing DTE pilot program, the D1-B rate. Id. However, the Company has yet to release the full details of this proposal, 6 TR 1006-7, which leaves intervenors grasping at straws in order to assess its merits. In rebuttal testimony, Company Witness Willis acknowledged CEO Witness Lucas's argument, but failed to provide any reasons why Witness Lucas's observations were inaccurate, and summarily urged the Commission to approve the Company's unsupported 3% load shift. Willis Rebuttal, 6 TR 925.[2136]

The CEO cite cross-examination of Mr. Willis in which he acknowledged that he had not calculated the on-peak and off-peak rates associated with the new proposal, but would do so "if that's the order in rate design."[2137] The CEO also continue to maintain that DTE did not support the 3% shift, characterizing it as "overly optimistic at best, and more likely unachievable."[2138]

In its reply brief, DTE addresses the Attorney General's cost concerns by reiterating its view that the Attorney General mistakenly believes the costs are all for the pilots. DTE also argues that the company's alternative plan presented costs that are 35% lower, "which Staff supports," and cites the revised cost figures in Exhibit S-

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[2135] Attorney General brief, 69.
[2136] CEO brief 19.
[2137] 6 Tr 1006-1007.
[2138] CEO brief, 20.

23.01.[2139] In response to the CEO brief, it also notes the response in its initial brief to Mr. Lucas's concerns. In its reply, Staff disputes that the intervenors did not have adequate time to review what it labels as Staff's proposal:

> The Alternative Proposal was proposed by Staff on direct testimony, including the costs, providing time for it to be examined by the other parties. A similar rate was piloted along with the rate the Company's initial proposal was based on and requires no more justification than that which is on the record in the instant case. (Staff Initial Brief, p 247.) For these reasons, as well as those discussed in Staff's Initial Brief, the Alternative Proposal should be approved as modified above.[2140]

After reviewing the available evidence and the Commission's prior orders, this PFD concludes that DTE has not presented an approvable time-of-use rate. The company's initial time-of-use rate, while generally described as "modest" by the reviewing parties, was accompanied by an unexplained and unjustified cost estimate, as well as a projected load shift that it could not explain when questioned. (Staff's view seems to be that load shifts need not be considered because the purpose of the change is not to shift load but to reflect costs.) DTE acknowledged that its review of the pilot programs was "preliminary," and it made no effort to analyze any pilot experiences beyond the summertime, notwithstanding that its proposal maintains a differential between on-peak and off-peak rates throughout the year.

As to DTE's alternative proposal, first presented by Staff as an exhibit, without discussion of a key difference between the pilot programs and the alternative proposal, the absence of an opt-out provision, this PFD also concludes that proposal is not approvable. DTE did not attempt to justify the change from an opt-out tariff to a

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[2139] DTE reply, 110.
[2140] Staff reply, 31-32.

mandatory tariff, notwithstanding Mr. Foley's extensive testimony in direct in support of an opt-out provision and notwithstanding the Commission's requirement in Case No. U-20602 that the pilot programs contain an opt-out provision. While Mr. Foley purported to respond to the testimony of witnesses objecting to the modest rate differential in the company's initial proposal, he quoted a portion of Mr. Lucas's testimony that explained customers' ability to opt out,[2141] without expressly acknowledging that was not part of the company's proposal. The word "opt-out" does not otherwise appear in Mr. Foley's rebuttal or Mr. Revere's direct testimony. DTE also did not present a revised tariff for this alternative proposal,[2142] a revised tariff to limit the current Rate D1.1 only to "AMI opt-out" customers, or a comparison of bills at present rates. While the Attorney General and the CEO object to the late presentation of this alternative—DTE could have asked to present this alternative as a modification of its direct case—this PFD finds most persuasive the Commission's order in Case No. U-20602, quoted above, stating unambiguously:

> The Commission again emphasizes the importance of pilot programs for providing informative and necessary data for the design of the final program, and for engaging and educating customers regarding the advantages of the new rate design. The benefits of the pilot process can be achieved only through the involvement of all stakeholders during the pilot period and in the process of development of the full proposal. "Frequent stakeholder engagement is critical throughout the entire pilot process." *Utility Pilot Best Practices and Future Pilot Areas*, September

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[2141] 6 Tr 1191.

[2142] In its reply brief, DTE appears to acknowledge this at page 178, asserting: "In the event the Commission approves the 'Alternative TOU Full Implementation', the corresponding contract term language in Exhibit A-16, Schedule F8, sheet D-14.06 should reflect the default nature of the rate schedule and therefore the "Contract Term" provision in Exhibit A-16, Schedule F8, sheet D-14.06 should be stricken and replaced with the contract term language set forth on Exhibit A-16, Schedule F8, sheet D-2.00." The referenced sheet D-2.00 states under the heading "contract term" the following: "Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider."

> 30, 2020 Staff Report, Case No. U-20645, filing # U-20645-0003, p. 33 (note omitted); see also, pp. 33-34, 39-40.[2143]

Clearly, given the way the alternative proposal was presented and the objections raised by the Attorney General and the CEO, there was no effort made to involve all stakeholders in its development.

As discussed above regarding the cost of the projects as originally filed, Mr. Coppola expressed incredulity. Ms. Rogers noted that DTE included contingency and did not disclose it, and then revised its statement of the contingency included.[2144] She explained the difficulty this causes:

> Although asked through discovery to identify contingency, emergent, or reserve costs included in any cost categories in Company Exhibit A-12, Schedule B5, which includes Information Technology on Line 10, the Company did not identify contingency in the ACPP/Time of Use IT project until specifically asked if contingency was included in any IT projects. By not identifying the contingency costs in the ACPP/Time of Use IT project in the Company's initial filing, the Company has violated the provisions set out in the Commission's Rate Case Filing Requirements. Failure to disclose this information causes distrust and makes Staff question if the Company is hiding, masking, or burying similar costs in other projects.[2145]

DTE also made no effort to justify its initial or revised cost estimate. As discussed in the IT section of the rate base discussion, DTE's cost estimates for IT projects are wildly inaccurate, and contain substantial and unexplained overlap with other projects, frustrating evaluation of any particular project. DTE's presentation of revised costs through a discovery response to Staff lacks any reconciliation to its early projections and thus any explanation for the change. For IT, DTE did not present revised "business case" documents. For its O&M expenses, it is clear from a comparison of the figures on

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[2143] February 4, 2021 order, pages 5-6.
[2144] 8 Tr 5338.
[2145] 8 Tr 5340.

Exhibit S-23.01 that DTE projects it would spend $5.1 million on customer outreach for the alternative proposal compared to $8.1 million for its initial proposal, but has no explanation for the change. In theory, with the larger price differential under the alternative proposal, and no opt-out available, a reasonable person might conclude DTE's outreach efforts would be greater. (As a reminder, Mr. Foley testified: "The Company appreciates that all customers may not want to take service under a TOU structure, as evidenced by the opt-out rate experienced during the ACPP. As such, the Company considers it appropriate to provide these customers with an option to remain on their current rate if they so desire. This optionality should help mitigate risk of customer dissatisfaction.") Neither Mr. Burns nor Mr. Sparks presented rebuttal testimony addressing these revised cost estimates. With no justification for the revised projections, the company's revised costs could merely reflect a second look at its initial cost projections in light of Mr. Coppola's testimony and in anticipation of additional scrutiny from the Commission, as exemplified in the Commission's September 26, 2019 order in Case No. U-20602.

This PFD recommends that the Commission delay implementation of the full time-of-use rates once again, direct DTE to file a one-year review of the pilot programs and to confer with stakeholders on the design of a full time-of-use rate. This PFD further recommends that the Commission require DTE to provide the basis for each of the cost estimates it provided the Commission regarding work related to time of use rates, including the cost estimates in Mr. Serna's affidavits in Case No. U-20602, in its IT business cases presented in this case and in Case No. U-20561, and in Mr. Foley's, Mr. Sparks' and Mr. Burns' testimony in this case. Future cost estimates accompanying a full time-of-use rate proposal should be accompanied by detailed cost estimates with vendor bid results and a detailed transition plan including educational and marketing materials.

Should the Commission nonetheless wish to approve a full time-of-use rate in this case, this PFD recommends that the Commission approve the company's initial proposal, with the pilot result of an 0.4% load shift, grant deferred accounting for its capital and O&M costs, subject to a review for reasonableness and prudence, and require the same reporting and same scrutiny regarding the company's cost estimates as discussed above.

2. Billing determinants (other)

The CEO raise an issue with DTE's use of sales forecast data to derive billing determinants. Mr. Lucas explained the sales projections underlying the billing determinants:

> DTE took data from 2020 and forecasted billing determinants for its future test year of November 2022 through October 2023. This process required the Company to account for the surge in residential usage in 2020 caused by the COVID pandemic. In the Company's forecast, the excess COVID usage is expected to recede by the end of 2022. It also adjusted its forecast to account for weather-normalized sales, an increase in energy waste reduction ("EWR"), and customer shifts between tariffs.[2146]

Mr. Lucas then explained the translation from sales forecast to billing determinants for the residential rate schedules:

> While most of these adjustments were applied proportionately to all the residential tariffs, some were not. For example, DG and EWR reductions were applied reasonably to each tariff based on the relative share of residential sales. Weather normalization was likewise applied consistently, as was load growth from new customers. However, the largest

[2146] 8 Tr 3593.

> adjustment – the Customer Usage category which contained the COVID adjustment – was not applied equally. Instead, DTE used the D1 tariff as a "plug" to reconcile the total anticipated adjustments with the non-D1 tariff changes.[2147]

He testified that the 883,654 MWh reduction in the D1 sales dwarfs the projected increase due to new load of 129,943 MWh, resulting in a net reduction of 594,343 MWh, while the other residential rate schedules show net increases.[2148] He put this in context:

> This exogenous adjustment alone is equal to 6.0% of the historic year D1 sales and is by far the largest adjustment directly or indirectly applied to the residential forecast. Based on DTE's anticipated D1 monthly usage of 576 kWh, this adjustment is the equivalent to the consumption of about 128,000 customers.[2149]

He testified that a 1% underprojection of the D1 billing determinants is equivalent to a $24 million overprojection of rates.[2150]

In rebuttal, Mr. Willis testified:

> The method to allocate residential sales is consistent with the method utilized by the Company, and ordered by the Commission, in the most recently approved case (MPSC Case No. U-20561) and those prior. This consistency includes both the categories of changes within the forecast and the billing determinant workpaper and the methods used to allocate the changes. Witness Lucas acknowledged the Company's explanation of why residential sales are allocated to rate schedules in the manner they are and did not dispute the reasonableness of the approach. Witness Lucas further stated "In a normal case…this approach may be fine" while indicating that "massive changes in the historic 2020 data" are abnormal. However, Witness Lucas does not describe why the proration approach he recommends is more appropriate than the method utilized by the Company, offering only that the Company's method "overstates" the customer usage adjustment to D1.[2151]

[2147] 8 Tr 3594
[2148] 8 Tr 3595.
[2149] 8 Tr 3595.
[2150] 8 Tr 3595-3596.
[2151] 6 Tr 979.

In addition to relying on an approved methodology, Mr. Willis cited Mr. Lucas's testimony that ordinarily DTE's method would be reasonable, and also testified that the difference is minor given that the D1.1 rate includes 90% of all customers. [2152]

The CEO argue that the Commission should reject the company's allocation of projected sales reduction in the residential class as a whole to Rate D1.[2153] They argue:

> In doing so, the Company ignores important trends in work-from-home, return to the office and the general trajectory of the COVID-19 pandemic. Lucas Direct, 8 TR 3597. The risk in using the residential D1.11 rates as the "make-weight" for the rest of the sales forecast, is that the Company may overearn on residential rates in the test year. For every 1% energy usage reduction that is not attained, the Company will over-earn an additional $24.4 million form the D1 Tariff alone." Lucas Direct, 8 TR 3596 citing U-20836 Rate Design Model for Filing.xslx.[2154]

They emphasize that Mr. Willis did not address the impact of the pandemic on the company's predictive abilities, given the underlying changes in usage patterns. The CEO argues that the Commission should require DTE to spread the reduction in usage it attributes to the post-COVID environment to all residential rate schedules. Further, they argue that the Commission should require DTE to update its forecasting to reflect modern trends in working from home.

DTE relies on Mr. Willis's rebuttal testimony in objecting the CEO recommendations, and also objects to any contention that Mr. Leuker's forecast is inadequate.[2155]

This PFD concludes that the CEO recommendation should be adopted in so far as it seeks to spread the additional sales reductions across the other residential rate

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[2152] 6 Tr 979-980.
[2153] CEO brief, 23-28.
[2154] CEO brief, 24.
[2155] DTE brief, 230-231; DTE reply, 166-168.

schedules. Mr. Willis is clearly capable of making the modifications, since he was able to identify the magnitude, and did not dispute that DTE spread other adjustments to the different rate schedules. While Mr. Willis may be correct that it makes little difference to the ultimate rates given the size of the D1 customer group, it would appear to be more proper.

3. RIA and LIA tariffs

Staff and DTE have competing revisions to the tariff provisions addressing RIA and LIA credits. Mr. Willis presented DTE's proposal in Exhibit A-16, Schedule F8. Ms. Braunschweig presented Staff's recommendation in her testimony. Among Staff's chief concerns is that the assignment of eligible customers to the limited LIA enrollment opportunities should be done randomly, while DTE argues it should be at the company's discretion.

In his direct testimony, Mr. Willis deferred to Ms. Johnson for an explanation of the tariff changes.[2156] Ms. Johnson identified three changes "to standardize and clarify the two sections":

> 1. RIA and LIA already contain qualification provisions including the customer providing annual evidence of receiving Home Heating Credit (HHC) or Medicaid. The Company proposes to modify customer qualification requirements such that customers must verify receipt of one of the following in the last 12 months: HHC, State Emergency Relief, Michigan Energy Assistance Program, Medicaid, or Supplementary Nutrition Assistance Program. The Company also proposes that if the customer cannot verify that they meet any of these requirements, a self-attestation form must be completed and provided to the Company. For LIA, the Company is also proposing that in addition to the income verification methods listed above, a customer may qualify with proof of enrollment in the Company's affordable payment plan as sanctioned under

[2156] 6 Tr 933.

the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the last 12 months.

2. Clarifying that the LIA credits will be distributed at the Company's discretion.

3. Clarifying that if participation results in a credit balance that it may only be applied to future billed amounts, and that in no case will a refund be issued.[2157]

Ms. Braunschweig explained Staff's concerns initially in regard to DTE's reservation of 5,000 LIA spaces for senior citizen customers:

> The Company has not provided a compelling reason and/or supporting evidence for why senior citizen customers should be prioritized over other low-income households. It would be inappropriate to limit certain customers' access to assistance opportunities without supporting why one group should be prioritized over others. In the future, Staff recommends the Commission require the Company provide more substantial supporting evidence for such low-income proposals, including evidence for how a program change can improve upon equity, when appropriate.[2158]

She further explained that in the absence of a compelling priority, a random selection of participants would be equitable:

> Unless the Company proposes a reasonable equity framework for enrollment in future, Staff recommends enrollment in the LIA be randomized. The Company should be required to consult with Staff on any equity proposals for LIA, and after such consultation the Company should be required to file a formal request in a rate case or ex-parte case in order to make changes to how enrollment is performed for the LIA—if customer enrollment is no longer chosen at random from RIA enrollments. As described in Exhibit No. S-9.0 and S-9.1, the Company engaged in this practice prior to informing Staff in the current rate case and did not previously seek approval from the Commission. In Staff's opinion, this use of the language in the tariff allowing for the Company's discretion in the distribution of the LIA was inappropriate, and the language should therefore be changed.[2159]

[2157] 5 Tr 817-818.
[2158] 8 Tr 5272.
[2159] 8 Tr 5272-5273.

The text of the tariff Staff offered included the following:

> LIA customer selection will be random and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months . . . [2160]

In rebuttal, Ms. Johnson contends that Staff is recommending an “overhaul” of the RIA and LIA programs,[2161] seemingly conflating Staff’s recommendation regarding the rate case projections with Staff’s recommendations regarding enrollment: “The Company recommends that the Commission reject Witness Braunschweig’s proposal for limiting RIA enrollments forecast to 33,000 with any overflow moving to LIA enrollments of 32,000.”[2162] She further asserted that Staff’s proposed tariff language conflicts with the company’s pairing of the LIA credits with its LSP;

> Adopting a random application of the LIA credit would reverse the current successful policy of pairing LIA with the Low Income Self Sufficiency Plan (LSP). Randomly applying the LIA credit is less effective than the intentional application of the LIA credit with those customers enrolling in the Company’s Affordable Payment Plan (APP), LSP. LSP allows customers to work towards self-sufficiency and prevention of disconnection while providing comprehensive support to help eligible customers afford their utility. There is a broader burden on ratepayers when customers who need more support than just the LIA credit fall into disconnect and final account status which can result in uncollectible expenses passed to customers in rates. The Company recognizes the greatest success for uninterrupted service is when the LIA credit is used with LSP enrollment. A random application of the credit could be far less impactful on a customer’s bill affordability.[2163]

DTE relies on this testimony in its brief asking the Commission to approve the company’s proposed tariff.

[2160] 8 Tr 5279.
[2161] 5 Tr 833.
[2162] 5 Tr 834.
[2163] 5 Tr 832.

In its brief, Staff argues that DTE did not support the "success" of this pairing, and Staff continues to recommend a random selection for the LIA credit.[2164] It's reply brief further states that the customers participating in the LIA should be randomly chosen monthly.[2165]

Among the issues the DAAO raise with the credit, the DAAO raise a concern that DTE is not providing the available LIA credits:

> [T]he Company artificially and unnecessarily limits the participants in the higher-credit LIA program to far too low a number. DTE should grant LIA grants to all eligible residents, rather than pick and choose which of the eligible customers are most deserving. In the alternative, DTE should substantially raise the enrollment cap—at least to 50,000 participants. DTE often grants LIA credits to LSP participants, but there is no reason to limit the LIA cap to LSP participants when "so many more people could benefit from [the program] at this time." DTE has even previously argued that the cap should be raised to 50,000, explaining that there would be "no shortage of Non-LSP low[-]income customers enrolled in LIA and receiving the credit." Though the Commission maintained the LIA enrollment cap at 32,000 in the last rate case, it clearly stated that the LIA program should be revisited in the next rate case.[2166]

The DAAO view Staff's concern with the level of the rate case enrollment projections as based on a lack of evidence regarding the level of demand for the LIA credit.[2167] They thus argue:

> While it is appropriate to scrutinize any request from DTE for ratepayer funds, the solution is not to stymie enrollment during an affordability crisis without a clear alternative to meet potential demand. Instead, the Commission should both ensure that all eligible customers can be enrolled and demand that DTE deliver accurate data that assures against overcharging.[2168]

[2164] Staff brief, 224.
[2165] Staff reply, 17.
[2166] DAAO brief, 48.
[2167] DAAO brief, 48-49.
[2168] DAAO brief, 49.

After considering the arguments of the parties, this PFD finds it is premature to revise the tariff language. Staff's concern that DTE not assume full "discretion" to select recipients of the LIA credit is reasonable. The company's reticence to break apart the LIA and RIA enrollment data, its objection to Staff's assumption that the company will permit LIA enrollment up to the level of the cap, and the DAAO's contention that DTE is not fully utilizing the available LIA credits, cause a reasonable concern regarding the company's administration of these programs. If DTE is not at its LIA enrollment target, it has not explained why.

This PFD recommends that the company file a report detailing its current approach to enrolling customers in the LIA credit program, as well as current (2021 and 2022 to date) enrollment data. Once DTE's report is filed, this PFD recommends that the parties engage in discussions through the Energy Affordability and Accessibility Collaborative (EAAC). Among the topics to consider is Staff's recommendation that LIA credits be randomly assigned monthly. In conjunction with that discussion, to provide some continuity for customers, it would be appropriate for the parties to discuss raising the enrollment cap. While a random selection may be best, it is unclear on this record whether that selection must be made monthly as Staff argues, or if there could be an agreed upon time period for enrollment, which would provide opportunity for DTE to coordinate with its LSP program. The other "clarifying" changes DTE and Staff propose appear to be unnecessary to address at this time.

DAAO also argues that the LIA credit should be revised: "The Detroit Area Advocacy Organizations have a least three concerns with the LIA credit: (1) the LIA credits should be tailored to customers' income and usage rather than a flat rate; (2) the dollar amount of the LIA credit is too low; and (3) the number of potential enrollments in the LIA credit program is capped too low." Viewing the LIA credit as just a random additional offset to utility charges would seem to support DAAO's contention that the enrollment limit should be revised, but that is an issue that can be discussed in conjunction with a discussion of the utility's approach to administering this credit, which is not transparent on this record for the reasons stated above.

Staff argues that it is premature to revise the credit while DTE's "percentage-of-income payment plan" pilot program or PSP is still ongoing. Staff also disputes DAAO's contention that Staff's concern is that there is insufficient demand to justify an expansion of the LIA credit cap; it argues that Staff's ratemaking adjustment is intended to deal with rate case projections, not to address demand. Staff recommends that energy and affordability concerns, including consideration of lifting the LIA enrollment cap and the PSP, continue to be evaluated in the Commission's Energy Affordability and Accessibility Collaborative (EAAC).[2169]

Consistent with the general recommendations in this PFD that pilot results should be evaluated before further decisions are made, this PFD finds Staff's analysis persuasive and recommends that potential changes to the LIA credit, including adoption of a PSP-type program, be evaluated through the EAAC.

4. Stable bill

DTE proposes to add an optional[2170] residential demand rate, Rate D1.12, as discussed by Mr. Foley and Mr. Willis. Mr. Foley testified that DTE does not currently

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[2169] Staff reply 23-25.
[2170] This rate would not be optional for new DG customers. See, 6 Tr 935-936.

offer any residential demand rates, although the company did propose two demand-based pilot programs in Case No. U-20602. Mr. Foley noted that the Commission deferred these pilots, finding that more discussion was needed before approval.[2171]

Mr. Foley explained that residential customers seeking to reduce their bills now have two options: under the basic residential rate, Rate D1, customers can reduce their aggregate usage; and under TOU rates, customers can shift their usage from on-peak to lower priced off-peak periods. According to Mr. Foley, a demand rate offers customers a third option for reducing their electric bills by allowing customers to "*stagger* their usage in order to reduce their peak demand and lower their bill[,]" by avoiding the use of high-demand electric appliances (e.g., clothes dryers, ovens, air conditioning) at the same time.[2172]

Mr. Foley testified that proposed Rate D1.12 has three components: (1) a per kWh TOU energy charge to recover energy costs; (2) a fixed monthly delivery service charge; and (3) a monthly customer service level charge based on the demand the customer places on the system. Mr. Foley explained that the energy charge is designed to "mimic the Company's proposed D1.11 (Residential Service Rate – Standard TOU) rate to ensure consistency across rates[,]"[2173] and the fixed delivery charge is the same as applied to other residential rates.[2174] As for the service level charge, he testified that it "is designed to equitably recover all other costs not being collected through the per kWh TOU energy charge or the Delivery Service charge."[2175] The service level applied

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[2171] 6 Tr 1152, quoting the September 26, 2019 order in Case No. U-20602, pages 3-4.
[2172] 6 Tr 1153.
[2173] 6 Tr 1155.
[2174] 6 Tr. 1155.
[2175] 6 Tr 1155-1156.

to the customer, as shown in Exhibit A-16 Schedule F8, Sheets D-14.08–14.09, is based on a rolling average of the highest three hourly demands from the previous 12 months, with the requirement that each of the three hours must occur on different days. Once the customer's service level, ranging from <1 kW for service level 1 to >9 kW for service level 10, is determined, a specific cost for capacity and delivery are assigned.[2176] Mr. Foley added that if a D1.12 customer does not have 12 months of billing history, the company will determine the service level based on the most recent month or months that are available.[2177]

Mr. Foley testified that, based on the company's analysis of the usage history of 10,000 customers, bills for Rate D1.12 customers would be much more consistent, with less than 10% of rate D1.12 customers receiving a high bill (i.e., a bill more than twice as high as the lowest bill), compared to 80% of customers on proposed rate D1.11.[2178] Mr. Foley posited that "[t]his increased bill stability is potentially extremely valuable for customers, such as those on fixed income or otherwise desiring a more consistent electric bill."[2179]

Mr. Foley testified that Rate D1.12 differs significantly from the Fixed Bill programs DTE has proposed in the past, specifically with respect to maintaining near-term pricing signals and the limited risk to other customers if D1.12 customers reduce, shift, or stagger their usage.[2180] Finally, Mr. Foley explained that although DTE is not proposing Rate D1.12 as a pilot program, participation will be limited to 10,000

[2176] At demand levels greater than 9 kW, the service level charge is prorated by 1 kW increments. See, EIBC/IEI brief, 39-40.
[2177] 6 Tr 1157-1158.
[2178] 6 Tr 1161-1162.
[2179] 6 Tr 1162.
[2180] 6 Tr 1163-1164.

customers beginning in Q1 2024, and the company intends to closely monitor participating customers' engagement, usage patterns, and bills under the rate.[2181]

There was no support for the D1.12 Stable Bill proposal among Staff and intervenors. Mr. Revere testified that Staff disagreed with DTE's justification for the rate and recommended that the Commission reject Rate D1.12 as well as the costs associated with its implementation.[2182] Mr. Revere pointed out that "[v]ery few distribution costs are incurred on the basis of an individual customer's demand[,]" adding that Rate D1.12 "does not better reflect cost causation or cost-alignment than the current rate and should therefore be rejected."[2183] MNSC witness Jester testified that "proposed rate schedule D1.12 is the most inefficient and unjust residential rate design that I have reviewed. It would effectively allocate capacity-related and distribution costs to an annually-ratcheted non-coincident customer demand charge based on three hours of the year."[2184] Mr. Jester added that Rate D1.12 would not provide proper price signals to customers to minimize system costs; in fact, the rate would incentivize customers to use power at any time (including system peaks), and it would disincentivize the adoption of level 2 EV chargers, given the high demand of these chargers. This, despite the fact that EV charging typically occurs at night when overall system demand is low. Moreover, according to Mr. Jester, it would disincentivize the adoption of electric heat for the winter, even though system peaks occur in the summer.[2185]

[2181] 6 Tr 1165-1166.
[2182] 8 Tr 5135-5136.
[2183] 8 Tr 5138.
[2184] 8 Tr 3853.
[2185] 8 Tr 3853.

Similarly, MEIBC/IEI witness Barnes stated that the rate design for D1.12 represents "the most thoroughly unsound rate design proposal that I have ever seen proposed from the standpoint of the commonly accepted ratemaking principles such as cost causation, economic efficiency, and revenue sufficiency."[2186] Mr. Barnes characterized the proposed rate as sending an inefficient price signal that could encourage wasteful usage "because the marginal cost of any demand below the fixed service level amount is effectively zero, even if that demand occurs during peak times that drive system costs."[2187] He pointed to his analysis of the same customer group used by Mr. Foley in DTE's evaluation of monthly bill stability, which "indicates that the vast majority of customer demands that determine the service level charge are likely to fall outside of the peak periods that drive the need for generation, transmission, and distribution system capacity."[2188]

In a similar vein, CEO witness Lucas testified:

> The Commission should reject in full DTE's proposed Stable Bill Tariff as it does not comport with standard ratemaking principles. It is not based on cost-causation, is not gradual, and is not actionable. Using a contrived and convoluted demand ratchet called "Service Level," DTE proposes to calculate an individual customer's billing demand level on their three highest use hours in the prior twelve months that fall on separate days. The Service Level, which has little to no bearing on the costs a customer imposes on the system, is then incorrectly applied to all demand-based production, transmission, and distribution costs. The resulting rate design would on average recover two-thirds of revenue through a non-coincident peak charge, and would lock in this portion of the bill for up to twelve months despite any successful efforts for a customer to reduce their demand levels.[2189]

[2186] 8 Tr 4428.
[2187] 8 Tr 4429.
[2188] 8 Tr 4433-4434.
[2189] 8 Tr 3565-3566.

GLREA witness Rafson also recommended that proposed Rate D1.12 be rejected, testifying that implementation of the rate would result in a larger cost recovery than allocated, which would in turn lead to "unjust enrichment for the utilities."[2190]

In rebuttal, Mr. Foley testified that claims by Mr. Revere and Mr. Jester that demand charges are unnecessary or inefficient are insufficient to reject Rate D1.12, noting that demand charges are well-established for large customers, and reiterating that a demand rate provides residential customers with another tool for managing their bills.[2191] In response to claims by several witnesses that Rate D1.12 does not reflect cost-causation, Mr. Foley stated that residential customers do not currently receive any price signal to incentivize managing their demand, and that intervenors suggest "that unless a demand-based charge precisely targets the 4CP, 12CP, and/or class peak hours then it is not cost-aligned. However, precisely targeting these hours is impossible given they cannot be known in advance."[2192] Mr. Foley emphasized that the structure of Rate D1.12 is necessary to provide bill stability, which is important to some customers. Nevertheless, Mr. Foley indicated that DTE was open to implementing TOU demand charges to avoid penalizing off-peak EV charging.[2193]

In response to testimony by witnesses Barnes, Jester, and Lucas concerning ineffective and non-actionable price signals, Mr. Foley reiterated that there is currently no residential rate that encourages management of demand and that "all rate design involves some amount of imprecision and must balance inherent real-world limitations. The important point, however, is to encourage efficient consumption behaviors where

[2190] 8 Tr 3262.
[2191] 6 Tr 1193-1194.
[2192] 6 Tr 1197.
[2193] 6 Tr 1197-1198.

possible."[2194] He added that testimony on the need for constant vigilance by customers on the Stable Bill rate was speculative. Lastly, in response to the claim that Rate D1.12 would result in windfall profits for DTE, Mr. Foley testified that Mr. Rafson misunderstands how revenues are allocated in the COSS and how rates are designed, explaining that "the D1.12 rate is designed to collect the exact amount of revenue allocated to the D1 class through the COSS. In other words, the proposed D1.12 rate is designed to be 'revenue neutral' to the D1 rate such that it would not have any impact on the Company's revenues or profits when compared to the current rate design."[2195]

The parties' briefs and reply briefs rely largely on the record. DTE emphasizes that a voluntary, demand-based rate would give residential customers another option for controlling their energy costs, arguing that "[a] broad pricing signal to manage demand at all times would achieve a higher level of cost-alignment than the status quo."[2196] In its reply brief, DTE reiterates that it would consider alternative demand rate structures, "although any specific application would need to be closely assessed."[2197] In contrast, Staff, MNSC, the CEOs, MEIBC/IEI, GLREA, and others recommend that the proposed rate be rejected, with several parties observing that DTE's rebuttal testimony was inadequate and did not provide an effective response to the many criticisms of the D1.12 rate proposal.[2198]

The PFD agrees with Staff, MNSC, the CEOs, MEIBC/IEI, and others that DTE's Stable Bill proposal should be rejected, and all costs associated with implementing the

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[2194] 6 Tr 1200.
[2195] 6 Tr 1202.
[2196] DTE brief, 249.
[2197] DTE reply, 179.
[2198] See, e.g., CEO brief, 7 and MNSC brief, 109-110.

proposed rate should be disallowed. As multiple witnesses testified, Rate D1.12 is not cost-based; it does not send accurate or actionable price signals to participating customers, and, without constant vigilance, customers could face significant cost penalties for up to one year.

With respect to the lack of COS support for Rate D1.12, the CEO's point out:

> The primary flaw of the D1.12 rate is that the Company designed the rate around an irrelevant focus on individual customer load factor. The Company's rate design places an improper reliance on its . . . ("COSS") in developing rates, by attempting to "translate classwide cost causation principles from the COSS to individual customers". Lucas Direct, 8 TR 3572.
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> The assumption baked into the D1.12 rate is that individual load factors determine "efficient" use of the system. However, the Company's assets are designed to serve many residential customers, not a single individual. Peak demand of any given individual is greatly diluted into the diversified demand that shared distribution and power supply assets serve. Lucas Direct, 8 TR 3574. The Company's cost of service study generally recognizes this, see id at 3574 n. 28, however, DTE departed from this foundational principle when developing the D1.12 rate.[2199]

As for the other flaws in the proposed rate, including inaccurate and non-actionable price signals, this PFD finds persuasive the analyses performed by Mr. Lucas and Mr. Barnes demonstrating that the D1.12 service level charge operates as a one-way demand ratchet whereby customer costs can only increase over a twelve-month period, despite changes in customer behavior that would decrease their demand. The CEOs correctly contend that the arbitrary cutoff in Service Levels could easily result in an unjust and unreasonable rate increase for the unwary customer:

> With each new Service Level reached a customer pays an additional $16.61 per month, U-20836 Rate Design Model for Filing.xlsx, however, as explained in more detail in CEO Witness Lucas's testimony, there is no

[2199] CEO brief, 8-9.

> meaningful difference in the costs on the system between a ratepayer with an average peak load of 4.99 kWh and a ratepayer with an average peak load of 5 kWh. This arbitrary cutoff could penalize a customer who uses a de minimis amount of power at the wrong time. As Witness Lucas explained "[i]n this situation, an inadvertent increase of just 0.01 kW in one of the customer's three peak demand hours could push that customer into the next Service Level. If this customer increased their average hourly load by just 10 watts—roughly equal to toasting bread for 30 seconds—during the wrong hour…" they could be pushed into the next service level. Lucas Direct, 8 TR 3580-81. "The penalty for enjoying a piece of lukewarm bread that hasn't even been properly toasted? A bill increase of $16.61 per month." *Id*.[2200]

Finally, the PFD agrees with MNSC that Rate D1.12 shares many of the key components of DTE's previously proposed fixed bill pricing options that the Commission has repeatedly rejected, finding that bill stability, for those customers who desire it, can be achieved through the company's BudgetWise billing program.[2201] On these grounds as well, DTE's proposed Rate D1.12 Stable Bill should be rejected.

5. Deposit Requirement

MI MAUI and Ann Arbor take issue with DTE's collection of deposits from residential customers.[2202] They object that DTE seeks the maximum deposit permitted under the rules, principally from customers with prior arrearages or without acceptable identification:

> MI-MAUI note that not only is the deposition program imprudent in the amount it costs ratepayers, there are significant social costs of depositions, which disproportionately impact customers already struggling to make ends meet. Thus, both the Company and society should share the goal of minimizing the amount of interest paid on deposits – the Company, because it represents an unnecessary cost, and society,

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[2200] CEO brief, 11-12.
[2201] MNSC brief, 105-109, citing December. 20, 2012 order in Case No. U-17054, page 3 and May 2, 2019 order in Case No. U-20162, page 140.
[2202] MI MAUI brief, 43-53.

> because in doing so, the company places unnecessary financial burdens on its most vulnerable customers.[2203]

MI MAUI and Ann Arbor cite testimony of Ms. T. Johnson as well as Mr. Bunch, and seeks cost disallowances to reflect what they contend is an imprudent assessment of deposits from customers who do not generate arrearages. They argue that the $7.9 million in deposits DTE holds does not protect the company from losses unless the customers with deposits are the customers causing arrearages and they argue that deposits currently held by DTE are in excess of the likely amount of arrearages. In specifically objecting to a deposit requirement for customers without acceptable identification, MI MAUI and Ann Arbor cite applicable rules, R 460.108, R 460.109, and R 460.102(gg), but note the difficulty customers without identification face and that a utility bill is often an alternative means of establishing identification. They argue:

> DTE's decision to apply a deposit to individuals without ID is more similar to cases in which such a practice has been found to be discriminatory on the basis of race and income than it is to those cases in which it has not. If DTE were able to provide information showing that such individuals pose an equal risk as those with a poor payment history, that might prove an effective counter to this concern.[2204]

It argues DTE does not have such information, citing Exhibit MAUI-5.

In its brief, DTE addressed Mr. Bunch's testimony, relying on Ms. Johnson's rebuttal testimony at 5 Tr 835-838:

> 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. [2205]

[2203] MI MAUI brief, 43-44.
[2204] MI MAUI brief, 52.
[2205] DTE brief, 253.

This PFD notes that it is not feasible in the context of a 10-month rate case to consider potential revisions to the Commission rules permitting the collection of customer deposits by utilities, nor does the record in this case establish discriminatory conduct by DTE, or a basis to exclude the deposit program costs from rates. This PFD recommends that the Commission refer an evaluation of the impact of customer deposit requirements on the affordability of service be referred to the Commission's Energy Affordability and Access Collaborative. This PFD further notes that specific concerns with the company's implementation of existing rules may be brought to the Commission's attention through the complaint process.

B. Commercial and Industrial Rates

1. Power Factors

Relying on Mr. Andrews' testimony at 8 Tr 2999-3000, ABATE argues that a credit should be provided to primary voltage customers with a monthly power factor greater than .9, with the credit equal to 0.5% of the billed energy charges. ABATE also objects to an increase in the penalty for customers with a power factor below .85.[2206]

DTE disputes that customer with a power factor above .9 warrant a credit, citing Mr. Willis's and Mr. Revere's rebuttal testimony. DTE argues that Mr. Andrews acknowledged that customers with a power factor below 1 induce losses, and argues that DTE "should not provide credits to customers who continue to induce losses simply because their losses are relatively less than another customer's losses."[2207] DTE also

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[2206] ABATE brief, 74 at n 55.
[2207] DTE brief, 275.

cites Mr. Willis's testimony at 6 Tr 997-998 that the proposed credit threshold is arbitrary.

2. Retail Access Service Rider (RASR)

Mr. Willis proposed three changes to the Retail Access Service Rider tariff.[2208] Mr. Zakem took issue with tariff changes, proposing revisions for greater clarity.[2209] In his rebuttal testimony, Mr. Willis accepted the changes with two additional changes, including a formatting change to capitalize defined terms and adding a reference to the Case No. U-15801.[2210] Through the briefing of the parties, it appears this issue has been resolved, [2211] and the language presented by Mr. Willis at 6 Tr 1002 should be adopted.

3. Rider 3

Mr. Morse testified regarding the Bloom fuel cell energy system and certain DTE Electric tariff provisions for standby service (Rider 3 or R3) that he maintained are a barrier to fuel cell technology adoption in the company's service territory. Mr. Morse described the Bloom technology as "a . . . fuel cell technology platform that generates electricity utilizing an electro-chemical process rather than combustion with its Solid Oxide Fuel Cell (SOFC), and uses the same technology to generate hydrogen from electricity with its Solid Oxide Electrolyzer Cell[.]"[2212] Mr. Morse further explained that:

> Our SOFC systems take in natural gas, renewable biogas, hydrogen or blends of those fuels as the first step in the electrochemical process. When using natural gas or renewable biogas, the system extracts the hydrogen from methane (CH_4) through an internal process called steam

[2208] 6 Tr 1002-1003.
[2209] 8 Tr 4492.
[2210] 6 Tr 1002.
[2211] See Energy Michigan brief, 16; DTE reply, 192.
[2212] 8 Tr 4526-4527.

> reformation. . . . The resulting chemical reaction produces electricity at very high efficiencies of up to 65%, while creating virtually none of the local air pollution associated with combusting fossil fuels[.][2213]

Mr. Morse testified that the Bloom fuel cell system is comprised of 250-300 kW, independently operating modules that do not require routine maintenance and that have demonstrated resilience in even extreme events. He explained that the Bloom fuel cells are generally installed behind the meter, sized to meet the customer's baseload power requirements, and operate in parallel with the utility's distribution system. If the Bloom technology detects a drop in voltage from the distribution system, the system can island and continue to operate until normal grid conditions are restored.[2214]

Mr. Morse testified that the Bloom energy system demonstrates availability above 99%, with a 90% capacity factor, which makes the system attractive to customers who "value sustainability, reliability, resilience and cost predictability[,]" along with higher power quality than is generally available from the distribution system.[2215] However:

> For Bloom Energy systems configured to operate solely in parallel with the utility system, poor utility grid conditions can cause forced outages to occur on the Bloom Energy system through no fault of the Bloom system or customer. In order to protect against power flow back to the grid when the grid is malfunctioning, Bloom Energy systems that are not configured to allow grid-independent operation may have to shut down when tripped by poor grid conditions. If poor grid conditions persist, the shutdown may cause the Bloom Energy System to lose internal heat needed for operation, and result in a longer re-start time for the Bloom Energy system once grid conditions have returned to normal.[2216]

Next, Mr. Morse highlighted the benefits that fuel cell technologies provide to the distribution system, including load modification, reduced need for capacity, energy, and

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[2213] 8 Tr 4527.
[2214] 8 Tr 4528.
[2215] 8 Tr 4530.
[2216] 8 Tr 4533.

ancillary services, and less investment in the transmission and distribution system. Mr. Morse also explained how the Bloom system can function to provide Volt/Var support for changing loads, as an NWA, or in microgrid applications.[2217] Finally, Mr. Morse testified that regulatory commissions in New York and California have adjusted or eliminated standby charges for fuel cell systems, based on COS, recognizing the value that these technologies provide to the grid as well as the high availability and capacity factors associated with these systems.[2218]

Also on behalf of Bloom, Mr. Jester testified that as a best practice, a utility should use a generator's forced outage rate (FOR) in calculating standby charges. Quoting the Energy Resources Center, Mr. Jester explained that use of a standby customer's FOR incentivizes a customer to limit the use of the utility's back-up service and provides a strong price signal that customers should use their generating systems efficiently.[2219] However, citing Mr. Morse's testimony, Mr. Jester reiterated that a standby customer may experience an outage due to conditions outside the customer's control. Mr. Jester noted that in response to discovery, DTE stated that the company does not track the cause of customer outages, or whether the outage was a result of the customer's generator or due to grid conditions.[2220] Thus, according to him:

> [I]t appears that the terms of Rider 3 regarding the calculation of contract capacity and billing demand are applied to customers without regard to whether a customer's on-site generating system's forced outage was caused by DTE itself. Such utility-caused outages can have a significant impact on a customer's contract capacity and/or billing demand, leading to high monthly standby charges through no fault of the customer or the customer's on-site generation. Based on principles of cost causation, such

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[2217] 8 Tr 4534-4535.
[2218] 8 Tr 4536.
[2219] 8 Tr 4544-4545.
[2220] 8 Tr 4546; Exhibit BE-7,

> utility-caused outages should never form the basis of an upward adjustment to a customer's contract capacity or billing demand under Rider 3.[2221]

Next, Mr. Jester addressed the Commission's decisions with respect to R3 in Case Nos. U-18255 and U-20162, which established that the monthly reservation fee for standby service should be based on the FOR of the best-performing generator.[2222] Mr. Jester added, "[s]imilar to the use of a system's FOR in calculating a standby customer's reservation fee, a standby customer's distribution-related demand charges (a.k.a. delivery demand charges under Rider 3) should be pro-rated to reflect the customer's partial and infrequent use of the distribution grid."[2223] Consistent with this testimony, Mr. Jester posited, "In light of the high reliability of many onsite generators, and Bloom Energy systems in particular, the practice of always charging every standby customer full delivery demand charges, with no pro-ration to capture the actual risk or likelihood of an outage, relies on the assumption that all of these customer-owned systems will experience outages at the same time, an assumption that does not reflect operational reality or cost causation principles."[2224] In the absence of a detailed cost study on the use of the distribution grid by standby customers, Mr. Jester recommended "a simple construct" that would prorate the normal demand charge for the number of peak days standby service was used, with an additional charge for distribution facilities that exclusively or primarily serve the standby customer.[2225] For the delivery demand charge for contract capacity, referencing his testimony in Case No. U-20162, Mr. Jester

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2221 8 Tr 4546-4547.
2222 8 Tr 4547-4548, quoting April 18, 2018 order in Case No. U-18255, p. 77 and May 2, 2018 order in Case No. U-20162, p. 152.
2223 8 Tr 4548.
2224 Id.
2225 8 Tr 4551.

recommended that the Commission encourage DTE to provide specific evidence of these costs in future cases, or establish these costs for each customer through a special contract.[2226]

Quoting testimony on avoided transmission and distribution (T&D) costs presented by DTE in Case No. U-20471, Mr. Jester observed that, like EWR, customer-sited generation also contributes to reducing peak loads, which in turn can result in the deferral or elimination of distribution system upgrades. As such, Mr. Jester suggested that the Commission consider avoided T&D costs of $0-$7.00 per KW-year as a reasonable estimate of distribution system design revenue for distribution-connected standby service.[2227]

Mr. Jester made several specific recommendations with respect to Rider 3: (1) the Commission should require DTE to identify and categorize all forced outages experienced by Rider 3 customers as either customer initiated or non-customer initiated; (2) the Commission should require DTE to track all non-customer-initiated outages experienced by Rider 3 customers, and perform a study to identify the cause of these outages, improve distribution grid conditions that may be contributing to the outages, and reduce or eliminate these outages in the future; (3) pending the completion of this study, the Commission should require DTE to suspend the assessment of Rider 3 distribution charges; and (4) the Commission should not permit DTE to adjust a standby customer's contract capacity or billing demand based on non-customer initiated forced outages for four hours after an outage begins.[2228] In addition, Mr. Jester

[2226] Id.
[2227] 8 Tr 4553.
[2228] 8 Tr 4556.

recommended that for customers with modular systems with availability of 90% or more, these customers should be permitted to contract for less than the full capacity of the self-generation system (i.e., for capacity based on one or more, but not necessarily all, of the modules). And he made recommendations consistent with his testimony concerning proration of distribution costs and the incorporation of avoided T&D charges.[2229]

In rebuttal to Mr. Morse, Mr. Willis testified that Bloom's claim that R3 charges are excessive and a barrier to fuel cell technology adoption were presented without COS support, noting that standby rates are not the only consideration in a customer's decision to invest in on-site generation.[2230] In response to recommendations made by Mr. Jester, Mr. Willis testified that DTE does not track the cause of Rider 3 outages, and customers are under no obligation to tell the company why, or even if, an outage occurred. According to Mr. Willis, requiring standby customers to provide this information, as Mr. Jester suggests, could result in the disclosure of sensitive business information. Mr. Willis further pointed out that R3 customers have each experienced one outage per year, on average, over the past five years. Mr. Willis testified that given the privacy concerns, the limited number of Rider 3 outages, and the lack of information about the extent to which grid conditions cause R3 outages, Mr. Jester's recommendations to collect outage data and conduct a study on the cause of outages should be rejected.[2231] Consistent with his objections to an R3 outage study, he also recommended that the Commission reject the recommendation that R3 charges be

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[2229] 8 Tr 4557-4558.
[2230] 6 Tr 980-981.
[2231] 6 Tr 984.

suspended pending the completion of the study. Mr. Willis testified that Rider 3 charges are COS-based, and if standby customers do not pay these charges, other customers will be required to do so.[2232]

Mr. Willis took issue with other changes to R3 proposed by Mr. Jester. First, Mr. Willis explained that Mr. Jester's recommendation to alter the calculation of contract capacity for modular systems was presented without COS support. He added that a self-generation customer with two 250 kW capacity modules could opt for contract capacity based on only one unit, whereas a customer with one 500 kW unit would be required to pay contract capacity for the entire 500 kW. Mr. Willis further noted that, contrary to Mr. Jester's suggestion, R3 reservation charges are already based on the FOR of the best-performing generator. He also objected to changes to the distribution demand charge on grounds that the distribution system is designed to meet customer demands whenever required: "Given this, neither the forced outage rate of a generator nor the timing of those outages is relevant to how distribution charges are designed."[2233] Finally, Mr. Willis recommended that the Commission reject Mr. Jester's proposals related to marginal T&D savings from self-generation, noting that,"[t]he Company does not for any class of customer design distribution rates on marginal costs. The cost-of-service study is not conducted on a marginal basis and retail rate design is not conducted on a marginal basis."[2234]

Staff witness Revere pointed out that Mr. Morse did not quantify the claimed distribution benefits of the Bloom system, nor did he provide a justification for why other

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[2232] 6 Tr 984-985.
[2233] 6 Tr 991.
[2234] 6 Tr 992.

customers should bear the costs that would otherwise be collected from Bloom under current standby rates.[2235] Mr. Revere pointed out that if standby service were not needed, the customer could simply disconnect from the grid; however, "[i]f not disconnected, the utility has to have the equipment in place to be able to serve the demand imposed on the distribution system by the customer."[2236] As such, distribution charges for standby customers are appropriately the same as for other customers, and Mr. Jester's recommendation to prorate distribution charges should be rejected.[2237] Mr. Revere further explained that "the rate does not assume an outage of all customers; rather, it recognizes the difference between power supply and distribution cost-causation, allocation, and rate design."[2238]

Concerning Bloom's claims that capacity cost should be calculated differently for modular systems that demonstrate 90% or more availability, Mr. Revere explained there was insufficient evidence to support the 90% availability benchmark, and it does appear possible that more than one module could be out at the same time. Thus, demand charges should recognize the entire generating system. In response to Mr. Jester's recommendation to recognize non-customer caused outages, Mr. Revere noted that a customer with a Bloom system appears to have a choice to design their system so that outages due to grid conditions can be avoided by disconnecting from the grid. According to Mr. Revere, "[t]he choice of configuration should be laid at the feet of the customer making the choice, not the other customers Bloom witness Jester implies

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[2235] 8 Tr 5156.
[2236] 8 Tr 5156.
[2237] 8 Tr 5156-5157.
[2238] 8 Tr 5157.

should bear the costs that would otherwise be borne by the customer with the Bloom system."[2239]

Staff witness Krause also addressed Mr. Jester's recommendations concerning standby generation and distribution capacity, testifying that while generation capacity may be used by multiple, geographically distant customers, distribution capacity is location and customer specific to a significant extent. Therefore, although proration of standby generation capacity based on FOR may be reasonable and appropriate, it is unreasonable to prorate distribution capacity using FOR.[2240] Mr. Krause further explained that Mr. Jester's proposals are difficult to evaluate given that neither calculations nor a redline version of the R3 tariff were provided. He therefore recommended that the changes to R3 proposed by Bloom be rejected at this time.[2241]

In its initial brief, Bloom reasserts that a generator's FOR should be used both for setting the generation reservation fee and for a customer's distribution-related demand charges, highlighting the infrequent use of the distribution system by the Bloom fuel cell technology.[2242] Bloom references a 2018 case from Pennsylvania wherein a utility proposed to significantly increase its standby distribution rate. The case ultimately settled, and the utility agreed to return to a prorated distribution charge for standby service.[2243]

[2239] 8 Tr 5157.
[2240] 8 Tr 5509-L.
[2241] 8 Tr 5510-L
[2242] Bloom brief, 5-6.
[2243] Bloom brief, 7-8.

Next, Bloom contends that DTE mischaracterized Mr. Jester's proposal for a simplified distribution charge as "preferential treatment."[2244] According to Bloom, Mr. Jester's recommendation simply reflects the reduced usage of the grid by standby customers as well as the benefits that self-generation customers provide to the distribution system like peak load reduction and avoided T&D upgrade costs.[2245]

DTE recommends that the Commission reject Bloom's proposals, reiterating that the utility has no insight into the causes (customer or non-customer) of generator outages, noting that if the distribution system is down, "[t]here are . . . no energy-based billing determinants generated . . . [and] [t]he customer's contract capacity and billing demand will not change when there is a service outage."[2246] In response to Bloom's recommendation to prorate demand delivery charges under R3, DTE disagrees, arguing:

> 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; (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 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).[2247]

Staff's brief summarizes Mr. Revere's and Mr. Krause's rebuttal testimony to specific claims made by Bloom's witnesses. Staff emphasizes the differences between

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[2244] Bloom brief, 8-9 quoting 6 Tr 989.
[2245] Bloom brief, 9.
[2246] DTE brief, 272.
[2247] DTE brief, 273-274.

power supply and distribution cost-causation, allocation, and rate design methods, arguing that while proration based on FOR may be appropriate for generation capacity, it is not reasonable for distribution costs.[2248]

In its reply brief, Bloom argues that it is unjust to require R3 customers to pay costs associated with outages caused by company equipment failures, adding that Bloom does not advocate that DTE collect sensitive business information in determining the cause of an outage. Bloom notes that DTE could simply provide R3 customers an opportunity to report the cause of an outage, suggesting that, "[i]t does not seem credible that DTE would be unaware of when its own system failure occurred, thus causing an outage at a customer site, as it is responsible for correcting such outages."[2249] Bloom points out that the small number of R3 customers actually supports a requirement that DTE undertake a study of R3 outages and Bloom's recommendation that the company suspend standby charges until the study is completed. Bloom reiterates that standby charges are not cost-based if the company cannot identify outages that are not customer-caused.[2250]

Finally, in response to Staff and DTE, Bloom reiterates that standby distribution charges should recognize the limited use of the grid by highly reliable systems, like the Bloom technology, in addition to the grid-related benefits these modular systems provide.

This PFD agrees with DTE and Staff that Bloom's recommendations concerning changes to Rider 3 should be rejected at this time. Specifically, the PFD finds that

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[2248] Staff brief, 254-257.
[2249] Bloom reply, 3.
[2250] Bloom reply, 4-5.

Bloom's reference to non-customer caused outages was unclear and could potentially apply to outages that were not caused by DTE (or the customer). Thus, a study to determine and classify self-generation outage causes is not supported on this record. In addition, as Mr. Willis explained, if the distribution system is down, standby customers are not billed for service.

The PFD also agrees with Mr. Revere that R3 power supply rate is already discounted "to recognize the unique nature of service to standby customers, including the diversity amongst those customers and how that lowers the generation required to serve them."[2251] Further, the PFD agrees that proration of distribution demand charges is not appropriate, for the reasons set forth in Mr. Krause's and Mr. Willis's testimony. That said, the PFD finds that in the company's next rate case, DTE should be directed to provide a proposal to reduce the reservation fee for fuel cell systems, based on FOR for these systems, or provide a justification for why it would be unjust or unreasonable to do so.

4. Rider 10 Administrative Charge

Ms. Crozier discussed DTE's proposed reduction to the R10 administrative charge, testifying that "[t]he Rider 10 pricing structure is unique in that these customers have an interruptible service for which the Company's R10 class is designated as a capacity resource within the MISO Resource Adequacy Construct (unlike non-interruptible customers) and have a significant portion of their power supply rate based

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[2251] 8 Tr 5156.

on the real time MISO locational hourly marginal energy price."[2252] As such, Ms. Crozier explained:

> [T]he Rider 10 class cost responsibility for power supply should be different than other customer classes. I have instructed Company Witness Ms. Asghar to provide a 50% credit to the Rider 10 class contribution to Allocation Schedule 100 (Power Plant Energy Production). This credit will reduce the R10 class power supply cost responsibility and thereby reduce the R10 Administrative Charge calculated by Company Witness Mr. Willis.[2253]

In addition to a reduction to the administrative charge, Mr. Farrell testified that DTE proposes to modify the non-interruption penalty from the current $50 per kW applied to the highest hour interruptible demand created during the interruption period, to the higher of the current penalty or the actual damages incurred by the company, including MISO penalties.[2254] Mr. Farrell explained that the proposed modification will ensure that if actual costs for non-interruption are higher than the current penalty other customers will not be required to subsidize non-performance penalty costs associated with R10.[2255]

Mr. Farrell explained that there is not an approved method for distributing non-interruption penalties, although, "under performance penalties in recent events have been allocated to . . . PSCR customers as a credit."[2256] Going forward, DTE proposes to first assign penalty revenues to PSCR customers so that they are held harmless for any MISO costs allocated to PSCR. Then, any remaining funds would be used to improve DR programs including investments in IT, customer communication

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[2252] 7 Tr 2357.
[2253] 7 Tr 2357.
[2254] 7 Tr 1696.
[2255] 7 Tr 1696-1697.
[2256] 7 Tr 1697.

improvements, marketing, and education for DR participants. Mr. Farrell noted, however, that DTE would not seek a DR financial incentive for DR program spending paid for by non-interruption penalties.[2257]

On behalf of Gerdau, Mr. Pollock echoed Ms. Crozier's description of R10, reiterating that, unlike Rate D11, R10 is a fully interruptible, market-based rate, and that all energy supplied to R10 customers is obtained from the wholesale market. Mr. Pollock underscored that as an interruptible rate, DTE Electric does not need to provide any zonal resource credits (ZRCs) to serve R10 load.[2258] Thus, "R10 customers neither utilize nor directly benefit from DTE's generation."[2259]

Quoting from the tariff, Mr. Pollock testified that R10 customers currently pay an administrative charge of 1.676¢ per kWh, which, as noted above, the company proposes to decrease to .775¢ per kWh.[2260] According to Mr. Pollock:

> The current administrative charge was derived from the compliance CCOSS approved in DTE's last electric rate case (Case No. U-20561). Specifically, R10 was included as a separate customer class, and it was allocated a portion of DTE's production non-capacity costs. The R10 class's share of production non-capacity costs was the result of applying the four coincident peak (4CP) - 75%/0%/25% Average Demand (75/0/25) method, but with the R10 4CP demand allocator set to zero. This resulted in allocating $90.7 million of production non-capacity costs to the R10 class. Of this amount, R10 customers paid $60.3 million of MISO charges and voltage adder charges. This left $30.4 million of costs recovered in the administrative charge. The current administrative charge, thus, was derived by dividing the $30.4 million of remaining DTE production non-capacity costs by the test-year R10 sales.[2261]

2257 7 Tr 1697.
2258 8 Tr 3727-3729.
2259 8 Tr 3727.
2260 8 Tr 3727
2261 8 Tr 3732.

Mr. Pollock testified that the term "administrative charge" is misleading because the costs of administering R10 are collected through the same Service and Distribution charges paid by all D11 customers.[2262] Mr. Pollock noted that in the past (until December 31, 2015) the administrative charge was set at .54¢ per kWh but has increased ever since.[2263] Although Mr. Pollock agreed that the proposed reduction in the R10 administrative charge was appropriate, the rate design for R10 in this case nevertheless "continues to assume that R10 customers are either served by or directly benefit from DTE's generation fleet and therefore should pay a portion of the costs of that fleet."[2264] He summarized:

> There is no cost basis for either the current or proposed R10 administrative charge. The energy serving R10 customers is procured in the wholesale market, and R10 customers receive no benefit from the revenues produced by DTE's generation sales. Thus, R10 customers are neither served by nor do they directly benefit from DTE's generation fleet. These facts, coupled with the fact that R10 is a fully interruptible service, mean that no DTE generation costs (capacity or energy) are attributable to R10. Further, any customer service, billing, and administrative costs are fully recovered from R10 customers in the applicable Service and Distribution charges. For these reasons, the so-called administrative charge should be eliminated.[2265]

Mr. Pollock added that if the complete elimination of the administrative charge in this proceeding were found to be too extreme, the Commission should nevertheless begin phasing out the charge in this case.[2266]

On behalf of ABATE, Mr. Dauphinais provided an overview of the history of R10 noting that the rate was first approved in the May 21 and November 6, 1992 orders in

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[2262] 8 Tr 3732.
[2263] 8 Tr 3734.
[2264] 8 Tr 3735.
[2265] 8 Tr 3740.
[2266] 8 Tr 3741.

Case No. U-10090.[2267] Mr. Dauphinais discussed the evolution of the original "stacking" approach to allocating fuel and purchased power costs to R10, which to some extent relied on DTE generating resources. He pointed out that the January 13, 2009 order in Case No. U-15244 significantly altered the structure of R10, adding a Power Supply Pricing option while retaining the stacking option for customers that elected to use that rate.[2268] Subsequently:

> The foregoing changed when the Commission issued an order on December 15, 2015 in Case No. U-17767 that had major implications to R10 and its customers. Specifically, in its December 15, 2015 Order in Case No. U-17767, the Commission eliminated the traditional "stacking" approach under R10 and required all R10 load to use the Power Supply Pricing Option.
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> In addition, when this change was implemented, the allocation of a share of DTE's production plant costs and non-fuel production O&M costs to the R10 class was maintained and its recovery redirected from the discontinued R10 Power Supply Generation Capacity Charge, which had only applied to R10 customers using the traditional "stacking" approach, to the R10 Administrative Charge, which applies to the Power Supply Pricing Option. As a result, for the first time since the institution of the Power Supply Pricing Option in January 2009, R10 customers using that option were assigned an allocation of DTE's production plant costs and non-fuel production O&M costs even though, under the Power Supply Pricing Option, R10 load does not tangibly benefit from DTE's generation facilities or cause DTE to incur any generation costs.[2269]

Citing industrial competition, recent inflationary pressures, and a 29% decline in R10 sales, Mr. Dauphinais testified that the company must take action "to reform DTE's Administrative Charge to bring it into alignment with cost of service" to avoid the additional loss of R10 and D11 customers, which could cause rates to increase for other

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[2267] 8 Tr 2906-2907.
[2268] 8 Tr 2912.
[2269] 8 Tr 2913.

customers.[2270] Accordingly, Mr. Dauphinais testified that ABATE fully supports DTE's proposal to reduce the R10 administrative charge in this proceeding calling it "an important first step" toward making R10 COS-based.

Finally, Mr. Dauphinais addressed prior Commission determinations and DTE's opposition to eliminating the R10 administrative charge on the basis that R10 customers benefit indirectly from DTE's generation through lower and less volatile MISO LMPs.[2271] Mr. Dauphinais pointed out that the claimed effect on MISO market prices is intangible and has not been quantified. Moreover, "to the extent there is such a claimed benefit, it is also received by all of the retail open access customers within DTE's service territory, including those whose Alternative Electric Suppliers self-supply capacity, as well as likely all retail and wholesale electric customers located within MISO Local Resource Zone 7 . . . but outside of the DTE service territory."[2272] Yet, according to Mr. Dauphinais, DTE's ROA customers and other purported beneficiaries of DTE's generation are not paying any of the costs associated with the company's resources.

Although Staff did not address the R10 administrative charge in direct testimony, Mr. Doherty testified that Staff agreed with the company's proposed change to the non-interruption penalty. However, Mr. Doherty objected to DTE's proposal to use excess penalty revenue to enhance the company's DR programs as Mr. Farrell suggested. Mr. Doherty recommended that DTE continue to credit excess penalty revenue to PSCR customers, stating Staff's concern that "[t]he allocation of any excess revenues should not be left solely to the Company's discretion for use on something as relatively vague

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[2270] 8 Tr 2915-2916.
[2271] 8 Tr 2919-2920.
[2272] 8 Tr 2923.

and undefined as improving demand response programs without prior input from Staff and other parties."[2273]

In its brief, Gerdau provided an overview of the history of the R10 administrative charge, highlighting that under the previously available stacking approach, R10 customers did rely to some degree on DTE's generation resources, thus the allocation of some production costs was appropriate. However, once the stacking approach was eliminated, DTE's generating resources were no longer used for R10, resulting in an administrative charge that is no longer cost-based, and thus should be removed. Similarly, ABATE contends that the Commission should approve DTE's proposal to reduce the R10 administrative charge in this case, noting that no party opposed the proposal, and the Commission should instruct DTE to remove the charge entirely in its next rate case.[2274]

Staff states that based on the record in this case, it agrees with Gerdau and ABATE that R10 customers do not benefit from DTE's generation resources, thus, "the R10 class should not be allocated production plant and non-fuel production O&M costs in allocation schedules 100 and 200A."[2275] Staff also agrees that DTE's proposal to reduce the administrative charge in this case should be approved and that DTE should eliminate the charge entirely in its next rate case.

Concerning the company's proposal to use excess non-interruption penalties to enhance or improve DR programs, Staff reiterates that DTE should not have unfettered

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[2273] 8 Tr 5531.
[2274] ABATE brief, 71-72.
[2275] Staff brief, 238.

discretion to apply penalty revenue to DR programs without oversight. As such, the current method of crediting PSCR with excess penalty revenue should be maintained.

This PFD agrees with Gerdau and ABATE that the R10 administrative charge is an artifact from the time when the stacking method, which did rely to a degree on DTE generating resources, was available under R10. As these parties and Staff conclude, because the stacking method was eliminated in 2015, and because R10 customers are fully interruptible and rely solely on the MISO market for energy, the R10 administrative charge is no longer cost based. Accordingly, the PFD finds that DTE's proposal to significantly reduce the charge in this case should be approved, and the Commission should direct the company to eliminate the charge in its next general rate case.

Turning to the company's changes to the non-interruption penalty, this PFD notes that no party objected to DTE's proposed modification to the penalty, and this PFD agrees that the company's proposal addresses the potential for subsidization of non-compliant R10 customers by other customers. The PFD also agrees with Staff that the company's plan to allocate penalty funds above the amount required to offset actual PSCR costs to unspecified DR programs should be rejected. As Staff points out, there is a process in place for evaluating DR program proposals to ensure that program spending is reasonable and prudent. DTE's request to use the funds from R10 penalties as the company sees fit, would unnecessarily circumvent this process.

5. Rider 18

DTE presented two proposals for modification of its DG program (Rider 18) going forward.[2276] First, DTE proposes to change the inflow rate by requiring all new DG customers to take service under Rate D1.12. Second, the company proposes to alter the outflow credit to the average MISO hourly locational marginal price (LMP) for the appropriate DTE node (calculated separately for each pricing period for customers taking service on TOU rates), plus a credit for avoided line losses based on the company's most recent line loss study. DTE states that "these changes to Rider 18 [will] 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."[2277] If both inflow and outflow modifications are approved, DTE agrees to voluntarily raise the cap on its DG program to 3.0% of the company's average in-state peak load for full-service customers during the previous five calendar years. In addition, DTE would not enforce category-specific capacity limits reserved for each DG size category as provided in MCL 460.1173(3).[2278]

In addition to proposals made by DTE, Staff and several intervenors made recommendations concerning the DG program. The various proposals are addressed below.

[2276] See, Exhibit A-16, Schedule F7, pages 1-3.
[2277] DTE brief, 260-261,
[2278] 6 Tr 1169, 1182-1185.

a. Inflow Rate

DTE proposes that new DG customers enrolling in Rider 18 be required to take service under Rate D1.12. According to the company:

> 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).

For the reasons discussed at length above, this PFD recommends that the D1.12 Stable Bill tariff be rejected. In addition, the PFD agrees that the specific proposal to mandate Rate D1.12 for new DG customers should be rejected for the many reasons outlined in testimony and briefing by Staff and intervenors.[2279] As the CEO summarize:

[2279] See, e.g., GLREA brief, 23: ("DTE's proposal violates the Company's own rate design principle of "optionality". . . . We also noted that for DG customers, this would also violate the Company's rate principle of incrementalism, . . . subjecting these customers to a dramatic change."); DAAO brief, 90: ("DTE's proposal to decrease compensation and impose heightened costs on its DG customers exacerbates the current program's unaffordability problems, further excluding low income residents and residents of color from the program. The proposal seeks not only to cut the outflow credit but also to impose new system fees."); Staff brief, 248, 249: ("[T]he Company's proposal actually removes 'optionality' from DG customers." "[C]ost shifts occur anytime a customer changes their usage in a way that is not exactly reflected in the allocations to the class, such as customer reducing their usage through participation in . . . (EWR) programs, or any number of other reasons, while still relying on the same equipment to serve them."); MEIBC/IEI brief, 48: ([MEIBC witness] Barnes notes that the effects of the rate on Rider 18 DG customers would likely be so punitive as to cause them to 'pay more for electric service than they would pay on another available residential rate without installing a DG system.'"); MNSC brief, 128: ("DTE's DG proposal discriminates against QFs by undercompensating for outflow and deterring competition with its MIGreenPower program. DTE has also failed to show that the cost of service for DG customers is so different, or that they are otherwise so differently situated from other residential customers, that they require they would not pay appropriate revenue under the 'prevailing residential customer tariffs.' Because DTE has not justified requiring DG customers (and those customers alone) to take service under this unattractive tariff, the Commission should reject DTE's proposal that all

> [T]he D1.12 rate standing alone is an unjust and unreasonable rate, that applies an unprecedented, punitive demand ratchet to residential customers. These critiques can be applied with the same force to the requirement that new [distributed photovoltaic] DPV customers take service under the D1.12 rate. However, there are also a number of concerns unique to DPV customers that make the rate even more unreasonable. Furthermore, the Company's justification for its requirement is based on an unsupported "cost shift," that fails to value the many benefits of DPV. The Company's "cost shift" is a cry for revenue it believes it is owed, framed slightly differently, and falls apart under scrutiny.
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> The Commission has previously rejected DTE's attempts to apply a punitive charge to DPV customers, and the D1.12 rate should be rejected for the same reasons. In Case U-20162, the DTE 2018 Rate Case, the Company proposed a "system access charge," that similarly charged DPV customers for avoided distribution related costs. In U-20162, the Commission found that the system access charge was "neither COS-based…nor equitable…the utility's method for calculating the SAC charge explicitly relied on the distribution revenue deficiency and not on any cost to serve…. The Commission finds that this does not comport with the statutory requirement and is unreasonable from a COS ratemaking perspective." DTE Electric Co., Case No. U-20162, Order at 198 (May 2, 2019) (internal citations omitted). The D1.12 rate relies on a similar justification and operates in a similar fashion, and should be similarly rejected by the Commission.[2280]

Staff recommends that DG customers be allowed to take service under rate D1.8 (Dynamic Peak Pricing). Mr. Revere testified that "even though the rate is considered to be a demand response rate, with pricing set to encourage certain behaviors, the pricing is still justified by cost-differentials (such as the appropriate way to charge for power supply capacity I discussed earlier). Therefore, the pricing is also appropriate for DG customers and their outflow."[2281]

Rider 18 customers must use D1.12 for inflow.") and MI MAUI/Ann Arbor brief, 39: ("As Witness Wu's analysis of an actual customer's data shows, if DTE's D1.12 proposal were approved as proposed, a residential customer with rooftop solar who chose not to use DTE's grid would be charged $118/mo more than a customer without rooftop solar.").

[2280] CEO brief, 30-31. See also, Staff brief, 248-249; MNSC brief, 125-128; DAAO brief, 87-88, 91-92; MEIBC/IEI brief, 48-51; GLREA brief, 22-24; and MI MAUI/Ann Arbor brief, 39-43.

[2281] 8 Tr 5141.

In rebuttal, Mr. Willis testified that Mr. Revere accurately described the nature and purpose of Rate D1.8, as a DR rate designed to encourage customers to shift usage from on-peak to off-peak periods by increasing the power supply rate from $0.16 per kWh during on-peak hours to $0.95 per kWh during critical peak events.[2282] However, according to Mr. Willis, the critical peak rate is designed as "[a] mechanism to drive behavior change and response – it is decoupled from a direct alignment to temporal costs and is not governed by a benchmark differential like D1.11."[2283] As such, Mr. Willis testified Rate D1.8 is not appropriate for compensating outflow, noting that the outflow credit under D1.8 would be approximately 10 times the current outflow credit, "[with] no plausible avoided cost basis."[2284] Mr. Willis further noted that Rate D1.8 cannot be combined with certain other tariffs, riders, or services, thus the limitation on the rate does not uniquely exclude DG.[2285]

Staff does not respond to the company's rebuttal in its initial brief; it reiterates its position that DG customers should be permitted to participate in Rate D1.8. In its initial brief, GLREA agreed with Staff's proposal.[2286]

The PFD agrees with DTE that the purpose of Rate D1.8 is to encourage participating customers to shift their usage from on-peak to off-peak periods and, unlike TOU rates, Rate D1.8 is not cost-based. Therefore, Staff's proposal should be rejected at this time. Staff may consider presenting a more developed rationale for its recommendation in a future rate case.

[2282] 6 Tr 972-973.
[2283] 6 Tr 973.
[2284] 6 Tr 974.
[2285] 6 Tr 973.
[2286] Staff brief, 186; GLREA brief, 7.

b. Outflow Rate

As outlined above, DTE proposes to change the current outflow rate, which is based on power supply less transmission, to one based on monthly average LMP. Mr. Foley criticized the current outflow credit as inconsistent, observing that a DG customer on standard rate D1 would receive an on-peak outflow credit of $0.0775 per kWh, whereas a DG customer on a TOU rate would receive a credit of $0.1533 per kWh for the same energy produced at the same time.[2287] To address this disparity, Mr. Foley testified that DTE proposes that the DG outflow credit be based on "quantifiable costs," positing that the company's proposal ensures that costs to the utility for outflow are passed on to DG customers; it provides flexibility if the DG program grows, and it provides consistency across the program.[2288]

Mr. Foley explained that the quantifiable cost impacts from DG outflow are related to reduced energy market purchases by DTE and to avoided T&D line losses. He further testified that DG customers "have no obligation, contractual or otherwise, to provide capacity to the Company[,]" noting that customers may flow excess energy to the system after serving their own load, or they may use excess energy to charge a battery. "As such, there is no expectation nor obligation of total outflows, outflows during a given period, or a portion of DG system capacity dedicated to outflow[,]"[2289] thus, DG customers are more appropriately compensated for energy only sales, as

[2287] 6 Tr 1170-1171.
[2288] 6 Tr 1171.
[2289] 6 Tr 1172.

Rider 5 customers are compensated.[2290] According to DTE, its proposal for outflow compensation:

> . . . 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.[2291]

Staff recommends that the outflow credit for Rider 18 customers be established at power supply plus transmission.[2292] Mr. Revere testified that compensating DG customers based on LMP, as DTE suggests, "ignores the reality of the Company's power supply costs that would be offset by the outflow of DG customers, thereby undercompensating DG outflow. As retail rates represent the Company's actual power supply costs as charged to customers, they are more appropriate."[2293] He added that DTE's averaging of LMPs does not reflect the temporal value of DG outflows. Mr. Revere also testified that because DG outflow is supplied at the distribution level, it offsets transmission usage, and therefore transmission should be included in the outflow credit. He noted however, that while this is a reasonable starting point, because of the way transmission costs are assessed and how they are allocated, including transmission in the outflow credit, "likely does not fully encompass the contribution outflow has towards reducing the use of transmission."[2294]

[2290] 6 Tr 1172-1174.
[2291] DTE brief, 260, citing 6 Tr 936 and 6 Tr 1170-1177.
[2292] 8 Tr 5510.
[2293] 8 Tr 5139.
[2294] 8 Tr 5140-5141.

Staff witness Matthews agreed that although DG customers are under no obligation to provide capacity to DTE, the company nevertheless uses DG capacity in its load forecast. As such, Mr. Matthews testified that "[w]ith the reduced load forecast from the inclusion of the DG program, it lowers the capacity requirement from the Company. This gives the Company a value, that it does take into account when performing its load forecast."[2295] MEIBC/IEI, MNSC, the CEO, and GLREA, among others, agree with Staff's recommendation that outflow compensation should recognize both capacity and avoided transmission values.[2296]

GLREA recommends that the outflow credit be applied to distribution portion of the customer's bill as well as the power supply portion. Mr. Richter pointed out that outflow energy produced by DG systems generally flows to neighbors nearby, thereby reducing distribution costs to the utility.[2297] GLREA urges the Commission to direct the Staff to undertake a study to determine the portion of delivery costs should be included in the outflow credit.

GLREA also recommends that the company should be required to purchase the renewable energy credits (RECs) produced by DG systems under Rider 14, Rider 18, and any successor program, and transfer the RECs to DTE's voluntary green pricing program (VGP) provided under Rider 17. Mr. Richter recommended that RECs from DG customers be priced at 80% of the premium Rider 17 customers pay for renewable energy under that tariff. Staff endorses GLREA's recommendation concerning the

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[2295] 8 Tr 5384.
[2296] See, e.g., MEIBC/IEI brief, 55-56; MNSC brief, 132; CEO brief, 40, 43-44; GLREA brief, 18; DAAO brief, 90-91.
[2297] 8 Tr 3182.

purchase of RECs, noting that it will add value to the DG program and reduce costs for the VGP program. Mr. Matthews testified:

> If the Commission approves this proposal, Staff recommends the Commission direct DTE to work with interested intervenors to finalize new Rider 18 tariff language addressing the REC purchase activity and REC purchase pricing. DTE could then file the revised tariff in this docket, requesting ex parte approval within 90 days of the final order in the instant case.[2298]

Relying on Mr. Lucas's testimony, the CEO recommend a COS approach to determining outflow credit. Mr. Lucas explained that he focused his analysis on the load factors of DG customers before and after installation of a DG system in comparison to non-DG customers. Mr. Lucas posited that although use of a load factor for an individual customer was inappropriate for a demand rate (i.e., Rate D1.12), "[w]hen applied to a group of customers, the load factor reflects a measure of efficient use of the system. In the context of outflow energy or net energy from a DPV customer, the load factor provides some insight on the relative reduction in demand that is associated with the corresponding reduction in energy."[2299] The results of Mr. Lucas's analysis demonstrated that DG installation significantly increases the load factor for the DG customer group. According to Mr. Lucas, "This means that on a per kWh basis, the demand reduction from self-consumed DPV generation far exceeds the embedded demand reductions from the residential class as a whole."[2300]

Based on his analysis of post-DG installation load factors, and his calculation of the marginal benefit of capacity, energy, and transmission compared to non-DG customers, Mr. Lucas computed an outflow credit of $0.12311 per kWh, which he

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[2298] 8 Tr 5291.
[2299] 8 Tr 3639.
[2300] 8 Tr 3640.

recommended be applied to Rider 18 outflow as the most equitable cost-based figure presented in this proceeding.

The PFD finds that Staff's proposed outflow credit should be adopted,[2301] along with GLREA's recommendation that DTE purchase RECs from DG customers and apply those RECs to the VGP program. As Staff and several intervenors point out, using an average of LMP over all hours, as DTE proposes, effectively dilutes the value of DG, which typically produces energy during peak hours. Moreover, this PFD finds persuasive Staff's concern that because LMP would not be known before outflow occurs, DG customers would not receive actionable price signals. As Mr. Krause testified:

> If the customer knew that the value of the outflow was low, they may choose to shift load into that period of time and use more generation behind the meter. Similarly, if the customer knew the value of the outflow was high, they may choose to shift load out of that time period in order to export more. The issue here is that the credit for the outflow is not known until well after events have occurred and decisions have been made. The situation becomes even more dramatic if the customer's system also includes storage. Decisions for when to charge, and when to discharge need to have clear price signals. Even if these decisions are automated such that customer intervention is not required in these decisions, the decisions are still based on price signals that if not known at the time would need to be projected. This is beyond the reasonable expectation of most if not all residential customers.[2302]

In addition, this PFD disagrees with DTE's claim that because DG customers are not obligated to provide capacity, these customers should not be compensated for any capacity they might provide. It is clear the DTE does in fact recognize DG capacity in its

[2301] MEIBC/IEI supports Staff's outflow credit proposal. See, MEIBC/IEI brief, 51-54.
[2302] 8 Tr 5509-5510.

load forecast, as several witnesses pointed out. Thus, capacity from DG systems provides a cost savings to the company.

DTE criticizes Staff's outflow recommendation, reiterating that the differences in underlying rate schedules result in different outflow credit amounts, which Mr. Foley characterized as "a clear deficiency in the current Rider 18 design."[2303] DTE also argues that credit for avoided transmission is inconsistent with the Commission's decision in Case No. U-20162, which excluded transmission from outflow credit; there is little offset to transmission cost associated with DG, and including transmission would conflict with MCL 460.1177(4).[2304]

The PFD disagrees. First, DTE does not rebut evidence that although the Commission did approve Staff's proposal to set outflow credit at power supply less transmission in Case No. U-20162, it did so "based on the evidence in [that] case."[2305] Moreover, the Commission made clear that:

> Section 6a(14) provides the Commission with broad discretion to adopt a DG tariff "reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or a distributed generation program," and finds that the Staff's proposed outflow credit meets the requirements of the statute. The Commission additionally agrees with the ALJ's findings of fact and conclusions of law regarding the inapplicability of MCL 460.1177(4) as it relates to this inflow/outflow methodology and the statutory charge for the Commission to establish a tariff reflecting equitable COS for DG customers.[2306]

Lastly, the PFD agrees with Staff that differences in outflow credit amounts do not reflect a deficiency in Rider 18, but simply demonstrate the options DG customers have

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[2303] 6 Tr 1220.
[2304] MCL 460.1177(4) provides: "Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges."
[2305] May 2, 2019 order in Case No. U-20162, page 180.
[2306] May 2, 2019 order in Case No. U-20162, page 180.

for inflow rates. Thus, DTE's objections to Staff's outflow recommendation should be rejected.

DTE also maintains that GLREA's proposal regarding REC purchases from DG customers "is ill-timed and inappropriate in this case. The discussion of updated Rider 17 would be appropriate in the Company's Section 61 proceedings."[2307] DTE cites the recent settlement in Case No. U-20713, which modified Rider 17. This PFD disagrees that requiring the purchase of RECs from DG customers is particularly ill-timed or otherwise inappropriate to address here, noting that the changes to Rider 17 eligibility and structure have no impact on how the company acquires green energy, which could be purchased at a discount from DG customers under Rider 18. The PFD therefore recommends that the Commission adopt Staff's suggestion that DTE work with interested stakeholders to revise Rider 18 to reflect the purchase of RECs, and that the company be directed to submit an application for *ex parte* approval within 90 days of the date of the Commission's order.

Turning to the recommendations by the CEO and GLREA concerning outflow credit, the PFD agrees with Staff that the CEO recommendation, as set forth by Mr. Lucas, relies on treating DG customers as a separate class, which the Commission has consistently found to be inappropriate. Moreover, as Mr. Krause testified:

> Outflow is not just inflow in reverse in terms of cost causation. There is no such thing as negative energy. Energy flowing in reverse may or may not offset costs that are allocated on energy. There should be no blanket assumption that it either does or does not offset those costs. Every allocated item should be looked at for what it is, and it should be evaluated with regard to whether or not it is offset by self-generation. For example: does outflow offset fuel for generation? Or tree trimming expense? Are

[2307] DTE reply, 193.

> these impacts properly captured by the reduced allocations currently utilized? Mr. Lucas never provides any justification for why outflow reduces cost causation he just presumes that it does and uses that as a basis for his calculation.[2308]

Turning to GLREA's recommendation to compensate DG customers for purportedly reduced distribution cost, the PFD also agrees with Staff that outflow is purchased by DTE at the meter as a source of supply, and the energy must still be delivered to customers using the company's distribution system. Moreover, DG customers are already compensated for reduced distribution costs through reduced inflow.[2309]

Lastly, Mr. Willis testified that for primary customers taking service on a demand rate, DTE proposes to establish the outflow credit on the basis of the average on-peak outflow demand, and for secondary customers, the company proposes to base outflow on the average of monthly outflow billing demand.[2310] Mr. Revere testified that Staff supports DTE's recommendation for primary customers but disagrees with the company's proposal for secondary customers. Mr. Revere explained:

> The outflow demand credit is effectively intended to recognize the value of the outflow provided by customers on the DG tariff with reference to the Company's costs and rates. The relevant costs are incurred over the on-peak period, so that is the manner in which both secondary and primary demand billed customers should be credited.[2311]

As discussed above, the PFD agrees that utility costs are driven by on-peak usage and therefore DG outflow credit should reflect the fact that DG systems typically generate on-peak.

[2308] 8 Tr 5510-C.
[2309] Staff brief, 188-189.
[2310] 6 Tr 937.
[2311] 8 Tr 5140.

c. Other Proposals

MEIBC/IEI, MNSC, the CEOs, and GLREA recommend that the Commission establish a successor tariff to Rider 18, to take effect once the cap on the DG program is reached, including detailed proposals for a post-cap DG program.[2312] DTE objects on grounds that existing Rider 5 and Rider 14 allow DG customers to interconnect their systems once the cap is reached, thus, "[t]he Company is not offering, and does not support, the creation of any additional tariffs involving customer generation."[2313]

The PFD agrees that a just and reasonable, post-cap DG tariff should be developed. As several parties point out, DG systems are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act and, as such, DTE is obligated to purchase QF power at the utility's avoided cost. However, given the time constraints and number of issues that need to be addressed in this rate case, a successor tariff to Rider 18 should be referred to a separate proceeding. Accordingly, the PFD recommends that the Commission direct DTE to file, within 90 days of the date of this order, a proposed tariff for DG post-cap, including Rider 5 or Rider 14 if DTE believes these programs to be reasonable successors to the current DG program.[2314] Other interested parties may intervene and advocate for what they consider appropriate costs and credits for DG systems once the 1% cap is reached.

[2312] See, e.g., MEIBC/IEI brief, 59-61.
[2313] DTE brief, 267, quoting *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997).
[2314] DTE should also be directed to address the conflict between MCL 460.6 ("The public service commission is vested with the power and jurisdiction to regulate all rates, fares, fees, charges, services, rules, conditions of service, and all other matters pertaining to the formation, operation, or direction of public utilities[,]") and the company's contention that the creation of a successor tariff would invade management prerogative under *Ford Motor Co., supra*, or *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988).

C. Voluntary Green Pricing (Community Solar Tariff)

DAAO and Staff both presented recommendations that DTE provide opportunities for community solar projects. Ms. Baldwin testified to limitations on the ability of broad categories of customers to participate in the DG program. She testified:

> The community solar pilot would make solar power available to customers who are currently unable to participate in the DG program due to living in multi-family dwellings, commercial customers located in multi-unit commercial buildings, customers with sites which are not appropriate for distributed generation projects, or customers who are otherwise unable to install an on-site distributed generation project, including due to lack of financial resources. Participating customers would subscribe to a portion of a solar project. Similar to customers participating in DTE's DG program, a participating customer would cause a solar project to be constructed based on their commitment to pay their share of the solar project development and operation costs pursuant to a contractual arrangement. The benefits of participation include directly causing additional solar projects to be constructed and the potential for the cost paid for the solar energy to become less than the subscriber DG credit in the future.[2315]

Ms. Baldwin also explained the critical role that a subscriber organization would play in development and implementation of a community solar project:

> A subscriber organization is responsible for project financing, construction (construction could be contracted to a solar developer), operation, and managing subscriptions. Staff is proposing that, like the DG program, a solar project under the community solar program would not be owned by a utility. The community solar contract and pricing would be subject to a private agreement between the subscriber organization and the participating customer. However, to address customer protection concerns, Staff recommends a set of requirements be met by subscriber organizations who wish to participate in the community solar pilot program.[2316]

DAAO discuss the important grid, environmental, accessibility, and community benefits of community solar projects to fill a gap in DTE's exhibits programs, including a

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[2315] 8 Tr 54498-5449.
[2316] 8 Tr 5451.

low-income solar pilot.[2317] DAAO cites the testimony of Mr. Koeppel and Mr. Donovan, explaining that community solar provides a solar energy solution that particularly supports low-income ratepayers and ratepayers of color, emphasizing the benefits of a community ownership option:

> [B]ecause community ownership is central to community solar, community solar produces several community-based benefits. Residents can leverage their power-producing assets to generate savings and wealth for themselves and for their local community—savings and wealth that circulate locally rather than into shareholders' pockets. Moreover, community solar customers can also gain a wealth of knowledge in the "management and governance of a significant and meaningful community-based resource." Lastly, community ownership over solar puts energy decisions into the hands of the communities, allowing them to make decisions that best benefit their own community and not just the utility companies.[2318]

DAAO cites a comprehensive plan that Soulardarity submitted in DTE's recent Voluntary Green Pricing case, Case No. U-20713. It argues that if DTE does not adopt that plan, it should alternatively adopt a modified version of the pilot proposed by Staff in this case, also explaining the modifications that should be made.[2319]

DTE's rebuttal testimony focused on the difficulty of approving a community solar program in this case. Ms. Crozier testified:

> While the proposal on pages 6 – 15 by Staff Witness Baldwin for a community solar pilot outlines interactions and responsibilities for the various pilot participants (DTE Electric, participating customers, and subscriber organization), the short time between Staff's testimony and rebuttal is insufficient for the Company to perform a proper assessment of the pilot as proposed. The Company and other interested parties would benefit from the opportunity to weigh the costs and benefits of this pilot compared to pilots with similar goals agreed to in the Company's last

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[2317] DAAO brief, 103-117.
[2318] DAAO brief, 107-108.
[2319] DAAO brief, 111-113, 115-116.

> voluntary green pricing (VGP) (MCL 460.1061) filing in Case No. U-20713.[2320]

She also objected that no determination regarding the incremental costs of administering the program could be determined at this time.[2321] Ms. Crozier noted that DTE currently has low-income solar pilots approved as part of its VGP program, which were also discussed by Staff and DAAO witnesses. She testified that DTE does not believe adding additional pilots is beneficial but she did further indicate that although DTE is skeptical:

> [T]he Company does agree that discussions with a select group of parties would be helpful in reconciling which of the proposed and current pilots might best inform the potential for future programs. The Company's upcoming August 2022 VGP filing would be a good place to start those conversations. However, there is not enough time between now and August for the Company to complete those discussions and develop any additional pilots or modifications of current pilots for inclusion in that VGP filing. Thus, at a minimum, the Company proposes that the conversation be advanced in that upcoming VGP filing and potentially developed enough for proposal in the next rate case.[2322]

DTE's briefs make essentially the same points.[2323]

Staff addressed Ms. Crozier's rebuttal in its brief, arguing that the Commission should approve the limited 5 MW pilot program Ms. Baldwin described.[2324] Staff notes differences between the current VGP pilots and its community solar pilot proposal, but further states:

> Staff agrees with Ms. Crozier's determination that there is not enough time between now and the Company's August 2022 voluntary green pricing filing to include this community solar pilot program in that case. Ms. Crozier proposes that more discussion of the program occur in the August

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[2320] 7 Tr 2384.
[2321] 7 Tr 2385.
[2322] 7 Tr 2387.
[2323] DTE brief, 275-276; DTE reply, 194-195.
[2324] Staff brief, 203-204.

> 2022 VGP case for potential inclusion in the next rate case. (7 TR 2387.) This recommendation aligns with Staff's alternate recommendation if the Commission opts not to approve the community solar pilot program.[2325]

DAAO objects to delaying creation of a pilot, and also disputes that there is insufficient time for DTE to develop a proposal in its August 2022 voluntary green pricing program filing.[2326]

This PFD acknowledges that it is not feasible to design a community solar pilot project in the confines of a 10-month rate case. After reviewing the testimony and arguments presented, however, this PFD is convinced that a logical first step toward enabling such a pilot is to create a facilitating tariff. Given the connection of a community solar program to the VGP program, this PFD recommends that the Commission require DTE to amend its Rider 17 Voluntary Green Pricing tariff to provide for such programs to be developed and offered through the VGP program. MCL 460.1061 states in key part:

> An electric provider shall offer to its customers the opportunity to participate in a voluntary green pricing program under which the customer may specify, from the options made available by the electric provider, the amount of electricity attributable to the customer that will be renewable energy. If the electric provider's rates are regulated by the commission, the program, including the rates paid for renewable energy, must be approved by the commission. The customer is responsible for any additional costs incurred and shall accrue any additional savings realized by the electric provider as a result of the customer's participation in the program.

Based on the testimony presented in this case, it is clear that a community solar option has the potential to address deficiencies in current VGP offerings for low-income customers, as well as the limitations on DG participation for customers who live in multi-

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[2325] Staff brief, 204.
[2326] DAAO reply, 14-17.

unit dwellings or commercial customers located in multi-unit commercial buildings. While Ms. Baldwin described certain program parameters, such as the maximum size of the pilot and the potential for distribution credits in addition to other credits, and Mr. Koeppel made related alternative recommendations, this PFD does not find the record sufficient to make such detailed determinations without the context of specific projects. Instead, to facilitate the development of community solar programs through the VGP program, this PFD recommends that the Commission require DTE to revise the Rider 17 tariff to permit the utility to offer customers who are subscribers of a community solar organization the opportunity to participate in the VGP under terms and conditions agreed to by DTE and the subscriber organization, with approval of the MPSC under MCL 460.1061. The tariff should be drafted to permit a program meeting the description in Exhibit S-17 and as described by Ms. Baldwin. This tariff provision will not require any action by DTE to implement the tariff at this point, but will facilitate the development of pilot programs in the VGP proceedings. DTE should consult with Staff and stakeholders in the development of the tariff language, as Staff recommends.[2327] The Commission should also expect DTE to fulfill its commitment to engage in discussions regarding community solar piloting in its now-ongoing VGP case.

[2327] Staff brief, 202. While DAAO objects to *ex parte* filings, Staff's proposal makes clear that a contested case should be available if stakeholders dispute the filing.

XII.

FUTURE RATE CASES, FURTHER STUDY

The parties made several recommendations that the Commission require DTE to take additional actions before or in connection with its next rate case. Some of the parties recommendations were addressed as necessary in some of the discussion above. To the extent feasible, additional requests are addressed in this section.

Several parties raise concerns that DTE did not adequately address equity considerations in its distribution spending plan in this case, notwithstanding commitments to equitable principles in its DGP.

To the extent feasible, this PFD addresses some of the parties' recommendations below.

A. Equitable considerations in distribution planning

MNSC, the CEO,[2328] DAAO, and Staff[2329] raised concerns that DTE's proposed strategic capital expenditures in this case did not consider or did not adequately consider principles of equity, with several witnesses citing a mismatch between the discussion of equity in the company's DGP and its proposals in this case. For the most part, these concerns lead the parties to seek Commission action targeted at future improvements, performance-based ratemaking, and rate design modifications rather than seeking specific rate adjustments to distribution spending.

One recommendation common to Staff, DAAO, MNSC and the CEO is the need for broader evaluation of alternatives to address the 4.8kV system and the increasingly

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[2328] See CEO Brief, p. 68.
[2329] Staff brief, 280-282.

compelling need to upgrade that system to support a modern grid. This PFD recommends that the Commission adopt some form of these parties' recommendations, and in particular, in view of the deficiencies and costs associated with the two-track hardening and conversion work DTE is undertaking, direct DTE to confer with stakeholders and to research potentially feasible alternatives to achieve grid conversion sooner and at a lesser cost, and to evaluate alternative prioritizations that take grid equity metrics into consideration.[2330] This should include an evaluation of opportunities to seek federal funds or alternative sources of funding for distribution system upgrades.

Staff has additional concerns that DTE's investments miss the broader impact of equitable and resilient electric infrastructure.[2331] In hopes of alleviating these concerns, Staff recommends the Commission: (1) adopt definitions for equity and related metrics for the energy infrastructure it regulates so all interested parties have a common understanding, (2) require the Company to include future analyses, like overlay maps, charts, graphs, and other displays, that provide a visual or data-informed understanding of more holistic impacts of electric infrastructure investments on customer communities in future rate cases and distribution plans, and (3) request the Company work with Staff and interested stakeholders on a case study on the impact of socioeconomic data analysis in its next rate case.[2332] This PFD finds Staff's recommendation reasonable and consistent with the commitments in the company's DGP and with Ms. Pfeuffer's commitments in this case, including work with the MIEJ Screen tool.[2333]

[2330] See DAAO brief, p. 118.
[2331] See Staff Brief, p. 280.
[2332] See Staff Brief, p. 282.
[2333] 4 Tr 505-521.

B. Other distribution planning concerns

In addition to recommendations that DTE focus future planning efforts on equity concerns, some parties raise additional concerns with DTE's distribution system planning process. For example, MNSC recommends that DTE voluntarily make several changes to its Distribution Grid Plan (DGP) to better support its distribution system investments. MNSC recommends that DTE should replace its assessment of asset health based largely on age statistics with one more thoroughly based in reliability and repair theory, that DTE should optimize its monitoring and inspection programs to support equipment replacement based on conditions indicating incipient failure, and that DTE should include the rate impact of each category of spending and for the plan as a whole as part of its next DGP.[2334] The CEO renews their call for a contested case review of the DGP, or at minimum, seek to ensure a sufficient link between the proposals and goals associated with the DGP and the ensuing rate case that implements the Company's investment strategies.[2335]

While some of these concerns were noted above, this PFD notes that the Commission recently issued an order in Case No. U-20147, which further addressed the distribution planning process and considered comments from several parties who are also parties to this case. In view of the extensive discussion in the Commission's order, this PFD does not find that further recommendations not specific to DTE proposed or planned projects would be helpful.[2336]

[2334] See MNSC Brief, pp. 162-167.
[2335] CEO brief, 62.
[2336] September 8, 2022 order, Case No. U-21047.

This PFD also notes that DAAO and others have argued for an increase in outage credits.[2337] This PFD concludes that in light of the Commission's recent outage credit rules, it is beyond the scope of this PFD to address the recommendations.

C. Classification of emergent capital expense

In its order in Case No. U-20561, the Commission expressed a concern regarding the company's classification of costs to the emergent replacement category and its capitalization of costs:

> But beyond the issue of inflation, the Commission is concerned with getting a better understanding of what expenses are assigned to this category, particularly in light of DTE Electric's arguments regarding strategic capital (discussed below). To that end, the Commission directs 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, and directs the Staff to provide an analysis of the expenditures that are capitalized in this category.[2338]

In light of this order, Staff and MNSC raise concerns regarding the assignment of costs to "emergent" categories and raise additional concerns with the capitalization of certain costs and with the allocation of repair costs between capital investment and removals.

Mr. Becker explained the conceptual distinction between "emergent" spending on equipment that has failed and "proactive," planned spending "aimed at improving reliability by strengthening the system."[2339] He also cited another portion of the Commission's order in Case No. U-20561, in which the Commission explained that it does not view emergent capital spending as interchangeable with strategic capital spending:

[2337] See DAAO brief, 52-54.
[2338] May 8, 2020 order, page 86.
[2339] 8 Tr 5403.

> The Commission is primarily concerned with the lack of detailed information regarding what expenditures are assigned to the emergent replacements category and, as discussed above, has directed the Staff to analyze that capitalized expense category in the company's next electric rate case. The Commission also disagrees with DTE Electric's view that DO capital expenditures should be treated as a single entity, putting, for all practical purposes, strategic capital and emergent replacements in the same bucket. This would erase the intended "strategy" of strategic capital – to improve future reliability and resiliency, and reduce risk.[2340]

Mr. Becker testified that to monitor performance between the two programs from year to year, it is important that expenses be properly classified. He considered expenses in the "substation reactive—non-electrical work" subcategory, not directly related to generation or transmission, to be strategic.[2341] He cited Exhibit S-15.3 in testifying that "equipment deemed to be at risk of imminent failure" is captured under emergent replacements and the company does not track equipment identified as at risk of imminent failure that is not replaced.[2342] Mr. Becker recommended that the Commission require the following, beginning with DTE's next rate case:

> 1) The Company shall begin tracking equipment identified as imminent failure (near failure but has not failed) and exclude those costs from the emergent replacements capital program.
>
> 2) The Company shall revisit the emergent replacements capital spend program currently used and re-assign, where necessary, spend that does not align with the purpose of emergent replacements.
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> 3) The Company shall revisit the customer connections, relocations & other and strategic capital spend programs currently used and re-assign, where necessary, spend that aligns with the purpose of emergent replacements.[2343]

[2340] May 8, 2020 order, page 91.
[2341] 8 Tr 5403-5404.
[2342] 8 Tr 5404.
[2343] 8 Tr 5404-5405.

Ms. Pfeuffer testified in rebuttal, disagreeing that replacing equipment deemed at risk of imminent failure is better classified as strategic rather than emergent spending.[2344] She testified that replacements on imminent failure are those performed by field personnel:

> [W]hen field personnel determine that equipment is at risk of imminent failure, they initiate emergent replacements to the latest construction standard, but without the full planning and engineering that would go into a strategic replacement. These imminent failure replacements are necessary reactive, unplanned work to prevent customer outages prevent safety incidents, and/or prevent any additional damage to the electrical system where equipment has been identified as being in a damaged and abnormal state.[2345]

She specifically discussed the substation reactive—non-electrical line item:

> The non-electrical substation equipment that is replaced under this category is necessary to maintain the integrity and safety of the electrical equipment within the substation. Without the proper non-electric infrastructure and safeguards at the substation, the electrical equipment cannot be safely maintained and operated to serve the customers. An example of this type of work would be the replacement of a failed substation gate or fencing. While not a part of the electrical distribution system, this infrastructure is necessary to protect the electrical equipment and keep the public safe from contact with energized equipment. These replacements are also completed without initiating a long-term strategic project to significantly change the design or layout of the substation.[2346]

She disputed that DTE should track imminent failure replacements, characterizing it as unnecessary and testifying that it would require "significant adjustments to the work management system and work tracking process that includes additional training and time requirements for field personnel."[2347]

[2344] 4 Tr 495.
[2345] 4 Tr 495.
[2346] 4 Tr 496497.
[2347] 4 Tr 497.

DTE relies on Ms. Pfeuffer's rebuttal in opposing Staff's proposed requirements.[2348] In its brief, Staff addresses Ms. Pfeuffer's rebuttal testimony in its brief:

> Staff is not in a position to explicitly identify where mis-categorized expenditures should be, nor does it intend to imply that substation reactive – non-electrical equipment spend should be classified under strategic capital. The Company should determine the appropriate program in the next electric rate case after its review. Staff's analysis is to solely identify areas of improvement to align with the Company program's purpose and goals of the Commission to improve overall reliability of the system in a proactive manner that aims to reduce outages and unplanned spend. Staff also agrees witness Becker did not clearly identify the impacts of what Staff believes is a mis-categorization of emergent versus strategic investments; however, the Commission's Order in U20561 speaks for itself. The Commission undeniably wants to ensure the emergent replacements and strategic capital programs are appropriately organized and aligned with their purpose to permit careful monitoring of spend in the future and track progress towards strengthening the system, improving reliability, and reducing risk.[2349]

This PFD recommends that the Commission direct DTE to work with Staff on a format for the disclosures that Staff wants to see, taking into account the limits of DTE's current record keeping, with the expectation that DTE will report the agreed-upon information in its next filing and discuss those Staff requests it is not able to address.

D. Capitalization Practices

As discussed in the rate base section above, Staff and MNSC raised concerns with DTE's accounting for certain expenses. Staff raised a concern in connection with both distribution system capital spending and IT capital spending. MNSC raised concerns in connection with the distribution system. Staff recommends the Commission order the company to convene with Staff and interested parties to evaluate the

[2348] DTe brief, 47-48.
[2349] Staff brief, 275.

company's current capitalization procedures as they relate to the capitalization of pole inspection and testing spend and provide additional information in the Company's next electric rate case.[2350] Staff further recommends that the Commission order DTE to: 1) provide a thorough breakdown of the total pole inspection/test costs applied across all capital programs/subprograms; 2) support why these costs are appropriately classified as capital instead of O&M with reference(s) to accounting guidance; and 3) amend the classification of these expenditures in the company's next rate case, where necessary, based on the analysis.[2351] Regarding IT and IT-related expenses, Staff also raised a concern that the company is not following its capitalization policy, and is capitalizing maintenance, monitoring, and routine upgrades.

In its brief, MNSC explained Mr. Ozar's concerns, including his recommendation that the Commission require DTE to submit detailed information in its next care related to its accounting for inspections and for the tree trimming it performs in connection with its hardening and its pole and pole top maintenance and modernization program.[2352] In addition, MNSC cited Mr. Ozar's concern regarding the 80/20 allocation between installation and removal costs DTE uses for distribution system replacements.[2353] MNSC supports Staff's request for a stakeholder group to evaluate the company's accounting in these regards, arguing that MNSC should be included in any such stakeholder group.

As noted above, in her rebuttal testimony, Ms. Uzenksi's agreed that a discussion with Staff would be worthwhile but objected to including other interested

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[2350] See Staff brief, 276-279.
[2351] See Staff brief, 276.
[2352] MNSC brief, 87-93.
[2353] See MNSC brief, 93-94.

stakeholders. MNSC addressed this testimony, noting Mr. Ozar's analysis and expertise, and argued that including interested stakeholders is not likely to prove overwhelming.

Citing Ms. Uzenski's testimony, DTE states in its brief that it agrees to file reports supporting the capitalization policies relating to inspection costs questioned by Staff and MNSC.[2354] In its reply brief, it add that there is no need for Staff's suggestion that Staff and potentially other stakeholders should meet or for the Company to provide additional information, regarding capitalization policy.[2355] It does subsequently state that it would be willing to meet with Staff on the issue.[2356]

With reference to the discussion in the rate base section of this PFD, this PFD concludes that DTE has not demonstrated clarity or transparency regarding its capitalization policies, and finds the issues identified by Mr. Becker, Mr. Ozar, and Dr. Wang rise to a sufficiently significant level that the Commission should either require the reporting and stakeholder group that Staff requests, or elevate this matter to the level of an official Commission investigation of the company's accounting. These capital expenditures, increasingly difficult to review in 10-month rate cases, total for distribution and IT system spending alone approximately $1 billion in 2020, with the company's projected test year capital expenditures in these two areas equal to more than $1.5 billion.[2357]

[2354] DTE brief, 66
[2355] DTE reply, 42.
[2356] DTE reply, 98.
[2357] Exhibit A-12, Schedule B5.

E. Performance Based Ratemaking

Several parties were expecting DTE to propose a performance based ratemaking mechanism in this case. Ms. Pfeuffer testified that DTE did not commit to providing a performance-based ratemaking proposal in this case, but did include a discussion of performance-based ratemaking in its DGP, Schedule M1 of Exhibit A-23. She explained:

> The Company agreed to provide a PBR proposal in the next rate case following the conclusion of case U-20147. The Company is awaiting an Order from the Commission on the PBR plan included in its DGP. I do not believe that it would have been productive for the Company to propose a PBR mechanism in this rate case prior to receiving Commission feedback clarifying the appropriate parameters.[2358]

CEO recommends that the Commission provide DTE the "guidance" it requests on its preliminary performance-based ratemaking plans, and after providing feedback, the Commission should require DTE to file its performance-based ratemaking plan within 180 days.[2359] This PFD instead recommends that the Commission advise DTE that it will consider performance-based ratemaking proposals from all parties in DTE's next rate case, along with testimony regarding any proposal put forward by DTE.

F. Contributions in Aid of Construction

In DTE's last electric rate case, Case No. U-20561, MNSC[2360] proposed changing DTE's CIAC policy to limit DTE's allowance for new customer connections, in order to alleviate excessive increases to rate base and what it considers a cross-class subsidy.[2361] Specifically, MNSC recommended "that the Commission approve a

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[2358] 4 Tr 529-530.
[2359] See CEO Brief, p. 68.
[2360] In the order in Case No. U-20561, MNSC was referred to as "the MEC Coalition."
[2361] See, May 8, 2020 order in Case No. U-20561, pp. 183-186.

payback period of 4.5 years for distribution revenue and that the contributions in aid of construction (CIAC) policy be changed to limit DTE Electric's contribution to 4.5 times the estimated annual distribution revenue from the customer, rather than the average 8.2 year payback period used under the current CIAC policy.[2362]

In its final order, the Commission declined to adopt this proposal, instead directing DTE to substantiate the reasonableness of its current CIAC policy by providing the following in its next rate case:

> (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.[2363]

Mr. Willis specifically addresses items (1), (2), and (3) in his testimony.

In support of DTE's current CIAC model, Mr. Willis compared MNSC's proposal in Case No. U-20561, limiting DTE's contribution to 4.5 times the estimated annual distribution revenue from the customer, to DTE's current allowances offered via the two times annual margin method and standard allowance table.[2364] Mr. Willis analyzed 90 unique projects between 2018 and 2020 and found that if MNSC's proposal had been implemented, its surveyed customers would have incurred approximately $20 million more in upfront costs on the aggregate.[2365] Additionally, Mr. Willis found that after reviewing a 600 kWh per month residential customer, the result of implementing MNSC's proposal would have been a 15% decrease in CIAC allowances for residential

[2362] See, May 8, 2020 order in Case No, U-20561, pp. 95-96.
[2363] See May 8, 2020 order, Case No. U-20561, page 98.
[2364] See 6 Tr 954-958.
[2365] See 6 Tr 957-958.

customers.[2366] As to the Commission's inquiry about whether the CIAC model is COS based, Mr. Willis offered similar evidence utilizing the two times annual margin method and the standard allowance tables discussed above, stating that the cost is anchored in COS principles.[2367] Finally, Mr. Willis provided evidence that revenue from new connections helps offset other customer costs by providing three examples where this is the case: (1) a standard CIAC allowance provided to a customer is fully recovered over the contract term, with the remaining margin beyond the contract term going to fixed costs; (2) the new customer contributes to Nuclear Surcharge and Energy Waste Reduction, thereby reducing costs to other customers; and (3) a new customer contributes equally to O&M expenses and lowers costs.[2368] Mr. Willis testified that each of these examples stand for the proposition that new customer load will continue to contribute to the utility fixed costs after the term associated with the allowance.[2369] Additionally, in regards to the issue of how new customer connections drive upgrades to the system, Mr. Robinson testified that new customer connections will results in upgrades that benefit the new customer as well as those customers on the same circuit.[2370]

Mr. Ozar recommended that the Commission reject the current CIAC policy based, in part, upon the same reasoning MNSC has presented in prior DTE and Consumer Energy rate cases, namely that current CIAC policy creates a cross-class

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[2366] See 6 Tr 958-959
[2367] See 6 Tr 959.
[2368] See 6 Tr 960.
[2369] See 6 Tr 960.
[2370] See 9 Tr 1574.

subsidy.[2371] While conceding that changing the structure for new line extensions drew strong objections from some members of the CIAC Workgroup, Mr. Ozar proposed that an alternative approach be explored via continuation of the Staff CIAC workgroup[2372]. Specifically, Mr. Ozar recommended that revenue requirements associated with the utility's contribution toward line extensions (net rate base) be split in two:

> (a) the revenue requirements of line extension allowances that are attributed to projected distribution revenue (pursuant to the existing CIAC formulas) should continue to be allocated as in current policy (assigned to distribution revenue requirements and recovered in distribution; and(b) the revenue requirements of line-extension allowances attributed to projected power-supply revenues (capacity and energy) should be assigned to power-supply revenue requirements, and recovered in power supply charges (note that allowances vary pursuant to the CIAC table for customers with load greater than 1000 kW).[2373]

Mr. Ozar explained that should the Commission agree with the preceding approach, new customers will still see the same allowances toward line extensions as under current policy, but rates will more accurately reflect the line extension allowances available to each rate class.[2374]

DTE objected to the proposed change. Mr. Willis presented rebuttal testimony contending that the change in CIAC policy would inappropriately recover credits for investments in distribution through power supply rates.[2375] Mr. Willis explained that the credits for line extensions are meant to support investment in distribution (transformers,

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[2371] See 8 Tr 4035.
[2372] See 8 Tr 4036-4037.
[2373] See 8 Tr 4036-4037.
[2374] See 8 Tr 4037.
[2375] See 6 Tr 996.

conductions, poles, and protections), and therefore should not be recovered in the power supply portion of the revenue requirement.[2376]

In its brief, MNSC argues that DTE failed to meet the directives in U-20561, as it did not provide substantial support of the current CIAC model, failed to provide supporting data as to how new customers will contribute to both distribution and power supply, and its survey of 90 unique projects regarding CIAC distributions fails to address the issue of distribution plant costs being recovered in distribution rates for years by DTE's rate base.[2377] In its reply brief, MNSC also addresses the issue of how new customer connections drive upgrades to the system, stating that Mr. Robinson's testimony does not address new customers and fails to explain how this new circuit is helpful to new customers.[2378]

DTE relies on Mr. Willis and Mr. Robinson's testimony in its briefs.[2379] DTE disagrees there exists any need to reform its current CIAC policy; however, DTE would presumably participate in any continuation of the CIAC workgroup, provided the CIAC workgroup is not simply driven by MNSC's preferences.[2380]

On January 15, 2022, the CIAC Workgroup Report was released, and the positions outlined by DTE and MNSC were discussed. In the report, Staff noted that it had not taken a position in either recent Consumers or DTE rate cases where CIAC reform was proposed, and Staff stated it remains skeptical on this issue of what

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2376 See 6 Tr 996.
2377 See MNSC brief, pp. 114-120.
2378 See MNSC reply brief pp. 8-9.
2379 See DTE brief pp. 100-104
2380 See DTE reply brief, pp. 84-85

revenues to include in line extension deposits.[2381] The CIAC Workgroup provided several recommendations to the Commission for considering CIAC policy in the future, including: (1) further consider updating the cost per foot of line extensions presented in tariffs, as whatever data used to create this allowance is likely obsolete; (2) only change CIAC policy in general rate cases and not standalone proceedings due to the influence such a change could have on the revenue requirement, rates, and individual customers; and (3) continue CIAC workgroup meetings to further develop known issues and allow new proposals to be submitted and discussed.[2382]

This PFD finds that Mr. Ozar's recommendation to explore his proposal via continuation of the Staff CIAC Workgroup to be reasonable. Because the CIAC workgroup itself recommended that it continue to meet and further develop known issues and new proposals, this would appear the most appropriate outcome for MNSC's alternative proposal. Considering the significant effects of any change to CIAC policy could have on revenue requirements and dates, it would appear that the CIAC Workgroup is the most appropriate venue to review this proposal in-depth. It is not feasible to fully evaluate these changes in a 10-month rate case, although the workgroup appeared to agree that any changes should ultimately be adopted in a general rate case.

In making this recommendation, this PFD also notes MI MAUI and Ann Arbor are concerned with the determination of CIAC for streetlighting programs, and with DTE's

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[2381] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000001keFvAAI.
[2382] Id.

accounting for the revenues provided as CIAC. This PFD recommends that these concerns also be evaluated through that workgroup.

G. Alternative Distribution Pilots

MNSC also urges the Commission to require DTE to study and report on two techniques for distribution system management. The first is a recommendation to evaluate continuous distribution monitoring systems, including a substation-installed device called "Distribution Fault Anticipation" (DFA), based on Mr. Ozar's testimony at 8 Tr 4023-4029.[2383] While Ms. Pfeuffer in her rebuttal seemed to indicate that DTE agrees on the importance of this technology, MNSC is concerned that DTE's reference to "machine learning" does not reflect an appreciation or understanding of the technology Mr. Ozar was discussing. MNSC cites additional discovery from DTE that causes its concern. This PFD recommends that, in lieu of directing any particular study, the Commission direct DTE to confer with MNSC so that it has an understanding of the technology at issue and can consider that as part of what it considers an ongoing evaluation of new technologies. This PFD notes DTE's objection to conducting this and other pilots recommended by MNSC, citing *Union Carbide*.[2384] While this PFD is not recommending that the Commission require DTE to conduct a pilot, only to gain an understanding of the potential of the technology Mr. Ozar recommends for consideration, the Commission may want to remind DTE that it has an obligation to establish that its projected capital and O&M distribution system maintenance and

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[2383] MNSC brief, 157-161.
[2384] DTE reply, 125.

improvement expenses are reasonable and prudent, which requires that it show that it has considered reasonable alternatives to its own proposals.

MNSC also urges the Commission to require DTE to evaluate a variable tree trimming cycle as described by Mr. Ozar at 8 TR 4030-34, arguing:

> Mr. Ozar recommended that the Commission require the Company to immediately initiate a pilot to test such an optimization approach for trimming based on circuit characteristics, and to file a report detailing the results, both in terms of reliability benefits and cost savings. The Company declined to rebut this recommendation, so the Commission should adopt it.[2385]

In its reply brief, DTE argues that it is not necessary for the Commission to direct a pilot because "the Company continues to explore opportunities to improve efficiencies in the Tree Trimming program, including considering the benefits that may come from a variable cycle."[2386] This PFD finds the company's representation should be sufficient to resolve this issue, with the company expected to provide an update on its analysis in its next rate case.

H. Electrification Pilot

MNSC also urges the Commission to adopt Mr. Neme's recommendation that the Commission adopt a pilot to consider opportunities to promote the use of electricity in lieu of propane, kerosene, and fuel-oil for home heating in its service territory. Citing Mr. Neme's testimony at 8 Tr 4085-4114, MNSC argues:

> Witness Neme recommends that while DTE and interested stakeholders should develop the program design details, the pilot DTE proposes to the Commission should have the "principal purpose" to "test how to drive significant demand for cold climate heat pumps and identify and address

[2385] MNSC brief, 153-154.
[2386] DTE reply, 141.

> the market delivery challenges what [sic] will arise when there is such demand."[2387]

MNSC lists five principles that should govern the pilot.[2388] DTE objects to any such pilot, again citing *Union Carbide.*[2389] Recognizing the difficulty of directing the company to undertake a pilot that it does not wish to undertake and has not designed, this PFD instead recommends that DTE explicitly evaluate the potential increase in demand that may be anticipated from the increasing availability of heat pumps relative to the cost of alternate heating systems as part of its sales and monthly peak demand forecasts in future rate cases and in its upcoming IRP.

I. CVR/VVO reporting

Citing Mr. Evans's testimony at 8 Tr 5434, Staff asks that the company provide the following information as part of its next rate case: 1) actual and projected capital expenditures for CVR for every year from 2019 through the test year; 2) actual and projected O&M expenses for CVR for every year from 2019 through the test year; 3) annual energy savings; 4) cumulative energy savings; 5) annual customer cost savings; 6) cumulative customer cost savings.[2390] DTE does not object to Staff's proposal, and it appears reasonable.

XIII.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions, and recommendations set forth above, including the

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[2387] MNSC brief, 154.
[2388] MNSC brief, 154-155.
[2389] DTE reply, 125.
[2390] Staff brief, 47.

findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses leading to an estimated revenue deficiency of approximately $145.7 million, with an authorized return on equity of 9.9% and an overall cost of capital of 5.42%, as well as recommendations regarding various accounting requests, cost of service allocations, and rate design, and including recommendations for additional Commission investigation, and additional utility reporting and analysis.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by: Sharon L. Feldman
DN: CN = Sharon L. Feldman email = feldmans@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2022.09.19 14:38:29 -04'00'

Sharon L. Feldman
Administrative Law Judge

Issued and Served:
September 19, 2022

Michigan Public Service Commission
DTE Electric Company
Projected Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending October 31, 2023
($000)

Case No.: U-20836
PFD
Appendix A

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projectior (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Rate Base	Exh. A-12, Sch. B1	$ 21,242,782	$ (776,550)	$ 20,466,232
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	$ 912,824	$ 89,516	$ 1,002,341
3	Overall Rate of Return	Line 2 ÷ Line 1	4.30%	0.60%	4.90%
4	Projected Rate of Return	Exh. A-14, Sch. D1	5.56%	-0.14%	5.42%
5	Income Requirements	Line 1 x Line 4	$ 1,180,249	$ (71,589)	$ 1,108,660
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	$ 267,425	$ (161,105)	$ 106,319
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	$ 360,926	$ (217,433)	$ 143,492
9	Revenue Deficiency - Tree Trim Surge Program	Exh. A-11, Sch. A1.1	$ 7,021	$ (4,833)	$ 2,188
10	Revenue Deficiency / (Sufficiency)-Total	Line 8 + Line 9	$ 367,947	$ (222,266)	$ 145,680

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Incremental Revenue Requirement
Projected 12 Month Period Ending October 31, 2023
($000)

Case No.: U-20836
PFD
Appendix A.1

Line No.	(a) Description	(b) Reference	(c) Applicant Projection	(d) PFD Adjustment	(e) PFD Projection
1	**Return on Tree Trim Regulatory Asset**				
2	Average Balance Regulatory Asset	Line 16	108,160	-	108,160
3	Deferred Tax Liability	- Line 2 x 25.9% Composite Tax Rate	(28,013)	-	(28,013)
4	Average Net Rate Base		80,147	-	80,147
5	Authorized Rate of Return	DTE permanent pre-tax v. Staff short-term debt rate U-20561.	8.76%	-6.03%	2.73%
6	Return on Tree Trim		7,021	(4,833)	2,188

Line No.	Description	2019-A	2020-A	2021	2022	2023	
7	**Tree Trim Regulatory Asset**						
8	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	-	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges thru April 30, 2020 1/	-	1,200				
10	Additional Funding Request	-	-	-	-	67,000	Exhibit A-13 C5.6.1, Line 3
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	314,300	Cumulative Line 11
13	Approved for Securitization 2/			(156,900)	(156,900)	(156,900)	Case U-21015 Exhibit A-3
14	Cumulative Balance at December 31			32,200	90,400	157,400	
15	Cumulative Balance at October 31				72,320	144,000	Assumes 80% of annual spend
16	Average Balance					108,160	

1/ Interest at U-20162 authorized STD rate of 3.56% until U-20561 order was in effect.

2/ Securitization approved per U-21015 order dated June 23, 2021 (up to $156.9 per order page 91)

Michigan Public Service Commission
DTE Electric Company
Projected Rate Base
Projected Average Balances Period Ending October 31, 2023
($000)

Case No.: U-20836
PFD
Appendix B

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projection (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	25,082,094	(723,891)	24,358,203
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	66,804	-	66,804
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	1,524,799	-	1,524,799
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	95,879	-	95,879
6	Total Utility Plant	Sum Lines 2 thru 5	26,769,577	(723,891)	26,045,685
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(6,928,981)	(52,658)	(6,981,640)
8	Net Utility Plant	Line 6 + Line 7	19,840,596	(776,550)	19,064,046
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	16,402	-	16,402
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	-	-	-
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	155,492	-	155,492
12	Total Utility Property and Plant	Sum Lines 8 thru 11	20,012,490	(776,550)	19,235,940
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L75 + L90	19,036	-	19,036
14	Net Plant	Line 12 - Line 13	19,993,454	(776,550)	19,216,904
15	Allowance for Working Capital	Exh.S-2, Sch. B4	1,249,328	-	1,249,327
16	Total Rate Base	Line 14 + Line 15	21,242,782	(776,550)	20,466,232

Source Reference:
Historical Ending 12/31/2020 Balances: Exh. A-2, Sch. B5
Projected Average 10/31/2023 Balances: Exh. A-12, Sch. B4.1

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Energy Company
Projected Net Operating Income
for the Test Year Ended October 31, 2023
($000)

Case No.: U-20836
PFD
Appendix C

		Revenue				Expenses									NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line No.	Description (Witness)	Sales Revenue	Base Fuel & Purchase Power Rev.	Other Revenue and R2 Rider	Total	Fuel and Purchased Power	Other O&M Expense	Depreciation & Amort.	Property Taxes	Other Taxes	State & Local Income Taxes	FIT	Other Utility (Income) / Deductions	Total	NOI	AFUDC	Loss on Reacquired Securities	Adjusted NOI
	Company Filed																	
	Operating Income (Initial Filing)	3,611,715	1,359,740	109,068	5,080,523	1,359,740	1,280,715	1,087,914	307,739	48,573	54,386	83,250	(158)	4,222,159	858,364	44,400	(3,565)	899,199
	Tree Trim Surge Savings O&M						(4,200)				261	827		(3,112)	3,112			3,112
	Customer Service Represent.						(950)				59	187		(704)	704			704
	Merchant Fees						(2,970)				184	585		(2,201)	2,201			2,201
	Pension Expense						(8,600)				534	1,694		(6,372)	6,372			6,372
	Depreciation (from Cap Ex Adj)							(1,798)			112	354		(1,332)	1,332			1,332
	Interest Sync										-	93		93	(93)			(93)
	Rounding	-	-	-	-	-	-	-	-	-	-	4	-	4	(4)	-	-	(4)
1	**Operating Income (Reply Brief)**	3,611,715	1,359,740	109,068	5,080,523	1,359,740	1,263,995	1,086,116	307,739	48,573	55,536	86,994	(158)	4,208,535	871,988	44,400	(3,565)	912,824
	PFD Adjustments																	
2	**REVENUE**																	
3	Sales Revenue (Braunschweig)	2,312	275		2,587	275					144	455		874	1,713			1,713
4	Sales Rev. (Revere, Ausum, Kindsc	0			-	0					-	-		-	-			-
5					-						-	-		-	-			-
6	**STEAM POWER GENERATION**				-						-	-		-	-			-
7	Steam Power Generation O&M (Kindschy)				-		(4,581)				284	902		(3,394)	3,394			3,394
8	**DISTRIBUTION**				-						-	-		-	-			-
9	Distribution Ops (AG)				-		(1,200)				75	236		(889)	889			889
10	Retoration O&M (Becker)				-		14,777				(918)	(2,910)		10,949	(10,949)			(10,949)
11	Community Lighting (Wang. MI-MAUI)				-		(377)				23	74		(279)	279			279
12	**CUSTOMER SERVICE**				-						-	-		-	-			-
13	Distribution Ops App Health (capital to O&M with downward adjustment) (Wang)				-		685				(43)	(135)		507	(507)			(507)
14	Distribution Ops App Health (O&M adjustment, decrease by 48%) (Wang)				-		(14)				1	3		(11)	11			11
15	Fuel Supply Application Health (Wang)				-		404				(25)	(80)		299	(299)			(299)
16	IT O&M (Wang)				-		(2,876)				179	566		(2,131)	2,131			2,131
17	Level 1 IT Projects (100%) (Rogers)				-		(4,293)				267	845		(3,181)	3,181			3,181
18	Level 2 IT Projects (20%) (Rogers)				-		(2,572)				160	506		(1,905)	1,905			1,905
19	Merchant Fees (McMillan-Sepkoski)				-		-				-	-		-	-			-
20	Custome Service Representatives (AG)				-		(8,750)				543	1,723		(6,483)	6,483			6,483
21	**UNCOLLECTIBLES**				-						-	-		-	-			-
22	Uncollectible Expense (AG)				-		(9,400)				584	1,851		(6,965)	6,965			6,965
23	**REGULATED MARKETING**				-						-	-		-	-			-
24	Residential Battery Pilot O&M (Matthews)				-		(183)				11	36		(136)	136			136
25					-						-	-		-	-			-
26					-						-	-		-	-			-
27	**CORPORATE SERVICES**				-						-	-		-	-			-
28	Incentive Compensation (McMillan-Sepkoski)				-		(42,537)				2,642	8,378		(31,517)	31,517			31,517
29	Restricted Stock (McMillan-Sepkoski)				-		(5,857)				364	1,154		(4,340)	4,340			4,340
30	Pension Expense (Staff)				-		(600)				37	118		(445)	445			445
31	Active Healthcare (AG)				-		(9,500)				590	1,871		(7,039)	7,039			7,039
32	Impact of Cap Ex Adj on Depreciation (Schreur)							(45,658)			2,835	8,993		(33,830)	33,830			33,830
	Reclass Stat Tax and FIT in DTE Interest Sync Calc										22	(22)						
33	Proforma Interest (Nichols)				-						714	2,264		2,977	(2,977)			(2,977)
34	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	2	6	-	8	(8)	-	-	(8)
35	**Total Adjustments**	2,312	275	-	2,587	275	(76,873)	(45,658)	-	-	8,491	26,836	-	(86,929)	89,516	-	-	89,516
36	**PFD NOI - Test Year**	3,614,027	1,360,015	109,068	5,083,110	1,360,015	1,187,122	1,040,458	307,739	48,573	64,027	113,831	(158)	4,121,606	961,504	44,400	(3,565)	1,002,341

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For Period Ending October 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure				Weighted Costs			
Line No.	Description	Amounts ($000)	Percent Permanent Capital	Percent of Total Capital	Cost Rate %	Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long-Term Debt	8,410,859	50.0%	39.55%	3.69%	1.84%	1.46%	1.0000	1.46%
2	Preferred Stock	0	0.0%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	8,426,264	50.0%	39.62%	9.90%	4.95%	3.92%	1.3496	5.29%
4	Total	16,837,123	100.0%			6.80%			
5	Short-Term Debt	265,492		1.25%	1.74%		0.02%	1.0000	0.02%
6	Investment Tax Credit (ITC) - Debt	23,688		0.11%	3.69%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	23,688		0.11%	9.90%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	47,376							
9	Deferred Income Taxes (Net)	4,117,952		19.36%	0.00%		0.00%		0.00%
10	Total	21,267,943		100.00%			5.42%		6.79%

($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total	Test Year Impacts			
Line	Adjustment Description		Cap Ex Adj.	Plant	Accum Dep.	Rate Base	Depreciation
1	**PRODUCTION PLANT**						
2	Production: Steam Generation - Routine Additions	Renaissance Unit 1 Peaker Turbine Combution Cans & Hot Gas Path	(11,709)	(5,855)	(88)	(5,766)	(177)
3	Production: Steam Generation - Routine Additions	Monroe Unit 3 Waterfall Tubes	(868)	(434)	(7)	(427)	(13)
4	Production: Steam Generation - Routine Additions	Bell River - Avoidable Spend with 2026 Retirement	(12,775)	(6,388)	(96)	(6,291)	(193)
5	TOTAL - Production: Steam Generation - Routine Additions		(25,352)	(12,676)	(191)	(12,485)	(383)
6							
7	Production: Steam Generation - Non-Routine Additions	Monroe Bottom Ash Conversion (ELG)	(15,073)	(11,740)	(283)	(11,456)	(355)
8	Production: Steam Generation - Non-Routine Additions	Monroe FGD Wastewater (ELG)	(1,833)	(1,333)	(31)	(1,302)	(40)
9	Production: Steam Generation - Non-Routine Additions	Sibley Quarry Landfill Modification (CCR)	(4,244)	(3,090)	(71)	(3,019)	(93)
10	Production: Steam Generation - Non-Routine Removals	Monroe Bottom Ash Basin Closure (CCR)	(36,916)	-	26,811	(26,811)	-
11	Production: Steam Generation - Non-Routine Removals	River Rouge Decommissioning	(29,108)	-	19,774	(19,774)	-
12	Production: Steam Generation - Non-Routine Removals	St. Clair Decommissioning	(26,730)	-	19,407	(19,407)	-
13	Production: Steam Generation - Non-Routine Removals	Trenton Channel Decommissioning	(43,288)	-	27,445	(27,445)	-
14	TOTAL - Production: Steam Generation - Non-Routine Removals		(157,192)	(16,163)	93,051	(109,214)	(488)
15							
16	Production: Hydraulic Generation - Non-Routine	Ludington Upgrades	(3,305)	(3,078)	(137)	(2,941)	(82)
17	TOTAL - Production: Hydraulic Generation - Non-Routine		(3,305)	(3,078)	(137)	(2,941)	(82)
18							
19	Production: Other Generation - Non-Routine	Black Start Infrastructure, Site Security & NERC Compliance	(18,283)	(9,583)	(102)	(9,480)	(190)
20	Production: Other Generation - Non-Routine	Hydrogen Fuel System Pilot	(18,240)	(9,539)	(101)	(9,438)	(189)
21	Production: Other Generation - Non-Routine	Slocum Battery Pilot	(28,187)	(14,972)	(163)	(14,810)	(296)
22	TOTAL - Production: Other Generation - Non-Routine		(64,710)	(34,094)	(366)	(33,728)	(675)
23			-	-	-	-	-
24	**TOTAL PRODUCTION**		**(250,559)**	**(66,011)**	**92,357**	**(158,367)**	**(1,628)**
25							
26	**DISTRIBUTION**						
27	Distribution: Base Capital Programs	Emergent Replacements	(91,957)	(66,606)	(2,065)	(64,541)	(2,724)
28	Distribution: Base Capital Programs	Gordie Howe International Bridge	(414)	(331)	(11)	(320)	(14)
29	Distribution: Base Capital Programs	System Improvements - Major Equipment	(11,176)	(8,095)	(251)	(7,844)	(331)
30	Distribution: Base Capital Programs	System Improvements - NRUC and Blankets	(13,883)	(10,056)	(312)	(9,744)	(411)
31	Distribution: Base Capital Programs	System Improvements - General Plant, Tools & Equipment, and Miscellaneous	(3,032)	(2,196)	(68)	(2,128)	(90)
32	TOTAL - Distribution: Base Capital Programs		(120,462)	(87,284)	(2,707)	(84,576)	(3,570)
33							
34	Distribution: Strategic Capital Programs	Infrastructure Resilience and Hardening	(91,768)	(65,811)	(2,025)	(63,786)	(2,692)
35	Distribution: Strategic Capital Programs	4.8 kV Hardening to 2021 Levels	(54,152)	(39,694)	(1,242)	(38,452)	(1,623)
36	Distribution: Strategic Capital Programs	Pole and Pole Top Hardware (PTMM) to 2021 Levels	(54,989)	(34,424)	(940)	(33,484)	(1,408)
37	Distribution: Strategic Capital Programs	Subtransmission Redesign & Rebuild: Small Projects and Reserve	(2,917)	(1,459)	(30)	(1,429)	(60)
38	Distribution: Strategic Capital Programs	Infrastructure Redesign and Modernization	(156,992)	(113,975)	(3,540)	(110,435)	(4,662)
39	Distribution: Strategic Capital Programs	Pilot: Strategic & Service Undergrounding	(51,883)	(33,492)	(942)	(32,549)	(1,370)
40	Distribution: Strategic Capital Programs	CVR/VVO	(14,501)	(7,251)	(148)	(7,102)	(297)
41	Distribution: Strategic Capital Programs	Technology & Automation - NWA: Veridian	(6,486)	(4,010)	(108)	(3,902)	(164)
42	Distribution: Strategic Capital Programs	Technology & Automation - Technology Programs & NWA	(2)	(2)	(0)	(2)	(0)
43	Distribution: Strategic Capital Programs	Technology & Automation - High-Level T-Shirt Sizing Cost Estimates	(25,786)	(17,756)	(554)	(17,202)	(726)
44	Distribution: Strategic Capital Programs	Technology & Automation - Automation Configuration and Test Record Database	(3,870)	(2,957)	(102)	(2,855)	(121)
45	Distribution: Strategic Capital Programs	Technology & Automation - Operational Technology and Error Free Communication	(12,941)	(12,775)	(886)	(11,888)	(522)
46	Distribution: Strategic Capital Programs	Technology & Automation - System Operations Center Modernization Project (SOC: ESOC)	(14,431)	(14,400)	(1,067)	(13,333)	(589)
47	Distribution: Strategic Capital Programs	Technology & Automation - System Operations Center Modernization Project (SOC: ASOC)	(30,531)	(19,713)	(576)	(19,137)	(806)
48	Distribution: Strategic Capital Programs	Technology & Automation - Grid Automation Telecommunications (13.2kV)	(25,131)	(19,334)	(842)	(18,492)	(791)
49	Distribution: Strategic Capital Programs	Technology & Automation - NWA: O'Shea Energy Storage	(1,302)	(1,294)	(93)	(1,201)	(53)
50	Distribution: Strategic Capital Programs	Technology & Automation - NWA: Omega Load Relief (Labor)	(1,852)	(1,772)	(99)	(1,674)	(72)
51	Distribution: Strategic Capital Programs	Technology & Automation - NWA: Port Austin Load Relief	(2,083)	(1,042)	(21)	(1,020)	(43)
52	Distribution: Strategic Capital Programs	Technology & Automation - NWA: EV Charging Demonstration at ACM	(858)	(636)	(27)	(610)	(26)
53	Distribution: Strategic Capital Programs	Technology & Automation - DERMS Duplicative Project	(2,540)	(1,270)	(127)	(1,143)	(254)
54	Distribution: Strategic Capital Programs	Technology & Automation - DERMS Duplicative Project - Add Back Company Brief Adjustment	2,500	2,227	385	1,841	445
55	Distribution: Strategic Capital Programs	Technology & Automation - Interconnection Process Enablement	(5,086)	(3,720)	(116)	(3,604)	(152)
56	Distribution: Strategic Capital Programs	Technology & Automation - High-Level Cost Estimates	(7,881)	(5,752)	(207)	(5,545)	(235)
57	Distribution: Strategic Capital Programs	Technology & Automation - Other Costs	(10,626)	(8,777)	(400)	(8,377)	(359)
58	Distribution: Strategic Capital Programs	Technology & Automation - Historic Spend versus Projected Cost Analysis	(24,676)	(19,686)	(841)	(18,845)	(805)
59	Distribution: Strategic Capital Programs	AMI - Meter Communications Upgrade	(5,429)	(5,179)	(519)	(4,660)	(212)
60	TOTAL - Distribution: Strategic Capital Programs		(606,213)	(433,951)	(15,066)	(418,885)	(17,596)
61							
62	Distribution: Community Lighting	New Installations	(2,018)	(1,657)	(82)	(1,575)	(68)
63	Distribution: Community Lighting	Post Charge	(985)	(768)	(34)	(734)	(31)
64	TOTAL - Distribution: Community Lighting		(3,002)	(2,425)	(116)	(2,310)	(99)
65							
66	**TOTAL DISTRIBUTION**		**(729,677)**	**(523,660)**	**(17,889)**	**(505,771)**	**(21,266)**

Michigan Public Service Commission
DTE Electric Company
Capital Expenditure Adjustments
Projected Balances Period Ending October 31, 2023
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total	Test Year Impacts From Staff Adjustment(s)			
Line	Adjustment Description		Cap Ex Adj.	Plant	Accum Dep.	Rate Base	Depreciation
67	Demand Side Management	Other Demand Response Pilots - Window AC DR Pilot	(702)	(458)	(64)	(394)	(92)
68	Demand Side Management	Other Demand Response Pilots - Res. Generation DR Pilot	(419)	(301)	(45)	(256)	(60)
69	Demand Side Management	Other Demand Response Pilots - C&I Storage	(2,872)	(2,114)	(341)	(1,773)	(423)
70	**TOTAL DEMAND SIDE MANAGEMENT**		**(3,992)**	**(2,873)**	**(450)**	**(2,423)**	**(575)**
71							
72	Information Technology	Level 1 IT Projects (100% Disallowance)	(50,726)	(25,363)	(2,536)	(22,827)	(5,073)
73	Information Technology	Level 2 IT Projects (20% Disallowance)	(35,949)	(27,773)	(4,410)	(23,362)	(5,555)
74	Information Technology	Corporate Application - Reservation Application	(500)	(500)	(183)	(317)	(100)
75	Information Technology	Corporate Application - Controllers Financial Planning Tool	(2,800)	(2,494)	(432)	(2,062)	(499)
76	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Platform Integration - SAP Integration Business	(2,350)	(2,093)	(362)	(1,731)	(419)
77	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Automated Application Monitoring Enhancement	(2,720)	(2,542)	(651)	(1,891)	(508)
78	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Supporting Capabilities - Test Data and Test Data Mar	(1,170)	(1,042)	(180)	(862)	(208)
79	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Authentication & ID Management	(910)	(910)	(334)	(576)	(182)
80	Information Technology	Infrastructure Operations - Command Center Stand Up	(450)	(428)	(122)	(306)	(86)
81	Information Technology	Information Technology for IT - GRC Tool Expansion for Reg. Assets	(450)	(450)	(165)	(285)	(90)
82	Information Technology	IT Projects without Business Cases - MIGP - Integrate DTE Insight	(360)	(343)	(98)	(244)	(69)
83	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Digital Experience Group	(3,110)	(3,110)	(1,762)	(1,348)	(622)
84	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Digital Product Teams	(15,969)	(13,894)	(3,557)	(10,337)	(2,779)
85	Information Technology	Customer Service (Strategic, Enhancements & Compliance) - Pre-Pay	(12,622)	(10,299)	(2,927)	(7,371)	(2,060)
86	Information Technology	IT Cost Capitalization Concerns	(6,049)	(4,857)	(1,094)	(3,763)	(971)
87	Information Technology	Historic Spend and Projected Cost Analysis	(317)	(282)	(49)	(234)	(56)
88	Information Technology	DERMS Implementation Project	(1,667)	(1,484)	(257)	(1,227)	(297)
89	**TOTAL - INFORMATION TECHNOLOGY**		**(138,119)**	**(97,862)**	**(19,120)**	**(78,742)**	**(19,572)**
90							
91	Corporate Staff	Headquarters Energy Center	(7,700)	(7,700)	(1,070)	(6,630)	(584)
92	Corporate Staff	Headquarters Energy Center - Add Back Company Brief Adjustment	700	700	97	603	53
93	Corporate Staff	Electric Vehicle Fleet & Maintenance	(20,425)	(10,213)	(387)	(9,825)	(774)
94	Corporate Staff	Enterprise Automation	(11,002)	(5,501)	(550)	(4,951)	(1,100)
95	**TOTAL - CORPORATE STAFF**		**(38,427)**	**(22,714)**	**(1,910)**	**(20,804)**	**(2,405)**
96							
97	Residential Battery Pilot	Residential Battery Pilot	(4,244)	(2,672)	(36)	(2,636)	(53)
98	**TOTAL - RESIDENTIAL BATTERY PILOT**		**(4,244)**	**(2,672)**	**(36)**	**(2,636)**	**(53)**
99							
100	Production: Other Generation - Non-Routine	CONTINGENCY - Blue Water Energy Center (CCGT)	(8,100)	(8,100)	(294)	(7,806)	(160)
101	**TOTAL - CONTINGENCY**		**(8,100)**	**(8,100)**	**(294)**	**(7,806)**	**(160)**
102							
103	**TOTAL**		**(1,173,118)**	**(723,891)**	**52,658**	**(776,550)**	**(45,658)**

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN	)	
	) SS.	Case No. U-20836
County of Ingham	)	
	)	

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on September 19, 2022, she served a copy of the attached Notice of Proposal for Decision and Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

Meaghan Dobie

Meaghan Dobie

Subscribed and sworn to before me this
19th day of September 2022.

Brianna L. Brown

Brianna L. Brown
Notary Public, Gratiot County, Michigan
My Commission Expires July 4, 2028

Case No. U-20836
Service List

DTE Electric Company
Jon P. Christinidis
Lauren D. Donofrio
Andrea E. Hayden
Paula Johnson-Bacon
David S. Maquera
Breanne K. Reitzel
Carlton D. Watson
jon.christinidis@dteenergy.com
lauren.donofrio@dteenergy.com
andrea.hayden@dteenergy.com
paula.bacon@dteenergy.com
david.maquera@dteenergy.com
carlton.watson@dteenergy.com
breanne.reitzel@dteenergy.com
mpscfilings@dteenergy.com

MPSC Staff
Benjamin J. Holwerda
Daniel E. Sonneveldt
Nicholas Q. Taylor
Lori Mayabb
holwerdab@michigan.gov
sonneveldtd@michigan.gov
taylorn10@michigan.gov
mayabbl@michigan.gov

Attorney General Dana Nessel
Joel B. King
Sebastian Coppola
kingj38@michigan.gov
sebcoppola@corplytics.com
ag-enra-spec-lit@michigan.gov

Energy Michigan, Inc.
Michigan Energy Innovation Business Council
Institute for Energy Innovation
ChargePoint, Inc.
Bloom Energy Corp.
Laura A. Chappelle
Timothy J. Lundgren
Justin K. Ooms
lchappelle@potomaclaw.com

tlundgren@potomaclaw.com
jooms@potomaclaw.com

Michigan Environmental Council
Natural Resources Defense Council
Sierra Club
Citizens Utility Board of Michigan
Tracy Jane Andrews
Christopher M. Bzdok
Kimberly Flynn
Karla Gerds
Jill Smigielski
Breanna Thomas
tjandrews@envlaw.com
chris@envlaw.com
kimberly@envlaw.com
karla@envlaw.com
jill@envlaw.com
breanna@envlaw.com

Sierra Club
Shannon W. Fisk
Hema Devi Lochan
sfisk@earthjustice.org
hlochan@earthjustice.org

Michigan Cable Telecommunications Association
Michael S. Ashton
mashton@fraserlawfirm.com
ljohnson@fraserlawfirm.com

Association of Businesses Advocating Tariff Equity
Stephen A. Campbell
Michael J. Pattwell
Jim Dauphinais
Brian C. Andrews
Chris Walters
Jessica York
scampbell@clarkhill.com
mpattwell@clarkhill.com
jdauphinais@consultbai.com
bandrews@consultbai.com
cwalters@consultbai.com
jyork@consultbai.com

The Kroger Company
Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn
Justin Bieber
mkurtz@BKLlawfirm.com
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
jbieber@energystrat.com

Gerdau MacSteel, Inc.
Jennifer Utter Heston
jheston@fraserlawfirm.com

Local 223, Utility Workers Union of America (UWUA), AFL-CIO
Benjamin L. King
John R. Canzano
bking@michworkerlaw.com
jcanzano@michworkerlaw.com

Environmental Law & Policy Center
Ecology Center
Vote Solar
Nicholas Schroeck
Alondra Estrada
Heather Vogel
Daniel Abrams
schroenj@udmercy.edu
aestrada@elpc.org
hvogel@elpc.org
dabrams@elpc.org
mpscdocket@elpc.org

Michigan Municipal Association for Utility Issues
City of Ann Arbor
Valerie J.M. Brader
Valerie Jackson
Rick Bunch
valerie@rivenoaklaw.com
valeriejackson@rivenoaklaw.com
rick@mi-maui.org

Walmart, Inc.
Melissa M. Horne
mhorne@hcc-law.com

Great Lakes Renewable Energy Association
Residential Customer Group
Don L. Keskey
Brian W. Coyer
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com
adminasst@publiclawresourcecenter.com

Soulardarity
We Want Green, Too
Andrew Bashi
Mark Templeton
Jackson Koeppel
Simone Gewirth
andrew.bashi@glelc.org
templeton@uchicago.edu
jkoeppel.consulting@gmail.com
sgewirth@uchicago.edu
aelc_mpsc@lawclinic.uchicago.edu

Zeco Systems, Inc.
Sean P. Gallagher
Tom Ashley
Kathryn Chelminski
sean@legalspg.com
tom@greenlots.com
kchelminski@shellrecharge.com

EVgo Services, LLC
Brian R. Gallagher
Nikhil Vijaykar
Rachel Bird
bgallagher@mobloflem ing.com
nvijaykar@keyesfox.com
rachel.bird@evgo.com

International Transmission Company
Richard J. Aaron
Olivia R.C.A. Flower
Lisa M. Agrimonti
raaron@dykema.com
oflower@dykema.com
lagrimonti@fredlaw.com
mpscfilings@dykema.com
docketing@fredlaw.com